Attachment 02.1

Tariff Structure Statement | Explanatory Statement

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Contents

1 Introduction

This introductory chapter explains the purpose, scope and structure of this document.

1.1 Purpose of our Tariff Structure Statement (TSS) explanatory statement

Power and Water Corporation (Power and Water) is responsible for delivering energy from power generators to your homes and businesses in a safe and reliable way. While your retailer (e.g. Jacana Energy, Rimfire Energy, Next Business Energy or QEnergy) charges you for your energy usage, they pay us, on your behalf, for our services.

Our Tariff Structure Statement (TSS) relates to Power and Water's electricity network tariffs (tariffs) and various user-pays charges we have for regulated ancillary services. It explains our five-year tariff strategy, outlining what tariffs we will charge, and who will be assigned to which tariffs.

This document, our Tariff Structure Statement | Explanatory statement (explanatory statement), further details how our TSS and approach to annual tariff setting comply with the relevant rule provisions for matters that the Australian Energy Regulator (AER) did not approve in its September 2018 Draft Decision. It should be read in conjunction with our revised TSS.

Our tariffs recover the costs of building and maintaining the poles and wires, and the support staff needed to keep the energy network operating. This includes restoring power when faults and emergencies happen as a result of severe weather events and other causes beyond our control. The costs we can recover are regulated and must be approved by the AER every five years. The first regulatory approval period under the AER will be from 1 July 2019 to 30 June 2024. The tariffs in our TSS (if approved by the AER) will commence on 1 July 2019.

We have engaged with our stakeholders and customers to develop our first TSS, including publishing a draft overview of this TSS for consultation in November 2017, submitting our initial TSS proposal to the AER on 31 January 2018, consulting on the AER's Draft Decision, and submitting our revised TSS proposal on 29 November 2018. Further updates have been made, in consultation with the AER, subsequent to our revised submission in November 2018.

We will seek the AER's approval by early 2019, and will ensure our annual tariff proposals align to it within the 2019-24 regulatory control period.

For most customers, changes in our prices have no impact on their retail bills. This is because retail pricing protection applies under the Northern Territory (NT) Government's Electricity Pricing Order (the Pricing Order).

1.2 Scope of our explanatory statement

This document provides evidence of our compliance with the National Electricity (NT) Rules (NT NER – the Rules), particularly as regards the network pricing rule requirements of 6.18.5 (pricing principles).

The scope of network services covered by our TSS and hence this explanatory statement includes:

- standard control services; and
- alternative control services.

1.3 National Electricity (NT) Rules (NT NER – the Rules)

Below we outline the relevant Rules and reference where they are addressed in our TSS and explanatory statement.

1.3.1 Tariff structure statement requirements

Clause 6.18.1 specifies that a TSS must include the following elements:

- the tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period – discussed in TSS section 2.1;
- the policies and procedures the Distribution Network Service Provider will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another (including any applicable restrictions) – discussed in TSS section 2.2;
- the structures for each proposed tariff – discussed in TSS section 3;
- the charging parameters for each proposed tariff – discussed in TSS section 3; and
- a description of the approach that the Distribution Network Services Provider will take in setting each tariff in each pricing proposal of the Distribution Network Services Provider during the relevant regulatory control period – discussed in TSS section 4.[1]

Our TSS is also governed by the following clauses in the Rules:

- 6.18.3 Tariff classes – discussed in TSS section 2.1;
- 6.18.4 Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging – discussed in TSS section 2.2; and
- 6.18.5 Pricing principles – discussed below and in chapter 3.

1.3.2 Pricing principles and objective requirements

The Rules also require that a TSS must comply with the network pricing objective and pricing principles for direct control services.[2]

Our tariff structures must support the following network pricing objective:

> The tariffs that we charge for providing regulated network services to a retail customer should reflect our efficient costs of providing those services.

[1] NT NER 6.18.1(a).
[2] NT NER 6.18.1(b).

This objective is designed to support our customers' long-term interests. Research by the CSIRO and Energy Networks Australia shows that billions of dollars of energy infrastructure investment can be saved across Australia if we, as an energy network provider, get this right. It will also support our customers to make informed choices about how they source and use electricity as the energy sector transforms in the future, through new technologies and renewables policies.

The pricing principles we must also adhere to may be summarised as:

- Revenues from a given group of customers (called a tariff class) must be less than standalone cost and greater than avoidable cost.
- Our tariffs must be based on long-run marginal cost (LRMC).
- Our tariffs must recover the efficient cost of servicing customers on that tariff, recover the revenue amount allowed by the Regulator, and ensure the manner of recovery doesn't distort efficient customer use decisions.
- We must consider the customer impact principle and transition.
- Our tariffs must be easy to understand for retail customers.
- We must comply with all rules and regulations.[3]

We have developed our proposed tariffs to support the network pricing objective and comply with these pricing principles (as we explain further in chapter 3).

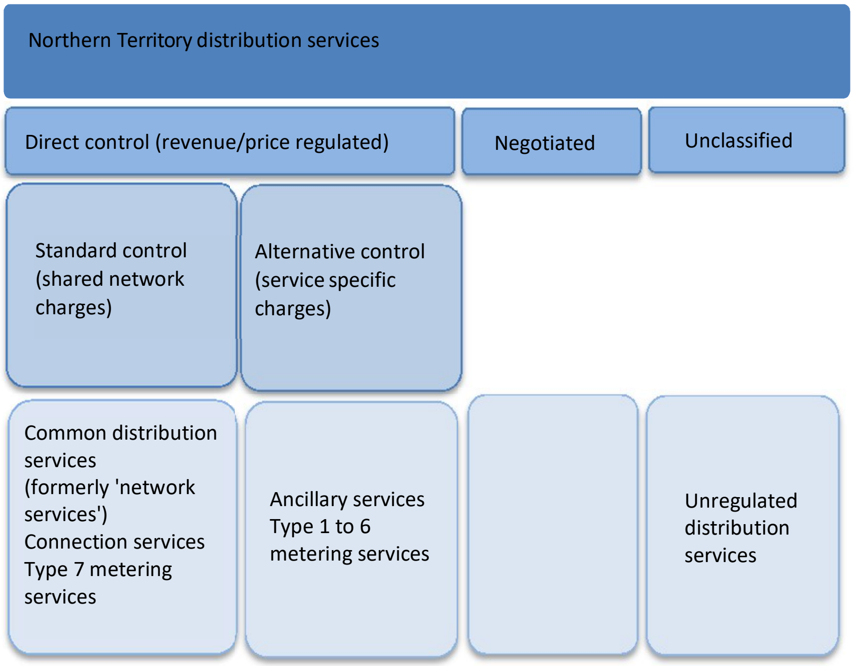
1.3.3 Classification of distribution services

The standard control services and alternative control services covered in this TSS have been classified by the AER in its July 2017 *Framework and Approach | Power and Water Corporation (NT) Regulatory control period commencing 1 July 2019* (the 'framework and approach').

The following figure summarises the AER's classification. The services covered by the direct control categorisation are covered in our TSS.

[3] NT NER 6.18.5

Figure 1 – AER service classification



Source: AER

Service classifications determine which distribution services will be regulated by the AER, and where regulated, how they will be regulated. We have adopted the AER's proposed service classification. Table 1 details the 2019-24 service classification, and compares it to the classification for the 2014-19 regulatory control period. The cells shaded in light grey signify a change in service classification between the regulatory periods. The key change in the service classification is for our Type 1 to 6 metering services, which will become alternative control services (ACS) in the 2019-24 regulatory control period.

Table 1 Service classification comparison across regulatory control periods

Service group/activities included	2014–19 classification[4]	2019–24 classification
Common distribution services		
Common distribution services	SCS	SCS
Ancillary services		
Design related services	ACS	ACS
Connection application related services	ACS	ACS
Access permits, oversight and facilitation	ACS	ACS
Notices of arrangement and completion notices	ACS	ACS
Network related property services	ACS	ACS
Site establishment services	ACS	ACS
Network safety services	N/A	ACS
Network tariff change request	ACS	ACS
Services provided in relation to a Retailer of Last Resort (ROLR) event	ACS	ACS
Planned Interruption – Customer requested	N/A	ACS
Attendance at customer's premises to perform a statutory right where access is prevented.	ACS	ACS
Provision of training to third parties for network related access	N/A	ACS
Metering services		
Type 1 to 6 metering services[5]	SCS	ACS
Type 7 metering services	SCS	SCS
Customer requested provision of additional metering/consumption data	ACS	ACS
Connection services		
Connection services	SCS	SCS
Reconnections/disconnections	ACS	ACS
Unregulated distribution services (not covered by this TSS)		
Distribution asset rental	N/A	Unclassified

1.4 Structure of this explanatory statement

We have structured this explanatory statement as follows:

- Chapter 2 explains our tariff classes and tariff structures for our common distribution services and our approach to responding to matters raised by the AER in its Draft Decision.
- Chapter 3 describes how we design our new tariffs structures and indicative tariff levels to comply with the network pricing principles both in this TSS and annually within the 2019-24 regulatory control period.

[4] We note that the Utilities Commission (UC) used different terminology to classify our services in the current period to that used by the AER under the Rules: 1) the UC's "regulated network access service" is equivalent to SCS; 2) the UC's "excluded network access service not subject to effective competition" is equivalent to ACS, and 3) the UC's "excluded network access service subject to effective competition" is equivalent to the service not being classified, and therefore not regulated by the AER.

[5] Type 5 meters are currently not approved for use in the Northern Territory. When referring to type 1 to 6 metering services, this includes services relating to prepayment meters.

- Chapter 4 details changes to our alternative control services proposal in response to the Draft Decision.

Further explanatory information relevant to our proposed TSS was set out in our 31 January proposed TSS. Relevantly:

- Chapter 2 of that document explained who we are and the aspects of our operating environment that are relevant to pricing design and customer impacts.
- Chapter 3 of that document summarised the customer and stakeholder research and engagement that informed our TSS proposal.
- Section 6.9 of that document foreshadowed areas of potential future tariff refinement for consideration and consultation ahead of our 2024-29 TSS.

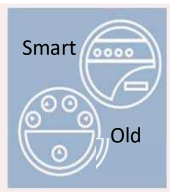
2 Network tariff classes, tariff assignment and tariff structures

This chapter explains the customer groupings (tariff classes) we use for assigning customers to tariffs, as well as the eligibility criteria and assessment process for tariff assignment.

2.1 Proposed network tariff classes for standard control services

We have kept the number of tariff classes to a minimum, to avoid unnecessary transaction costs. In addition, customers have been efficiently grouped together, recognising the material differences between customers arising from:

- the pattern and level of network usage as between residential and non-residential customers, which have different usage patterns and average consumption; and
- the nature of the plant or equipment required to provide the network access service, in the case of the high voltage (HV) tariff class, as these customers do not make use of the low voltage (LV) network or distribution substations.



Our meter types and capabilities

In the past, most customers have had meters that simply measured the total amount of energy used between meter reads. We call these standard accumulation meters.

Our largest energy users have had meters designed to measure the amount of energy used in 15 minute intervals. This detail provides information on their usage during our network peak times and off peak times. These meters also have communications capabilities which allow us to access meter data more frequently than once per month or quarter. We call these smart meters.

By 1 July 2019 all customers who use greater than 40MWh of energy per year will have had a smart meter installed at their property, capable of being remotely read.

From 1 July 2019 we plan to only install smart meters for new connections or when replacing a meter which has reached the ends of its service life. The AER's draft decision approved this plan.

Table 2 sets out our proposed tariff classes, and the proposed tariffs that would apply to customers in each tariff class. We also propose to provide for individually calculated tariffs for sufficiently large and unique customers for whom a bespoke tariff would best meet the NT NER pricing principles and protect the interests of our existing customers.

Table 2 Proposed network tariff classes

Tariff class	Description of tariffs
LV <750MWh	1 Residential customers consuming <750MWh pa per NMI with standard accumulation meters
	2 Non-residential customers consuming <750MWh pa per NMI with standard accumulation meters
	3 Customers consuming <750MWh pa per NMI with smart meters
	4 Unmetered supply (for street lighting, traffic lights and other unmetered devices)
LV >750MWh*	5 Customers connected to the LV network consuming >750MWh pa per NMI
HV*	6 Customers connected to the HV network consuming <750MWh pa per NMI
	7 Customers connected to the HV network consuming >750MWh pa per NMI

Notes: * For sufficiently large and unique new customers for whom a bespoke tariff would best meet the NT NER pricing principles and protect the interests of our existing customers, Power and Water may confidentially determine individually calculated tariffs in accordance with the eligibility arrangements and tariff setting approach set out in our TSS, and would seek AER approval of these in the annual tariff variation process.

2.2 Proposed network tariff structures

The following table sets out the tariff structures for our 2019-24 network tariffs for the LV less than 750MWh tariff class customers showing the applicable charging parameters.

Table 3 Tariff structures

Tariff	SAC	Anytime kWh ¢/kWh	Peak Demand $/kVA	~~kVAr* $/kVAr~~
1. Residential	×	×	-	-
2. Non-residential	×	×	-	-
3. LV Smart Meter	×	×	×	~~×~~
4. Unmetered Streetlights	-	x	-	-

~~* The kVAr charge will apply only to those LV Smart Meter customers with a consumption of greater than 40MWh per annum, and only from 1 July 2021.~~

The following table sets out the applicable charging parameters tariff for our LV >750MWh tariff class customers.

Table 4 LV greater than 750MWh charging parameters

Tariff	SAC	Anytime kWh ¢/kWh	Peak Demand $/kVA	~~kVAr* $/kVAr~~
5. LV >750MWh	×	×	×	~~×~~

~~* The kVAr charge will only apply from 1 July 2021.~~

The following table sets out the applicable charging parameters for the two tariffs available within the High Voltage tariff class.

Table 5 HV Charging Parameters

Tariff	SAC	Anytime kWh ¢/kWh	Peak Demand $/kVA	~~kVAr* $/kVAr~~
6. HV <750MWh	×	×	×	~~×~~
7. HV >750MWh	×	×	×	~~×~~

~~* The kVAr charge will only apply from 1 July 2021.~~

2.3 Changes in response to the Draft Decision

2.3.1 Low Voltage consuming less than 750MWh unmetered tariff category

Our initial proposal and feedback from stakeholders and the AER

Unmetered supplies cover public lighting, traffic lights and other unmetered installations such as CCTV. In the current 2014-19 regulatory control period, we applied a kWh energy charge for these connections using on an assumed consumption based on wattage rating and hours of operation.

We initially proposed changing our unmetered tariffs from a kWh tariff to a per Watt charge. This is consistent with the retail tariff structure prescribed in the Electricity Pricing Order. The revenue raised from unmetered connection points would remain largely unchanged as a result of changing the charging parameter.

The Local Government Association of the Northern Territory (LGANT) submitted to the AER that the proposed move away from kWh charges would remove councils' incentives to install more energy efficient lights and smart controls. Further to this, recent discussions with the Department of Treasury and Finance indicate a preference to adopt similar Type 7 metering arrangements (i.e. for unmetered supplies) as that in the NEM, including the adoption of AEMO load tables for deeming usage.

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In light of this new information, we informed the AER that we would review our approach to unmetered connection point tariffs. Accordingly, the AER's Draft Decision rejected our initial proposal.

Our revised proposal

We engaged with LGANT and various local government authorities (LGAs) to identify their plans for upgrading unmetered connection points (e.g. through LED lighting rollouts and smart device installations). From this we constructed an updated forecast of unmetered energy use over the 2019-24 regulatory control period.

With this additional information, we have reviewed our approach and propose to revert back to retaining a kWh charge. This will account for the forecast decline in energy consumption over the period based on our understanding of councils' plans to roll-out new LED public lighting.

We will continue to work with the NT Government to finalise the energy consumption calculation arrangements that will be adopted under the NT NER chapter 7A changes. This may include the adoption of the device load schedules published by AEMO, or an AEMO-like equivalent developed for NT circumstances. The intent is to adopt an independent view of load profiles that we can rely upon for billing.

We now propose a single flat rate anytime energy tariff in $/KWh for all unmetered connection points (Tariff 4). We no longer consider that the administrative complexity of differentiating between 12 hour and 24 hour operation is warranted. This is because:

- A single tariff can apply to all unmetered connection points, and our process of deeming the load can account for how many hours they operate;
- These tariffs only account for $1m of our annual revenues; and
- Other than adopting more energy efficient devices (which our device deeming process accommodates), there is no time of use behavioural change we are seeking to facilitate in the way unmetered connection points use our network, and these stable flat loads are not material enough to drive growth in our network costs.

We note that while our decision to maintain the status quo charging basis (i.e. $/KWh) will mean our network bills to retailers for unmetered connection points will vary as LGAs roll-out new LED public lighting and the introduction of smart sensors, this alone will not be sufficient to address their concerns.

Importantly, retailers still bill LGAs based on $/watt as prescribed in the Pricing Order. This Pricing Order also means that changes in our prices as a result of having an anytime energy charge covering both 12 and 24 hour operating devices will have no bill impact on these customers. Notwithstanding this, we have calculated the network bill impact of our proposal as being a one-off decrease of 1.7% in 2019-20 for 12 hour devices and a 26.9% decrease for 24 hour devices.

We have consulted with LGANT on our revised approach in October 2018 and they supported it, and highlighted that the Pricing Order would need to change to enable them to benefit from our revised approach.

2.3.2 LV and HV individually calculated tariffs

Our initial proposal and AER feedback

Our initial TSS proposal included provision to be able to introduce individually calculated tariffs for new large user customers whose total electricity consumption, per financial year, is ~~less~~ more than 750MWh per NMI and who are sufficiently large and unique that a bespoke tariff would best meet the NT NER pricing principles and protect the interests of our existing customers.

The AER's Draft Decision rejected this element of our TSS proposal stating:

> *"The proposal to introduce individually calculated tariffs is reasonable of itself. However, we deem greater detail regarding these tariffs is required to enable proper assessment against the requirements of the rules."*[6]

It requested that our revised proposal should provide information that increases transparency regarding individually calculated tariffs, including: 1) the eligibility criteria, and 2) the principles and methods on how Power and Water would calculate tariff levels for these bespoke tariffs.

Our revised proposal

Section 2.1 of our revised TSS now sets out the eligibility requirements for individually calculated tariffs in the LV greater than 750MWh tariff class and HV tariff class. Section 3.2 sets out our approach to calculating these tariffs. We explain these arrangements below.

HV and LV individually calculated tariff eligibility

In exceptional circumstances, Power and Water may offer an individually calculated tariff. This tariff may be made available to new customers with LV or HV >750MWh consumption per annum at a NMI, or material alternations to existing LV or HV >750MWh consumption per annum at a NMI where the conditions outlined below hold. ~~This tariff may be made available to new HV or LV greater than 750MWh connection points or material alternations to existing HV or LV greater than 750MWh connection points.~~

Power and Water will not be applying individually calculated tariffs to existing HV or LV greater than 750MWh ~~connection~~ consumption per annum per ~~at a~~ NMI~~spoints~~. This is because:

- the dedicated tariff cannot support material behavioural change aligned to the National Electricity Objective; and
- there are no connection or usage benefits available to off-set the additional administration and transaction costs associated with a bespoke tariff.

This means this tariff would not be a candidate for unilateral reassignment at Power and Water's initiation.

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[6] AER, Draft Determination, Attachment 18: Tariff structure statement | Draft decision – Power and Water Corporation Distribution determination 2019-24, p.18-27.

Any customer offered an individually calculated tariff can still opt for the relevant default tariff (i.e. either Tariff 5 or Tariff 7 depending on the voltage level at which they connect) at the time of connection or later subject to the terms of their connection agreement. Rather than a process of 'tariff assignment', this would be a confidential process of commercial negotiation where the parties acknowledge that the service sought is sufficiently different to the average service Power and Water provides at the existing default tariff(s), such that both parties agree it is mutually beneficial to negotiate a dedicated tariff.

The circumstances in which we may offer the option of an individually calculated tariff are where the connecting or augmenting party's apparent power requirement is greater than 2MVA, and one or more of the following exists:

- *The impact of connection charges should be reflected in a dedicated tariff* | Including either:
    - The customer faces material connection charges at the default tariff that will discourage connection or affect the viability of the project
    - The customer has a commercial preference for up-front capital contributions with a commensurately lower ongoing tariff.
- *Material network support benefits can be captured and shared* | Mutually beneficial demand management or embedded generation may be economic with a dedicated tariff but not on the default tariff, and these are of sufficient scale to warrant the transaction costs associated with a dedicated tariff.
- *Material uneconomic network* bypass *risk exists* | Uneconomic network bypass may otherwise occur where the customer would be willing to connect at avoidable cost plus some contribution to residual costs, but would likely bypass the network at the level of residual cost recovery inherent in the default tariff.

Materiality will be assessed having regard to:

- Total annual revenue forecast to be earned ~~from the connection point~~at the NMI, where this would generally need to be greater than 0.5% of Power and Water's annual revenues, because if less than this, it may be preferable to consider using the trial tariff previsions in rule 6.18.1C for sub-threshold tariffs.
- The administration and transaction costs we expect to incur and whether these are any greater than those that would otherwise be incurred in determining the associated connection contribution under our Customer Connection Services Policy.

Power and Water considers these eligibility arrangements are consistent with our tariffs during the 2019-24 regulatory control period best supporting the network pricing objective. Our largest customers are likely to have the bargaining power and the information necessary to arrive at mutually beneficial and commercially negotiated outcomes, particularly at the time of making their connection or augmentations decisions.

Setting individually calculated tariffs

The default tariff structure for these tariffs will have an individually calculated system access charge and demand charge. Depending on the customer's circumstances, and our ability to recover a sufficient allocation of residual costs from our preferred system access charge and demand charge, the tariff structure may also include a volume (kWh energy) tariff to recover a further contribution to residual cost recovery. ~~For most eligible customers we would not expect to need to levy an excess kVAr charge because their likely scale would make power factor management an economic consideration they would manage in their system design and operating decisions. However, where we consider this to be a risk for particular customer or site's energy usage purposes we may apply an excess kVAr charge.~~

Power and Water will calculate dedicated tariff levels for each charging parameter:

- drawing on the system-wide voltage level LRMC estimates contained in our TSS, and the voltage levels relevant to the connection or augmentation
- drawing on the more detailed locational cost data underpinning the incremental cost calculation used in assessing connection or augmentation
- considering any contributions paid by the customer at the time of connection
- assessing the desirable connection, demand management, and revenue sufficiency (i.e. above avoidable cost with some contribution to shared residual costs) outcome that best supports efficient connection and usage decisions by the customer
- ensuring the resulting revenues are greater than our avoidable cost to supply that customer.

Where a large connection's use of the shared system is limited, Power and Water would account for this in the residual cost allocation, and in which elements of its LRMC estimates it reflects in the charges (e.g. if a large customer has connected to the HV system and paid for all the dedicated LV assets in its connection contribution, then we would not reflect our LV LRMC estimate in the individually calculated charges).

2.3.3 kVAr charge Trial

Power and Water, in its ~~Initial Regulatory~~initial ~~–P~~proposal ~~(IRP)~~ and r~~R~~evised ~~Regulatory P~~proposal ~~(RRP)~~ put forward the proposal that from 2021-22 we should introduce a charge relating to customer's excess kVAr. That is, introduce a financial incentive for customers to ensure that their power factors are meeting minimum requirements as specified in our Network Technical Code.

After feedback from stakeholders and the AER, Power and Water have withdrawn this proposed charge from the proposed TSS. We will continue to investigate and work with stakeholders on how to encourage customers to improve their power factors, including the introduction of financial incentives through a tariff trial.

Power and Water notes that the NT NER provides provisions to introduce a charge under trial conditions using sub-threshold tariffs available under clause 6.18.1C. It may be appropriate for an excess kVAr charge, at some stage during the determination period, to be introduced in accordance with these conditions.

Consistent with our stakeholder engagement and resulting commitments to our customer arising from that engagement, we would not consider introducing a trial before 1 July 2021.

~~Setting excess kVAr charges~~

~~Our initial proposal included introducing an excess kVAr charge for all customers with a smart meter who consume greater than 40MWh per year. This charge will provide an incentive to customers to maintain their power factor within the standard required by our Network Technical~~ Code~~, thereby providing an economic efficient outcome for all users of the power system.~~

~~The AER's Draft Decision stated:~~

> ~~*"An excess kVAr charge can provide incentives for customers to fix poor power factors, which in turn can lower the costs of running the network."*~~[7]

> ~~*"We require Power and Water to clarify the technical requirement applicable to the connection of customer installations for the application of the excess kVAr charge in its revised proposal."*~~[8]

> ~~*"In principle, we consider introducing the excess kVAr charge is reasonable as a move along the cost reflective spectrum but have outstanding questions regarding the tariff levels Power and Water have set out in their indicative price schedule."*~~[9]

~~***Setting the charging level and providing an incentive***~~

~~Our initial proposal and revised proposal seek to provide sufficient incentives to customers to change behaviour, without causing significant customer impacts.~~

~~It should be noted that those customers consuming less than 750MWh per annum will be protected by the current Electricity Pricing Order, but Power and Water considers that the implementation of this charge may incentivise electricity retailers to develop appropriate pricing structures in the future.~~

~~We are proposing to provide customers with over 2 years of notification before introducing the charge. During this time, we will work with customers to improve their compliance. It is hoped that over these two years customers, through some relative minor changes and investment, will be able to significantly improve their compliance, thus avoiding the charge. Businesses should also see reductions in their bills, as their consumption and peak demand should also reduce.~~

~~We have assessed the cost-reflective price based on an LRMC calculation. Given an LRMC of around $20, the excess power factor would be around $8.70 to $11.80/kVAr.~~

[7] ~~Ibid, p.18-26.~~
[8] ~~Ibid, p.18-36.~~
[9] ~~AER, Draft Determination, Attachment 18: Tariff structure statement | Draft decision – Power and Water Corporation~~
~~Distribution determination 2019-24, p.18-21.~~

~~However, we do not consider that we need to charge the full price initially to provide a strong incentive for customers to change behaviour. This is a new charge, so any charge and the associated education campaign accompanying its introduction should result in favourable behavioural change. Coupled with the general benefits customers should gain from improved operational efficiency, we believe the $4/kVAr is sufficient. Thus, we indicatively propose to retain the $4/kVAr charge from 1 July 2021, which is based on Ergon's current rate.~~

~~Prior to its actual introduction in 2021-22 this value will be further assessed, taking into account customer reactions to the proposed charge, over the next few years. We will also consult with our Customer Advisory Council (CAC) on the proposed level of this charge prior to making that annual application.~~

~~We make the following observations about some of the matters raised in the AER's Draft Decision regarding setting this charge:~~

- ~~Because the rules require we only recover our allowed building block costs, it is reasonable to say that these excess kVAr charges are a means of recovering our allowed residual costs (given we have LRMC recovered through our demand charges), but of providing an efficient incentive signal in the process. We do not consider these concepts to be mutually exclusive.~~
- ~~Our engagement has shown our large customers (>750MWh pa) understand this charge and are capable of responding if given sufficient time to prepare.~~

Clarifying the power factor obligation

We confirm that the technical requirement applicable to the connection of customer installations for the application of the excess kVAr charge is 0.9 lagging to 0.90 leading (66kV) and 0.95 lagging to unity (66kV and above). This requirement is given effect through the Network Technical Code (3.6.7). ~~We have reflected this in our TSS description of the excess kVAr charging parameter.~~

The AER noted that we also have Service Rules (NP007) which discuss power factors. We note that the NP007 Service Rule is out of date (dated 21 Feb 2008) and is currently being updated to align with the Network Technical Code.

3 Approach to price setting

This chapter explains the relevant rule requirements for price setting and our compliance with these. It steps through how we set our tariffs both indicatively in the TSS and how we will approach annual tariff setting in a manner compliant with the TSS and rules.

3.1 Overview

We set tariffs by:

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- setting the tariffs at levels that ensure the revenue we expect to recover from customers lies between:
  - the stand-alone cost of serving those customers who belong to that tariff

class; and
  - the avoidable cost of not serving those customers;
- setting each nominated cost-reflective tariff charging parameter so that it is based on the LRMC of providing services to the customers assigned to that tariff;
- setting our tariffs to reflect the efficient costs of providing the services, including recovering:
  - our total allowed efficient building block revenue requirement (the BBRR), and
  - our residual costs (i.e. the BBRR net of LRMC recoveries)[10] in a manner that reflects their relative contribution to our total costs and from charging parameters that support a least demand-distortive outcome;
- considering and limiting the customer impact of changes to our tariffs; and
- ensuring our tariffs are appropriately simple and understandable to our customers.

3.2 Rule requirements

The network pricing objective has been specified in Rule 6.18.5(a) which requires that tariffs should reflect the efficient costs of providing services to customers using these tariffs. The pricing principles set out in clauses 6.18.5(e) - (j) of the Rules require us to ensure our tariffs:

- recover revenue from each tariff class that lies between the stand-alone cost of providing the service to the relevant customers and the avoidable cost of not providing the services;
- are based on the LRMC of providing the service;
- recover revenue that reflects our total efficient costs of providing services to the customers assigned to that tariff, and minimises distortions to efficient usage signals when recovering residual costs (i.e. our efficient costs in excess of LRMC);
- reflect our consideration of the impact on customers of changes in our network tariffs;
- have been developed to be reasonably able to be understood by our customers;
- must comply with any jurisdictional pricing obligations imposed by the NT Government; and
- comply with the Rules, including those for side constraints which limit annual price movements within a tariff class (from the second year of the determination).

3.3 Achieving compliance with the Rules

For this, our first TSS, we have developed our proposed tariff structures and indicative tariffs to comply with the above rule requirements in a manner which:

[10] Residual costs are the difference between our total revenues and revenues earned through our LRMC-driven charging parameters discussed in section 3.5.4.

- manages customer impacts of transition;
- recognises the impact of the Pricing Order;
- responds to customer and stakeholder feedback from our engagement, and
- responds to feedback from the AER in its Draft Decision.

In the past our tariff structures were established based on a vertically integrated electricity business, providing end-to-end services from generation through to retail. Therefore, most of our legacy tariff structures did not strongly reflect the drivers of our network costs and indeed for some customers, they actually provided discounted demand tariffs at the peak times when our cost drivers were highest.

In order to comply with the Rules, our prices must be cost reflective. These legacy tariffs needed to be changed to comply with the pricing principles set out in the Rules and be implemented in such a way that manages any impacts on our customers.

What is cost reflectivity? The amount customers pay should reflect their usage and demand placed on the network, including:

- the cost of them being connected to the network; and
- the demand they put on the network (particularly at peak times which drive growth in our costs).

What does cost reflectivity mean when setting our tariffs? Cost reflective pricing requires consideration of the following:

- how the way our customers use the network is reflected in how they are charged – we call this the *tariff structure*, identifying what components there are in the bill and how these relate to types of use and ultimately our costs; and
- how much (what share of costs) different customer groups pay based on how much of our total costs they account for – we call this our *revenue share*.

We have captured these requirements in our pricing design principles of 'simple, stable, fair and enough'. The following sections demonstrate how we have accounted for and complied with the pricing principles.

3.4 Approach to setting our proposed tariffs in 2019-24

Our approach to setting our proposed tariffs seeks to ensure:

- *more efficient tariff structures*: the way our customers use the network is reflected in how they are charged; and
- *more efficient revenue shares*: the amount different customers pay will reflect how much of our costs they drive.

We have implemented more efficient tariff structures (i.e. charging parameters) in the first year of the TSS period, 2019-20. These structures mean we will not need to make tariff charging parameter changes in the remaining years of the TSS period~~, other than for introducing the excess KVAr charge in 2021-22~~.

Our tariff structure setting approach means:

- demand charges are to be introduced for all customers with a suitable meter;
- demand tariffs are set at flat levels (rather than declining blocks) to encourage efficient energy use;
- energy tariffs are set at flat levels (rather than declining blocks) and don't provide discounts for high energy use;
- we have reduced our reliance on energy charges to recover residual costs;
- demand tariffs are set at our LRMC estimate for LV customers protected by the Pricing Order;
- demand tariffs are moving closer to our LRMC estimate for HV customers and LV customers with annual consumption greater than 750MWh per NMI who are not protected by the Pricing Order, given the need to manage bill impacts; and
- we have adjusted our peak charging period to 12:00 to 21:00 on week days to be better aligned to our current and predicted peak load profiles.~~; and~~
- ~~customers with annual consumption greater than 40MWh with a power factor that does not meet our system's technical requirements will be encouraged to implement corrective measures through introduction of an excess kVAr charge from 2021-22.~~

Our approach to more efficient revenue shares is achieved through:

- better aligning our recoveries of residual costs with our allocations of our cost of supply to different tariffs; and
- preferencing recovery of residual costs from fixed system access charges and demand charges, rather than energy charges, where this can be achieved whilst:
  - managing customer bill impacts; and
  - ensuring our LV smart meter tariff does not create a disincentive to be on that tariff relative to the equivalent residential and non-residential accumulation meter tariffs.

These tariff level rebalancing changes have been materially advanced in the first year of the TSS period, 2019-20. This has been achieved by:

- better aligning our recoveries of residual costs with our allocations of our cost of supply to different tariffs – as discussed in section 3.5.6 below;
- preferencing recovery of residual costs from fixed system access charges and demand charges, rather than energy charges, where this can be achieved whilst managing bill impacts, including making the following changes relative to 2018-19 tariffs:
  - increasing the system access charge for all tariffs (other than unmetered supplies which is an energy only tariff); and
  - lowering our consumption charges for all tariffs.

Where further required revenue movements arise within the TSS period that are not contemplated in this TSS (e.g. under and over recoveries under the revenue cap or changes in the AER's final determination) any further rebalancing would focus on:

- Continuing to progress our demand tariffs closer to our TSS LRMC estimates for HV customers and LV customers with annual consumption greater than 750MWh per NMI while managing bill impacts;
- Examining the role of demand charges in recovering residual costs (i.e. as we have more customers on demand charges, and have better data about the demand patterns of these customers, we may need to include some residual cost recoveries on our demand charges); and
- Directing any required revenue reductions to lower energy consumption tariffs for less than 750MWh tariff classes ~~customers~~.

3.5 Evidence of pricing compliance

3.5.1 Pricing within stand-alone and avoidable cost

As Table 6 shows, we have ensured the revenues we expect to recover from each tariff class are within the efficient pricing bounds required by rule 6.18.5(e). That is, they are:

- more than we would save if we didn't serve those customers – our avoidable cost – and thereby ensure we are not serving customers through inefficient levels of cross-subsidy; and
- less than the cost those customers would incur to build their own energy solutions – standalone cost.

Table 6 Stand-alone and avoidable cost ($'000 per year)

Revenue and cost measures	Tariff class		
	LV <750MWh	LV >750MWh	HV
Stand-alone cost	141,247	128,989	48,214
Forecasts 2019-20 tariff revenues	116,360	19,039	16,437
Avoidable cost	18,622	10,230	4,934

3.5.2 Pricing based on LRMC

Despite the existence of legacy prices and tariff structures that we need to manage customer impacts of transitioning away from, the following factors mean we will make significant advancement in how we reflect LRMC in our tariffs in the 2019-24 regulatory control period as required by rule 6.18.5(f):

- the roll out of smart meters to all customers consuming ~~less~~ more than 40MWh in the current regulatory control period, and approval of our roll out to all new and replacement meters from 2019-24;

- the presence of the Pricing Order for less than 750MWh tariff class customers; and
- the fall in our total revenue requirement (relative to the Ministerial Direction).

These circumstances have enabled us to:

- consider LRMC estimates in setting our demand charges;
- consider LRMC estimates in setting our energy consumption charges for tariffs that do not have a demand charge;
- introduce demand charges for all customers with smart meters consuming less than 750MWh per year per NMI; and
- remove the inefficient declining block demand tariff structure that previously applied to large users who consume greater than 750MWh per NMI per year.

3.5.3 LRMC estimates

The AER's Draft Decision approved our method of estimating LRMC (the average incremental cost approach, estimated for the HV system and the LV system).

As with our initial TSS proposal, our LRMC estimation was a two-step process wherein we:

- estimated LRMC for the whole of our three regulated networks by voltage level using current available inputs; and
- compared these LRMC estimates against those used by other distribution networks across the NEM to determine their tariffs, and against that which we had estimated previously and used for our 2014-19 network pricing determination.

Our revised TSS retains these initial proposal LRMC estimates. We have updated step 1 for the revised proposal data inputs. This shows that our LV calculated LRMC of $20.51 $/kVA/month is now more aligned to the initial proposal estimate of $20, however the calculated result for HV is lower.

Table 7 Long-run marginal cost estimates (real $2018-19)

Tariff class	TSS LRMC estimate $/kVA per month	Calculated estimate
LV <750MWh	20.00	20.51
LV >750MWh	20.00	20.51
HV	9.50	4.56

3.5.4 Reflecting LRMC estimates in our tariffs

Using the estimates in Table 7 above, we have checked that all of our tariffs recover the LRMC estimated to be associated with the forecast chargeable demand of customers on those tariffs. To do so we transformed the TSS LRMC estimates above into a required LRMC tariff for the nominated charging parameter having regard to the customers' coincident demand for demand tariffs and power factor for consumption tariffs, and adjusted for inflation up to the relevant pricing year.

Table 8 shows the outcome for 2019-20. When compared to our proposed 2019-20 tariffs, it shows that:

- demand tariffs have been set at our non-diversified LRMC estimate for LV customers protected by the Pricing Order; and
- demand tariffs are moving closer to our diversified LRMC estimate for HV customers and LV customers with annual consumption greater than 750MWh per NMI who are not protected by the Pricing Order, given the need to manage bill impacts.

Table 8 Long-run marginal cost tariff ($Nominal, 2019-20 year)

	SAC daily	Manual Meter	Smart	
		Consumption		Demand
Tariff	$/day	¢/kWh		S/kVA
LV Residential Accumulation	-	3.02	-	-
LV Non Residential Accumulation	-	3.08	-	-
Unmetered Supply	-	3.12	-	-
LV Smart Meter	-	-	-	9.22
HV <750MWh pa per NMI	-	-	-	8.27
LV >750MWh pa per NMI	-	-	-	17.41
HV >750MWh pa per NMI	-	-	-	8.27

We note that setting the demand tariff for LV customers protected by the Pricing Order at the non-diversified LRMC estimate makes this tariff higher than the contribution to the coincident peak that drives long-run system costs. However we consider this is a pragmatic way to ensure our customers' demand tariffs signal our LRMC while also recovering a contribution to our residual costs in a least demand-distortive manner.

As noted above, in future the role of demand charges in recovering residual costs (i.e. as we have more customers on demand charges) will need to be reviewed to ensure our tariffs remain least demand-distortive in their residual cost recoveries. This will be easier to assess and adjust for as we gain better data about the demand patterns of customers through our new and replacement smart meter roll out program.

3.5.5 Ensuring our tariffs reflect total efficient costs

We have ensured our tariffs only recover our total efficient costs as required by rule 6.18.5(g)(2). We have tested that the net present value (NPV) of multiplying our forecast indicative tariffs in this TSS and AEMO's forecast demand growth rates aligns to the NPV of the building block revenue requirement we have forecast using the AER post tax revenue model.

If the actual demand over the period differs from AEMO's forecast demand that we have relied on in this TSS, the revenue cap will adjust our annual prices to ensure we only recover our approved efficient costs.

3.5.6 Aligning our revenue shares with our cost to serve

In addition to recovering our total efficient costs, we are also better aligning the share of our revenue we receive from each tariff with how much those customers cost us to supply as required by rule 6.18.5(g)(1).

To do so, we allocated our efficient BBRR to tariffs to estimate an appropriate target allocation. This allocation is summarised in the table below.

Table 9 Approach to revenue allocation to tariffs

Costs	Share of building block revenue requirement	Basis of allocation
Transmission	17.4%	Contribution to coincident peak demand
Zone substations	28.5%	Contribution to coincident peak demand
HV distribution	19.1%	Contribution to coincident peak demand
Distribution substations	17.5%	Contribution to coincident peak demand
LV distribution	7.6%	The network costs for LV connected customers are allocated on the basis of usage by customers. The total costs are scaled to the number of phases of supply (<750 Residential customers = 1, <750 Non-residential customers = 2 (average), >750 Non-residential customers = 3. Streetlights and traffic lights (unmetered) are allocated costs based on their demand share of the LV distribution network.
Common services	10.0%	Allocated on the basis of energy

The resulting target allocation by tariff is shown in Table 10.

Table 10 Approach to revenue allocation to tariffs

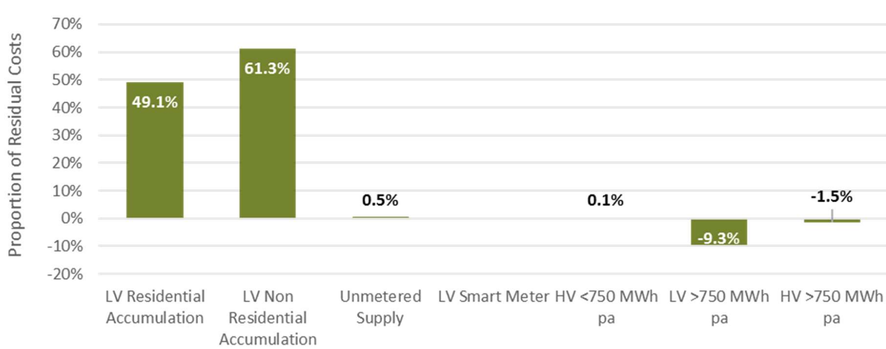
Tariff	Allocation %
Residential	25.1%
Non-residential	19.9%
Unmetered	0.1%
LV Smart <750MWh pa per NMI	33.3%
HV <750MWh pa per NMI	0.0%
LV >750MWh pa per NMI	10.3%
HV >750MWh pa per NMI	11.4%

We have compared our target allocations to our residual cost recoveries from each tariff. Residual costs are the difference between our total revenues and revenues earned through our LRMC-driven charging parameters discussed in section 3.5.4.

Figure 2 sets out the residual costs arising in 2018-19. Note that there is no allocation to smart meters are they are not a separate tariff in 2018-19.

In the past, our large non-residential tariffs have recovered a lower revenue share than is reflective of their relative contribution to our total costs (assuming the above causal allocators) and shown in the residual cost recoveries inherent in our 2018-19 tariffs below.

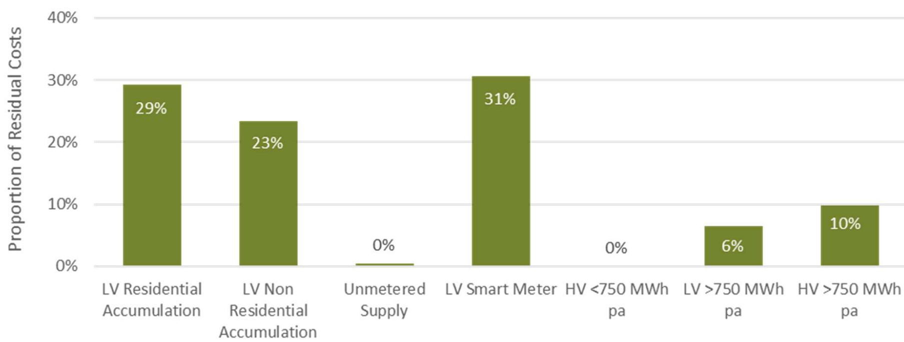
Figure 2. Residual cost recovery share by tariff (legacy 2018-19)



Our forecast revenue is falling compared to the current regulatory control period, providing an opportunity for revenue alignment without price increases. Falling revenue means we have been able to propose a better sharing of our costs by reducing the revenue collected from residential and non-residential customers', and increasing the relative share of our larger customers.

Figure 3 shows the resulting recovery of residual costs from each tariff in 2019-20.

Figure 3 Residual cost recovery share by tariff (proposed 2019-20)



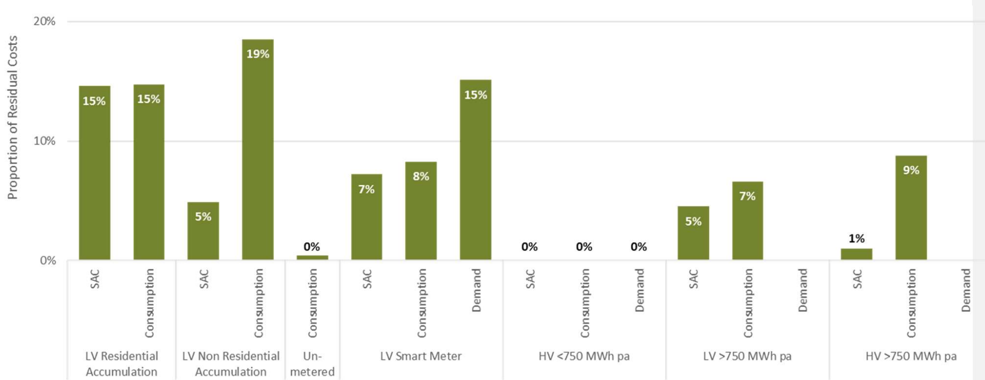
3.5.7 Revenue recovery through non-distortionary charging parameters

We have designed our tariffs to recover residual costs in a way that:

- minimises distortions to efficient price signals, by seeking to have demand tariffs at least as high as our LRMC estimates, or below these where we have needed to manage bill impacts; and
- considers the impact of residual costs on customer bills, and whether these bill impacts will distort usage decisions (including whether the Pricing Order will prevent bill impacts).

To achieve this, we preference recovery of residual costs from fixed system access charges and demand charges rather than energy charges, where this can be achieved whilst managing bill impacts. The outcome of this for our proposed 2019-20 tariffs is shown below.

Figure 4 Residual cost recovery share by tariff component in 2019-20



3.6 Considering customer impacts of tariffs

Managing customer impacts was a key focus of our tariff design, and informed how we designed our customer engagement on pricing issues as required by rule 6.18.5(h). Uniquely within the NEM, the Pricing Order means we have two distinct types of retail customers with differing price impacts.

3.6.1 Customers who use less than 750MWh per year per NMI

Most of our 85,000 customers, comprising households and small to medium businesses, are subject to retail pricing protection, so our TSS pricing decisions will not directly affect their retail electricity bills.

Our engagement with these customers still tested their understanding and acceptability of our tariff design thinking and draft plans, and relevantly found that these customers understood their bills will be unaffected by changes we make to our tariffs to become more cost reflective.

This meant we could immediately structure our tariffs to cost reflective structures with cost reflective tariff levels for customers with smart meters without creating bill shock. This approach was supported by our CAC.

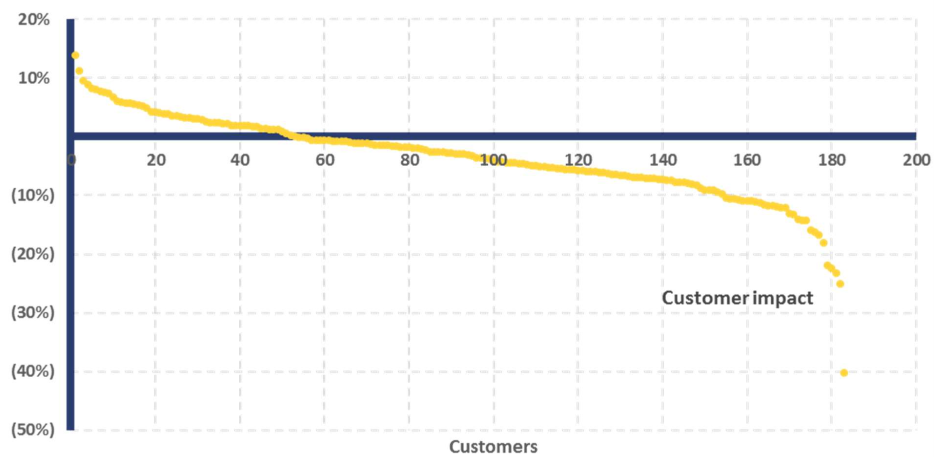
Notwithstanding this, we have sought to ensure our LV smart meter tariff does not create a disincentive to be on that tariff relative to the equivalent residential and non-residential accumulation meter tariffs.

3.6.2 Customers who use greater than 750MWh per year per NMI

Our 200 largest energy users generally see our network tariffs as a separate line item on their retail bill. Our network prices will directly affect these customers. We sought to manage our tariff changes to minimise customer impacts and our engagement with these customers focussed on specific tariff changes, options, and impacts for these customers and ensure that as a group this cohort of customers are no worse off.

Our large user tariff impact analysis for the first year of our 2019-24 regulatory control period relative to 2018-19 (assuming constant demand) is shown in the figure below. This shows the network bill impact, which would be lessened when considered at a retail bill level.

Figure 5: Large user customer bill impact analysis



It is estimated that nearly 150 customers will receive price reductions under the proposed network tariffs. These reductions mainly relate to reduced energy (kWh) charges.

However, there are a number of customers that will have price increases. The reasons for this are mixed. Some of the large use customers face price increases due to the current declining block tariffs being reduced to a single anytime rate. Others face price increases due to increases in kVA related charges (i.e. demand), while others have increases in fixed charges as we move from the number of meters to NMIs.

3.6.3 Customer network bill impacts

The following table shows indicative network bill impacts for our different illustrative customer types. These impacts are based on our proposed revised revenue forecasts and the indicative tariffs set out in our revised TSS. They do not account for the effects of the Pricing Order or retail bills.

Table 11 Movement in customers' network bills 2018-19 to 2019-20 (excluding GST)

Customer Type	Network Bill		Bill Movement	
	2018-19	2019-20*	$	%
Small Residential - average energy - Accumulation Meter (8500 kWh pa)	1,093	875	(219)	(20%)
Small Residential - average energy - Smart Meter (8500 kWh pa)	1,093	1,022	(71)	(7%)
Large Residential Accumulation Meter (15,000 kWh pa)	1,808	1,318	(489)	(27%)
Large Residential Smart Meter (15,000 kWh pa)	1,808	1,380	(427)	(24%)
Non-Residential Accumulation Meter (30,000 kWh pa)	3,407	3,425	18	1%
Smart Meter (30,000 kWh pa) (non-residential)	3,407	2,342	(1,065)	(31%)
Industrial (1,000,000 kWh pa - LV)	90,547	92,579	2,033	2%
Large Industrial (6,000,000 kWh pa - HV)	290,369	271,783	(18,586)	(6%)

* Includes ACS Metering

3.7 Ensuring that tariffs can be understood

In developing our TSS we sought to ensure that the new tariff charging parameters for particular tariff classes, and our changes to structures and charging arrangements (such as the peak charging window), were understood by customers who faced these bill impacts. We consulted in our phase 1 and phase 2 engagement program with residential and small non-residential customers about the concept of demand charging and our time of use charging window. We did the same with our large user forum in addition to a dedicated session on power factor correction ~~on our~~relating to the possibility of a new excess kVAr charge, and our November 2018 retailer forum.

The tariff changes that better simplify our tariffs to help ensure they are reasonably capable of being understood by retail customers, as required by rule 6.18.5(i), are as follows:

- We have simplified our tariff structures to remove blocks and have flat rate energy and demand charges:
  - flat rates are easier for customers to understand; and
  - the flat rate tariff option was the most preferred option tested at our large

user forum.

- We have simplified our tariffs by removing off-peak demand charges:
  - this supports a simpler message for our customers that capacity in off-peak periods is encouraged by being free; and
  - this was welcomed at our large user forum.
- We have extended the off-peak period:
  - this now includes an additional 39 hours a week and weekends, which was welcomed at the large user forum and considered simpler because it aligns with retailers' treatment of weekends as off-peak; and
  - for LV connected less than 750MWh tariff class customers with a smart meter, the off-peak period also includes the six months between 1 October and 31 March.
- We have retained simplicity in our tariff schedule by not having a menu of opt in tariffs.
- ~~We have sought to support customer understanding of the excess kVAr charge by:~~
  - ~~having dedicated consultation sessions on it at our large user forum and at the first CAC;~~
  - ~~delaying its introduction to 2021-22 to better allow customers to understand and prepare for this change, in response to large user feedback;~~
  - ~~publishing a fact sheet on this charge; and~~
  - ~~assigning account managers to our large users to help them manage the transition and their preparedness for this charge.~~

Power and Water, in its initial proposal~~Initial Regulatory ProposalIRP~~ and revised proposal~~Revised Regulatory ProposalRRP~~ put forward the proposal that from 2021-22 we ~~sh~~would introduce a charge relating to customer~~'~~s' excess kVAr. That is, introduce a financial incentive for customers to ensure that their power factors are meeting minimum requirements as specified in our Network Technical Code.

After feedback from stakeholders and the AER, Power and Water have withdrawn this proposed charge from the proposed TSS. We will continue to investigate and work with stakeholders on how to encourage customers to improve their power factors, including the introduction of financial incentives through a tariff trial.

Power and Water notes that the NT NER provides provisions to introduce a charge under trial conditions using sub-threshold tariffs available under clause 6.18.1C. It may be appropriate for an excess kVAr charge, at some stage during the determination period, to be introduced in accordance with these conditions.

Consistent with our stakeholder engagement and resulting commitments to our customer arising from that engagement, we would not consider introducing a trial before 1 July 2021.

3.8 Indicative tariffs

The following sections outline the indicative tariffs for 2019-20. We note that these indicative tariffs will necessarily change:

- during the course of the AER's review process because our proposal reflects a placeholder averaging period for certain rate of return parameters; and
- in preparing for our 2019-20 annual tariff application based on operation of the annual unders and overs true-ups in the revenue cap.

Our indicative prices over the 2019-24 regulatory control period are also available at Appendix A to our TSS.

3.8.1 LV less than 750MWh tariff class

The following table sets out the indicative 2019-20 tariffs by charging parameter for our four tariffs available for customers with annual consumption of less than 750MWh per annum per NMI.

Table 12 less than 750MWh per annum per NMI indicative tariffs (2019-20) (excluding GST)

System Availability Charge	($/day)
Dollars per day per NMI – LV Residential Accumulation[1]	0.640
Dollars per day per NMI – LV Non Residential Accumulation[1]	1.350
Dollars per day per NMI – LV Smart Meter[1]	1.350
Dollars per day per NMI – HV <750MWh[1]	1.350
Energy Charges	(¢/kWh)
LV Residential Accumulation	6.82
LV Non Residential Accumulation	9.57
LV Smart Meter	1.54
HV <750MWh	1.54
Unmetered Supply	**(¢/kWh)**
Unmetered Supply	5.51
Demand Charges	**($/kVA)**
LV Smart Meter Peak[2]	20.51
HV Peak <750MWh[3]	9.50
~~kVAr Charge~~	~~**($/kVAr)**~~
~~>40MWh LV Smart Meter~~	—
~~>40MWh HV~~	—

[1] National Meter Identifier which is allocated to each customer's connection.

[2] The peak period rates apply to usage between 12 noon and 9:00pm on any weekday, including public holidays from 1 October through 31 March. Off-peak period rates apply at other times.

[3] The peak period rates apply to usage between 12 noon and 9:00pm on any weekday, including public holidays. Off-peak period rates apply at other times.

3.8.2 LV greater than 750MWh tariff class

The following table sets out the indicative 2019-20 tariffs for each charging parameter for LV greater than 750MWh tariff class customers.

Table 13 LV greater than 750MWh per annum per NMI indicative tariffs (2019-20) (excluding GST)

Low Voltage Connected Customers with consumption above 750MWh per year per NMI				
	$/day per NMI	$/kVA Peak[1]	¢/kWh anytime	~~kVAr $/kVAr~~
System availability charge	70.00			-
Plus charges related to monthly demand		11.000		-
Plus charges related to energy metered			2.550	-
~~Plus charges related to excess kVAr~~	-	-	-	—

[1] The peak period rates apply to usage between 12noon and 9:00pm on any weekday, including public holidays. Off-peak kVA will not be charged.

3.8.3 High Voltage greater than 750MWh tariff class

The following table sets out the indicative 2019-20 tariffs for each charging parameter for our HV greater than 750MWh tariff class customers.

Table 14 HV greater than 750MWh per annum per NMI indicative tariffs (2019-20) (excluding GST)

High Voltage Connected Customers with consumption above 750MWh per year per NMI				
	$/day per NMI	$/kVA peak[1]	¢/kWh anytime	~~kVAr $/kVAr~~
System availability charge	70.00			-
Plus charges related to monthly demand		8.270		-
Plus charges related to energy metered			2.550	-
~~Plus charges related to excess kVAr~~	-	-	-	—

[1] The peak period rates apply to usage between 12noon and 9:00pm on any weekday, including public holidays. Off-peak period rates apply at other times. Off-peak kVA will not be charged

4 Alternative control services

Power and Water's IRP split Alternative Control Services (ACS) into fee based, quoted services and metering service consistent with the AER's proposed service classification. These services, except metering services are, one off, customer specific services. This chapter explains how these have been updated in our RRP. Note all fees shown in this chapter exclude GST (unless otherwise stated).

4.1 Fee-based and quoted services

4.1.1 Overview

This section focuses on fee based and quoted services.

Fee based and quoted services fees are designed to achieve cost recovery for each one-off instance of the requested service (i.e. rather than require ongoing payment). Power and Water has undertaken a study to estimate the cost of providing each service, which includes, direct labour, materials, vehicles, corporate overhead and network overheads. There is no profit provision included. The AER's Draft Decision has endorsed this approach.

Our proposed fees in this RRP are equal to the resulting cost per service. The names and descriptions of the proposed fee based and quoted services are set out in section 5 of our TSS.

Total revenue is estimated to be around $4.0 million per annum (fee based) and $2.3 million per annum (quoted services) (2019-20).

Over half of the fee based revenue is forecast to come from disconnection and reconnection services ($2.3 million per annum). Around 50% of the quoted services revenue is forecast to come from *Rearrangement and Connection of network assets at customer requests* ($1.1 million) and a third from *Access permits, oversight and facilitation ($0.7 million)*.

4.1.2 IRP submission

The major changes from Power and Water's current approach for fee based and quoted services to that proposed in the IRP are:

- Inclusion of network safety services;
- Inclusion of planned interruption – customer request;
- Inclusion of training to third parties for network related access;
- Moving normal connections and disconnects services from Standard Control Charges (SCS) to ACS. Note that connections and disconnections relating to non-payment are already an ACS fee; and
- Removal, consolidation and inclusion of new fees.

4.1.3 Stakeholder feedback and AER Draft Decision

Submissions

Jacana's submission stated that it receives consistent feedback from its customers regarding the costs of reconnecting their electricity supply after hours and questioned the fairness of the amount of the reconnection fee for after business hours connections and why that fee is applied from 3:00 pm (as opposed to 4:00 pm in other jurisdictions).

In light of stakeholder feedback, Power and Water requested the AER stay its determination on ACS fees so that we could further review and amend our proposed fees.

The AER's Draft Decision[11]:

- Confirmed the classifications of services to be included as ACS and the pricing cap decision;
- Stated that the changes reduced complexity and provide for a simplified fee structure;
- Imposed minor modification to hourly labour rates and escalations resulting in slightly higher fees (about 2.45%);
- Accepted the proposed service structures, but not the actual fees; and
- Accepted the proposed quoted service labour rates in principle subject to correction of an inflation adjustment calculation error on the basis of our labour rates being within the benchmarking conducted by its consultant, Marden Jacobs.

With regard to the changes to service structures, there were a number of changes relating to reconnection and disconnection services.

The AER accepted our proposal to merge the fee for disconnecting / reconnecting CT meters with standard reconnection and disconnection fees due to the limited number of instances involving CT meters. This results in a simpler fee structure for customers.

Additionally, the final Framework and Approach removes standard reconnections and disconnections from the standard control charges and move these into alternative control charges. This is consistent with the current treatment of reconnections and disconnections for non-payment, which are currently classified as an alternative control charge. For simplicity, the IRP proposed that these two fees be merged into a single reconnection charge and disconnection charge, irrespective of the reason for the reconnection and disconnection.

The AER's main concern regarding the IRP related to the proposed level of the after-hours fee (IRP proposed $563 in 2019-20), which it considered to be too high.

The AER stated that it will allow Power and Water to complete our holistic review of our proposed fee based and quoted services fees. Updated fee based and quoted services information must be included in our RRP.

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[11] AER, Draft Decision – Power and Water Corporation Distribution Determination 2019 to 2024. Attachment 15: Alternative Control Services, section 1.5, page 15-6.

Our RRP addresses both these matters.

Further engagement

The CAC was briefed on 23 October 2018 on the proposed changes and considered that they were positive, especially the change in cut-off time for after-hour reconnections and the reduction in the after-hour reconnection fee.

On 8 November 2018 we held an energy stakeholder forum with retailers, and interested stakeholders to discuss TSS and ACS issues and implementation plans ahead of the 1 July 2019 start date. At this forum we consulted stakeholders on our proposed updated list of fee-based services and tested the definitions and eligibility arrangements. This process has allowed us to test and refine the definitions and eligibility arrangements, and ensure the list is comprehensive and administratively simple to meet retailers' and customers' needs during 2019-24.

The list and definitions provided in chapter 5 of our revised TSS reflects the outcome of this engagement.

4.1.4 Changes in our RRP

Disconnection and Reconnections

After hour services - background

Most disconnections and reconnections are scheduled. However, there are also many requests that are priority requests (same day). Most priority requests for reconnections received by our metering team prior to 3:00 pm are actioned the same day. Power and Water's Customer Contract currently states that requests to Power and Water provided prior to 3:00 pm, for reconnection, will be actioned by the end of the next business day. However, requests provided after 3:00 pm will be actioned by the end of the second business day.[12]

If the customer, after 3:00 pm, requests a reconnection after-hours, they currently get charged an additional charge of $622. There are currently around 80 requests per year for after-hour reconnections.

After hour services - timing

We now propose that the 3:00 pm same day deadline be extended to 4:00 pm from 1 July 2019. We expect that this would, under normal circumstances provide Power and Water (and its contractors) with sufficient time to reconnect customers prior to 6:00 pm. This also responds to Jacana's feedback and aligns with other networks.

Requests received by Power and Water after 4:00 pm, for same day reconnection will be based on an after hour reconnection fee.

[12] The Electricity Industry Performance Code, established by the Utilities Commission of the Northern Territory, imposes a guaranteed service levy (GSL) scheme (clause 4) onto Power and Water's network business. In particular there is an obligation for us to reconnect customers within 24 hours. In 2019-20, the GSL payment to impacted customers is $56.50 per instance.

While we will endeavour to provide an after-hours service, there may be circumstances where this is not possible or safe. In these circumstances we would complete the service the next business day, and a standard reconnection charge would apply.

After hour services - renaming

In our RRP, this service has been renamed to reflect that this fee now solely relates to reconnections. It is proposed to rename "after hours call out" to "Reconnection – After Hours". As outlined below there is a new, separate, after hour surcharge fee that will cover other circumstances.

After hour reconnection services – change in fee

By isolating out after-hour reconnections from other after-hour work the fee is proposed to be set at $123. Other after-hour work is generally more complex and requires Power and Water crews, rather than contractors. The estimated cost for reconnections – after hours is now predominantly based on the cost of contractors.

Disconnection and reconnections with communication capability

The cost difference of physically reconnecting and disconnecting meters, at $70 (IRP), compared to the cost of remotely reconnecting and disconnecting smart meters, at $9 (IRP), is significant. In the IRP we indicated that there should be a different fee for reconnecting and disconnecting smart meters (remotely) and accumulation meters (physical) which would provide incentives for customers to switch to smart meters.

After further review of the actual incentive and control customers have over their choice of meter and to ensure consistency with other metering fees, it is now proposed to retain a single fee.

This is consistent with the reasoning applied to our proposed metering service provision charges (for Types 1 – 6 meters) as approved by the AER in its Draft Decision. The AER observed:

> *We consider that not differentiating between customers with smart meters and those without is appropriate for the 2019–24 regulatory control period. Given the greater capex expenditure on smart meters is offset by reduced opex expenditure from reduced manual meter reading, the per meter costs of smart meters and accumulation meters will not be significantly different during the 2019–24 regulatory control period.*
>
> *While a smart meter offers greater functionality, we consider that since customers will not be choosing their meter type (unless they pay a fee to have a smart meter installed earlier than scheduled) it is more equitable that they not be charged differently for that meter type. This is what Power and Water has proposed and it is consistent with the existing metering cost recovery arrangements.*[13]

[13] AER, Draft Decision – Power and Water Corporation Distribution Determination 2019 to 2024. Attachment 15: Alternative Control Services, p.15-25.

We recognize that customers have limited choice over when their meter gets upgraded from an accumulated meter to a smart meter under our new and replacement smart meter rollout. And the decision to move to smart meters is due to system-wide benefits. Thus all customers should benefit from the lower operational costs arising from smart meters. Our RRP approach supports this by calculating a charge based on the weighted forecast of manual and remote reconnections and lowering prices to all customers as the smart meter rollout progresses.

As the ratio of smart meters increases across the fleet of meters it is estimated that the average cost of reconnecting and disconnecting will decrease. This is reflected in this RRP via a dedicated x factor for *Disconnection, Reconnection and Reconnection – after hours* which results in these fees reducing over the period as more smart meters are deployed.

New Fees

Our holistic review identified several additional fee-based alternative control services that are new market developments in the NT or were missed in the IRP. The resulting new fees added since the IRP are:

Prepayment vending charge

This fee based service is an administrative charge to the retailer. It relates to transactions with remote prepaid meters, such as applying additional credit.

Prepayment meter support charge

This fee based service covers the cost of Power and Water undertaking non-standard information requests from retailers relating to pre-paid meters.

Prepayment meter service fee

This quoted service relates to the administration and support of pre-paid meters. It includes the provision of technical support, training, trouble shooting, and staff support provided to retailers. Software licence charges will be on-charged according to customer requirements.

Solar PV assessment

Currently Power and Water undertake administration and assessment of proposed installation of solar photovoltaic (PV) systems. This includes processing the application, undertaking the engineering assessment (Class 3 and above) and developing an access agreement.

Class 1 and 2 assessments are smaller systems. Class 1’s are up to 7kVA for three phase systems. Class 2 include larger systems up to 30 KVA, but with a zero export.

Class 3 type installations are large installations up to 200kVA in Darwin and 100kVA in Alice Springs, Katherine and Tennant Creek.

Power and Water does not currently charge for the required administration undertaken for the installation of Class 1 and 2 PV systems. It is proposed that from 1 July 2019 that customers proposing the installation of Class 1 and 2 PV systems be charged for the administration undertaken by Power and Water, nominal 1 hour.

For larger PV assessments (Class 3 and above) assessments are currently classified as quoted and are charged. Class 3 Solar PV assessments are routine assessments and should have a standard charge. It is therefore appropriate to list Class 3 Solar PV assessments under the fee based service listing.

A review of actual time spent on the assessment indicates that nearly 9 hours is currently taken per Class 3 assessment. However, we will undertake a review of the process, with a target of reducing the time to 7.5 hours. Thus it is proposed to base this fee on 7.5 hours of labour.

For more complex solar PV assessments, a quoted service will continue to be provided.

After hours surcharge

Our RRP includes an after-hours surcharge of 12~~5~~3% for all services (excluding reconnections) undertaken after-hours. This uplift is based on the additional labour costs incurred by Power and Water for staff working outside normal business hours. The surcharge relates to services provided after-hours during the working week.

Any service required on weekends or public holidays will be a quoted service.

Variation in specific rates

Installation of minor apparatus

Currently (2018-19), the charge for installation of minor apparatus is $502. Generally this service relates to the installation of polyloggers. Our IRP proposed a fee of around $76. Investigation of the large reduction found that the $76 is the cost of physically installing and removing the polyloggers. However, there is a significant level of analysis that is undertaken to interpret the data collected. Accounting for these costs results in the proposed RRP charge for this service being around $620.

Updates

Since our IRP, we have updated our cost and volume inputs to our fee based and quoted services.

Labour Rates

Fee based and quoted services in the IRP were based on the 2017-18 labour rates.

This submission continues with the 2017-18 labour rates which is consistent with an operating expenditure base year of 2017-18.

These labour rates have been escalated consistent with the SCS operating expenditure model. Specifically, they have been escalated by inflation and the BIS Oxford and DAE escalators.

Overhead

The overhead in the RRP is based on the 2017-18 AER-approved cost allocation model (CAM) model. Overhead has been divided by direct costs, resulting in a rate of 14% and 23%, for network and corporate overhead respectively. This rate has been applied to direct costs to generate a total price.

This is in contrast to the methodology used for the IRP, which sought to recover a specific amount of overhead in 2019-20 and allocated the overhead by forecast revenue per service.

Fee based and quoted services are forecast to collect around $1.7 million in overhead in 2019-20, which is similar to that collected in in 2017-18, but some $0.4 million more than the forecast for IRP. Coupled with an increase in allocation from quoted services to fee based services, there is a general increase in fee based services as compared to the IRP. However, most fee based fees remain below 2018-19 levels.

Benchmarks

The following table sets out the labour rates (including overhead) used for quoted services for 2019-20.

Table 15 Quoted Fees: labour rate including overhead per hour (excluding GST)

	IRP	AER Draft Decision	RRP	Marsden Jacobs Reasonable Maximum Rate
Admin	76.72	78.60	86.65	91.93
Technical	116.79	119.65	131.90	183.85
Engineering	136.95	140.30	154.67	171.59

It illustrates that while the labour rates per hour have increase due to a combination of correctly including escalation rates to 2017-18 labour costs and an increase in overhead per hour, the RRP labour rates remain below the Marsden Jacobs benchmark rates.

Volumes

The majority of fee based volumes have been updated for new data reported in our response to the annual Regulatory Information Notice (RIN) for audited 2017-18 actual data. However, where we have expanded or included new services we have included our best estimates, for example disconnections and reconnections.

With regard to quoted services the information arising from the RIN’s required additional modification to break the information into hours, which was undertaken based on total expenditure and labour rates.

4.2 Metering services

We welcome the AER’s approval of our smart meter rollout on a new and replacement basis and proposed structure for metering charges.

Our revised proposal addresses the concerns raised by the AER which had prevented it approving our proposed metering charges in the Draft Decision. A summary of our RRP changes is set out in the table below. Most of our cost input updates reflect those we have also applied to SCS services. The justifications for these are cross referenced accordingly.

Table 16 RRP updates to metering services proposal by Draft Decision issue

Issue	PWC response
Metering capex forecast – AER accepted the capex forecast with rate of return and inflation updates, and adjusting customer numbers for the AEMO growth forecast.	Retain our approved IRP capex forecast, updated for our RRP forecasts of: - rate of return[14] - inflation[15] - updated AEMO customer numbers forecast.
Current period RAB roll forward – AER rejected our use of more detailed asset classes, use of forecast depreciation and required that metering assets installed prior to 30 June 2019 need to be allocated to the mechanical meter or electronic meter classes which will have a standard life of 22.1 years and 24.3 years respectively.	Accept AER finding by adopting the AER's Draft Decision metering roll forward model and updating it with our 2017-18 actual metering capex.
Next period RAB roll forward – AER rejected our electronic meter standard life and proposed a standard life of 24.3 years for electronic meters.	Maintain IRP position to apply a standard life for the electronic meter class of 15 years, having regard for AEMO and AER precedent, not 24.3 years proposed by AER.
Metering base opex – AER accepted our base opex forecast.	Retain our approved IRP base opex forecast, updated for our actual 2017-18 RIN data.
Metering opex step changes – AER accepted approved 2 of the 3 positive step changes for new metering obligations, and approved our step change for metering savings arising from the smart meter rollout opex forecast. The rejected step change related to Southern Region metering technical staff.	Accept AER finding.
Labour escalation – AER substitutes wage index forecasts using DAE's forecast instead of PWC's forecast.	We have revised our IRP position consistent with our SCS approach. We have adopted the DAE forecast and average it with a new forecast for the NT prepared by BIS Oxford that we commissioned. The BIS Oxford forecast is provided at Attachment PWCR01.7.

[14] Explained in Chapter 6 of our RRP.
[15] Explained in Chapter 6 of our RRP .

5 Glossary of Terms

Term	Definition
ACS (charges)	Alternative Control Services
AEMO	Australian Electricity Market Operator
AER	Australian Electricity Regulator
CAPEX	Capital Expenditure
CCP	Consumer Challenge Panel
DNSP	Distribution Network Service Provider
GST	Goods and Services Tax
GW	GigaWatt
GWh	GigaWatt hour
HV	High Voltage
kV	KiloVolt
kVA	KiloVolt Amperes
kVAr	KiloVolt Amperes reactive
kW	KiloWatt
kWh	KiloWatt hour
LRMC	Long Run Marginal Cost
LV	Low Voltage
MVA	Megavolt ampere
MW	MegaWatt

MWh	MegaWatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
OPEX	Operating expenditure
PV	Photo Voltaic
Power and Water	Power and Water Corporation
RoLR	Retailer of Last Resort (Jacana Energy)
SCS (charges)	Standard Control Services
Smart meter	A meter that records energy based on its time of use
TSS	Tariff Structure Statement
WACC	Weighted Average Cost of Capital
UC	Utilities Commission