Attachment 10.01 – Tariff Structure Statement

Amended September 2019

Content

1 ABOUT THIS TARIFF STRUCTURE STATEMENT

1.1 Introduction

We submit this Tariff Structure Statement to the Australian Energy Regulator (AER) in accordance with the requirements of the National Electricity Rules (NER).

We also submit Explanatory Notes (Appendix A) explaining our reasons for proposing the tariff structures in this document and explaining how they comply with the National Electricity Rules.

This Tariff Structure Statement (TSS) is a revision of the statement we submitted with our Regulatory Proposal in April 2018 and responds to the AER's Draft Decision released on 1 November 2018 and feedback from customers.

This TSS has also been amended to include new Embedded Network (EN) tariffs from 1 July 2020. The amendment has been submitted to the AER in accordance with the NER.

The amended TSS contains Explanatory Notes to the Amendment (Appendix B) explaining our reasons for proposing the new tariffs and explaining how they comply with the NER.

1.2 Structure of this Tariff Structure Statement

This Tariff Structure Statement has the following sections:

- Section 2 presents our tariff classes and assignment policies.
- Section 3 presents our tariff structures and charging parameters.
- Section 4 summarises our approach to setting tariffs.
- Section 5 provides our indicative pricing schedule for the 2019-24 regulatory period.
- Section 6 provides a checklist identifying how the Tariff Structure Statement Rule Requirements are met.

The accompanying Explanatory Notes in Appendix A provide more detail on this Tariff Structure Statement including an overview of the changes, our network and customers, our customer consultation, our pricing reform, our pricing principles and our customer impacts.

1.3 Feedback

We welcome feedback from our customers and stakeholders. Please provide feedback to:

pricing@ausgrid.com.au or

Network Pricing Manager
Ausgrid
GPO Box 4009
Sydney NSW 2001

Customers may also comment via Ausgrid's Facebook page at www.facebook.com/Ausgrid or via twitter.com/Ausgrid.

2 TARIFF CLASSES AND ASSIGNMENT POLICIES

This section sets out the tariff classes we divide customers for direct control services into and the policies and procedures we will apply to assign customers to tariff classes. It also sets out the policies and procedures for assigning customers to tariffs within each class.

2.1 Tariff classes

Table 2.1 below summarises our five network tariff classes, and the individual tariffs in each tariff class. For the first time, we include a set of demand tariffs for residential customers and for non-residential customers with less than 40 MWh energy consumption a year.

Our amendment includes a set of embedded network (EN) tariffs for EN customers with more than 160 MWh energy consumption a year.

Table 2.1. Ausgrid's tariff class descriptions from 1 July 2019, amended with new tariffs* from 1 July 2020

Tariff Class	Definition	Primary Network Tariffs	Other Network Tariffs
Low Voltage	Applicable to separately metered low voltage (400V or 230V) connections, as measured at the metering point.	EA025 – Residential TOU EA111 – Residential demand (introductory) EA115 – Residential TOU demand EA116 – Residential demand EA225 – Small business TOU EA251 – Small business demand (introductory) EA255 – Small business TOU demand EA256 – Small business demand EA302 – LV 40-160 MWh EA305 – LV 160-750 MWh EA310 – LV >750 MWh EA327 – LV EN residential 160-750 MWh* EA337 – LV EN non-residential 160-750 MWh* EA347 – LV EN residential >750 MWh* EA357 – LV EN non-residential >750 MWh*	*Secondary* EA030 – Controlled load 1 EA040 – Controlled load 2 *Closed** EA010 – Residential non-TOU *closed* EA011 – Residential transitional TOU *closed* EA050 – Small business non-TOU *closed* EA051 – Small business transitional TOU *closed* EA316 – Transitional 40-160 MWh *closed* EA317 – Transitional 160-750 MWh *closed* EA325 – LV Connection (standby) *closed*
High Voltage	Applicable to any connection at high voltage (11kV) level, as measured at the metering point.	EA370 – HV Connection (system) EA380 – HV Connection (substation) EA367 – HV EN residential* EA377 – HV EN non-residential*	EA360 – HV Connection (standby) *closed* Individually calculated tariffs
Sub-transmission	Applicable to any connection at a sub-transmission voltage (132/66/33kV), as measured at the metering point.	EA390 – ST Connection (system) EA391 – ST Connection (substation) EA387 – ST EN residential* EA397 – ST EN non-residential*	Individually calculated tariffs

Tariff Class	Definition	Primary Network Tariffs	Other Network Tariffs
Unmetered	Applicable to any LV connection that is defined as an unmetered supply by Ausgrid in consultation with AEMO as per clause S7.2.3 (Item 5) of the Rules.	EA401 – Public lighting EA402 – Constant unmetered EA403 – EnergyLight	
Transmission	Applicable to any site that is connected to the electricity transmission network.	EA501 – Transmission tariff	Individually calculated tariffs

Note: *Closed* means only available for customers already assigned to the tariff. Transitional tariffs EA316 and EA317 will be closed during FY20 after the reassignments of existing customers reviewed for consumption thresholds is completed, to mitigate customer impacts, Once there are no more customers assigned to the closed tariff, we may remove this tariff from the pricing table at the annual pricing proposal. If there are no customers assigned to a tariff, we may also exclude it from the tariff table for the annual pricing proposal. * New tariffs in the amended TSS, to apply from 1 July 2020.

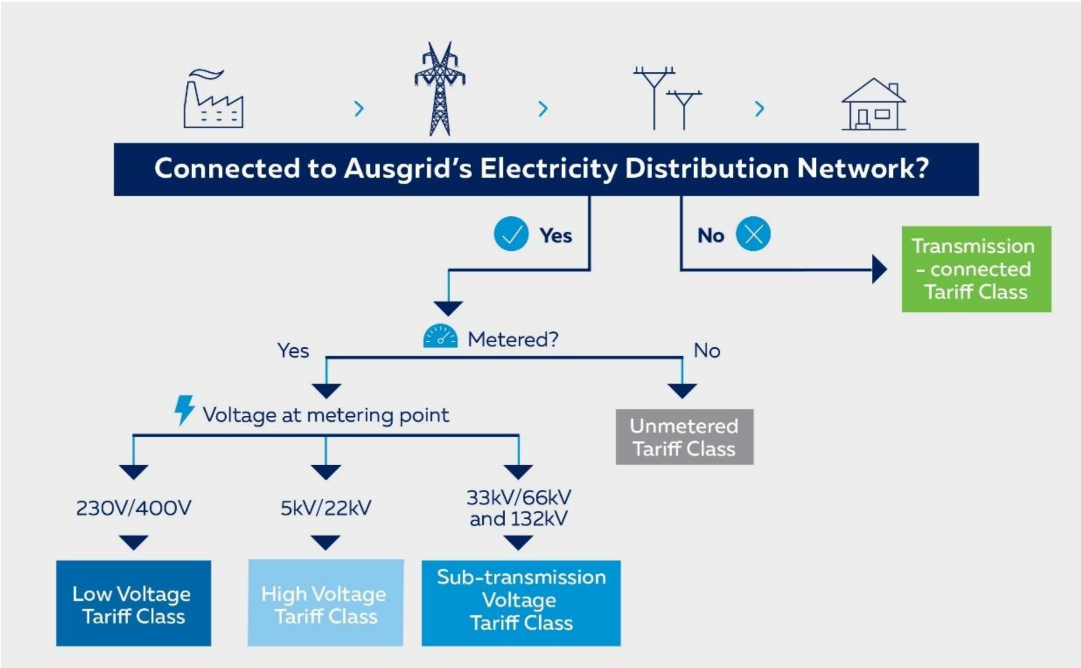
2.2 Assignment of customers to tariff classes

This section explains our proposed approach to assigning customers to tariff classes and to the individual tariffs in each tariff class. We describe our proposed tariffs and the charging parameters in Section 3.

Because our existing approach to assigning customers to tariff classes is consistent with the principles set out in the Rules, as previously approved by the AER, we are not proposing to make any changes to our existing approach.

Figure 2.1 shows our existing approach for assigning customers to a tariff class.

Figure 2.1. Overview of tariff class assignment procedure



2.3 Assignment of customers to a tariff within the tariff class

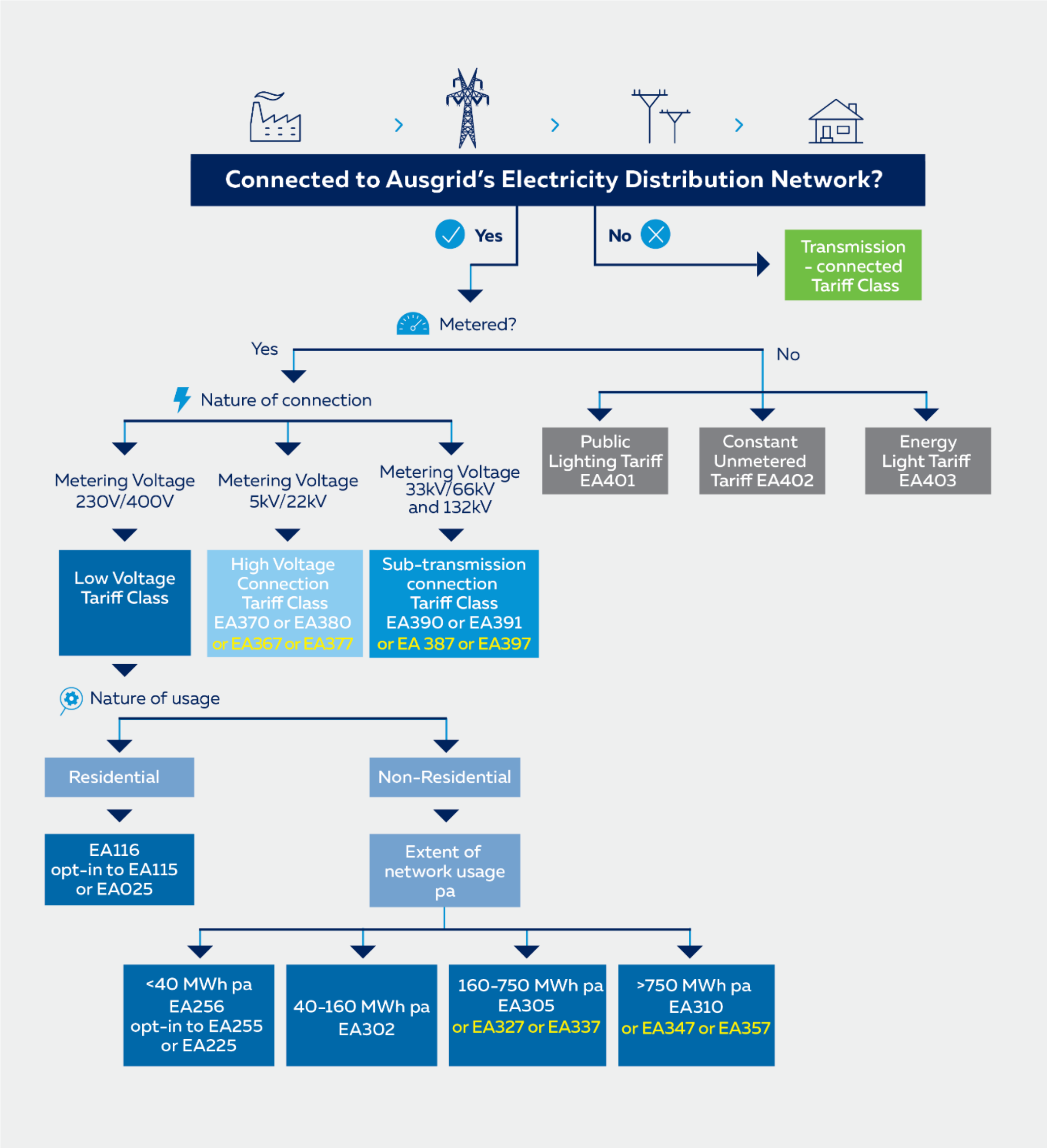
Our assignment of customers to a tariff within the tariff class reflects:

- the type of customer: new or existing, and residential or non-residential
- the type of meter the customer has: accumulation, interval or smart
- the tariff existing customers are assigned to
- the extent of usage, and
- the nature of usage for non-residential customers: end users or on-suppliers (embedded networks)

Figure 2.2 summarises our procedure for assigning new retail customers to a default tariff and for reassigning existing retail customers to another tariff.

We propose to assign retail customers to a tariff according to the nature of their connection, extent of their usage and metering type, consistent with the requirements of the Rules. We will continue to consider the customer bill impacts of assigning or reassigning customers to tariffs and depart from our proposed procedure to avoid unacceptable customer bill impacts from year to year, consistent with the customer impact principle in the Rules.

Figure 2.2. Ausgrid's default tariff assignment procedure for new customers



Definition of residential and non-residential customers

As defined in our ES7 Network Price Guide (Attachment 10.06), a residential customer is 'A customer that is assigned to the low voltage tariff class that uses their connection to Ausgrid's electricity network for domestic purposes (e.g. watching television, personal computer usage) except where the use of the network is predominantly for the purpose of obtaining a commercial financial gain.'

A non-residential customer is any customer not defined as a residential customer.

For the avoidance of doubt, strata house lights and common areas are classified as non-residential customers.

Definition of small business customers

In this Tariff Structure Statement, a Low Voltage non-residential customer with less than 40 MWh usage a year is a small business customer.

Definition of medium and large business customers

In this Tariff Structure Statement, a Low Voltage non-residential customer with more than 40 MWh usage a year is a medium or large business customer.

Definition of existing and new customers

A ‘new customer’ is defined as a newly energised connection, i.e., a connection that is energised on or after 1 July 2019.

An ‘existing customer’ is defined as a customer that exists at the time that Ausgrid undertakes the annual review and assessment for the 2019/20 pricing proposal.

Definition of embedded network

An embedded network is a network other than a registered TNSP or DNSP, which is connected to a distribution or transmission network at a parent connection point, and on-sells to customers connected at ‘child’ connection points (end users or other embedded networks).

An embedded network with any number of residential child connections is defined as a ‘residential EN’. Otherwise the EN is classified as non-residential.

2.3.1 Assignment in Low Voltage tariff class

Customers in the Low Voltage class are assigned to a tariff based on the nature of usage (residential or non-residential and for non-residential customers, whether an end user or an on-supplier), then, for non-residential customers, based on the extent of network usage a year, as shown in Figure 2.2.

Medium and large business customers

There is no change to assignment for non-residential customers with more than 40 MWh usage a year, except for customers that are on-suppliers (embedded networks). Newly energised or existing customers upgrading or modifying their connection from 1 July 2020, unless exempt by the AER’s Guidelines at the time of energisation or connection change, are assigned to new EN tariffs. The default tariff varies by the type of EN (residential or non-residential).

Residential and small business customers: Existing customers

Figure 2.3 summarises assignment for residential customers from 1 July 2019 by meter and tariff type. Figure 2.4 summarises assignment for non-residential customers with up to 40 MWh usage a year. At 1 July 2019, existing customers remain assigned to their current tariffs.

Figure 2.3. Assignment for residential customers from 1 July 2019

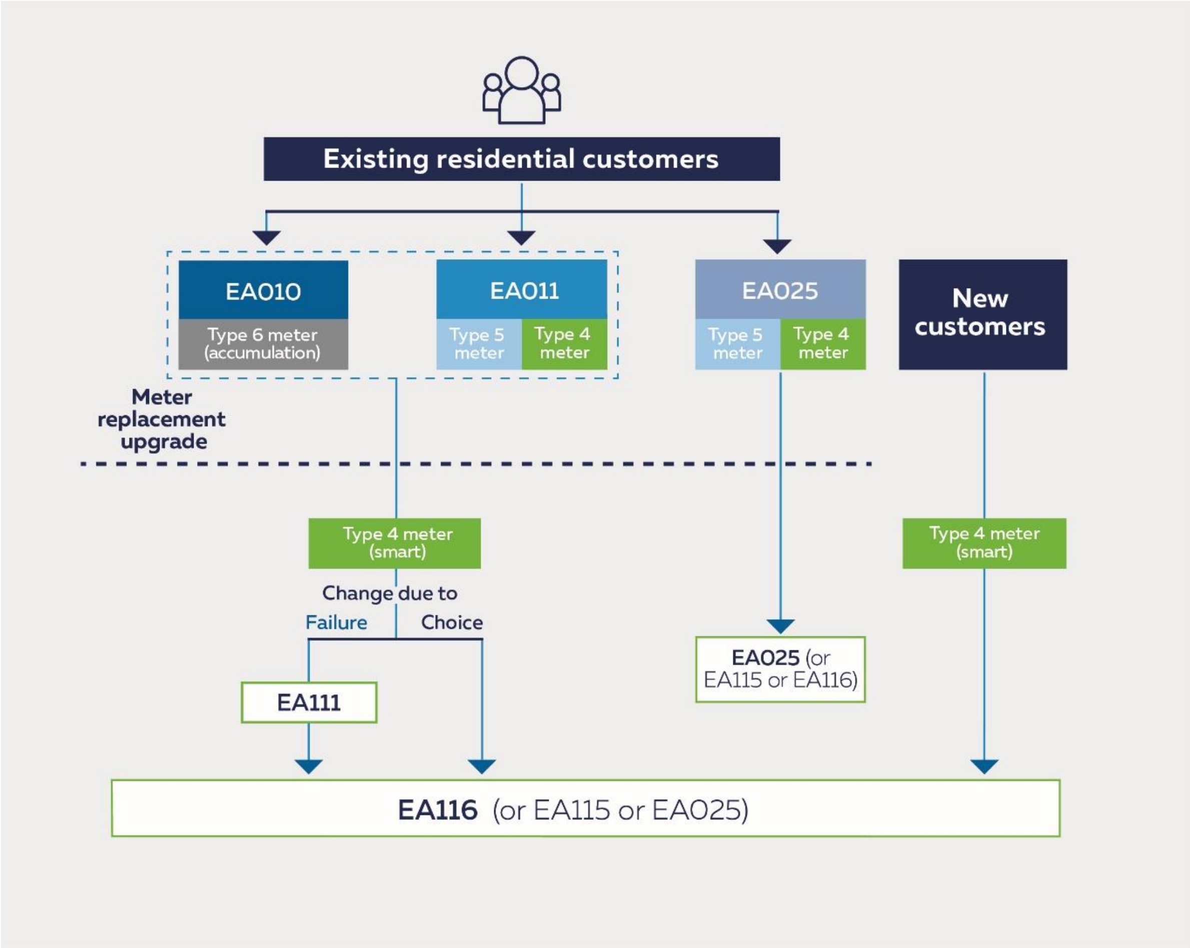
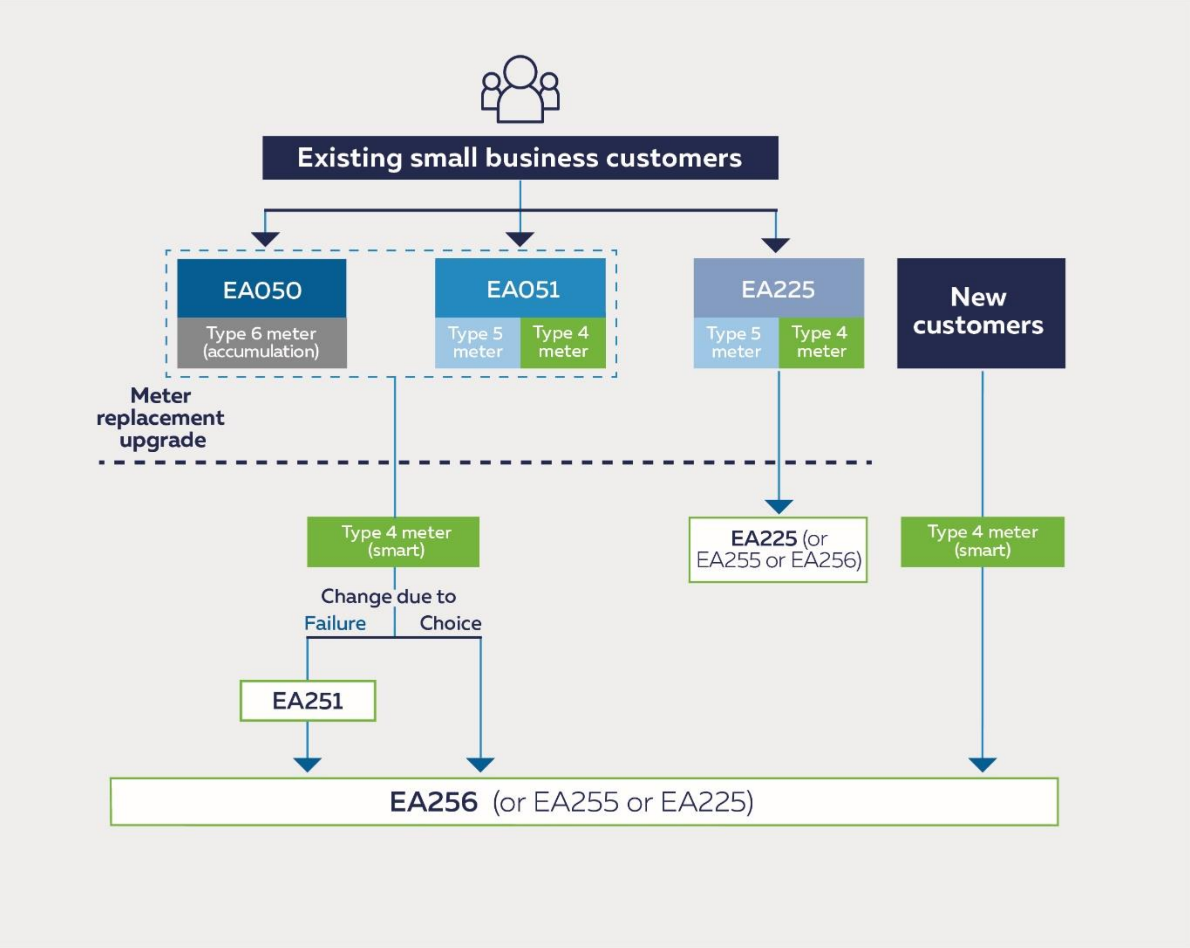


Figure 2.4. Assignment for small business customers from 1 July 2019



Residential and small business customers: Customers changing meter

Table 2.3 describes assignment for customers who change their meter to a Type 4 (smart) meter, depending on whether the customer initiates an action which results in a meter change or the change is due to meter failure (including network-driven meter family replacement). From 1 December 2017, under the Australian Energy Market Commission's Power of Choice set of regulations, any new or replacement meter will be a Type 4 (smart) meter.

Table 2.3. Existing customers – reassignment to tariffs after meter change after 1 July 2019

<table>
<tr><th>Meter change</th><th>Customer type</th><th>Existing tariff</th><th>Tariff after meter change</th><th>Options</th></tr>
<tr><td rowspan="4">Due to customer-initiated action</td><td rowspan="2">Residential</td><td>EA010, EA011</td><td>EA116 – Residential demand</td><td>EA115 – Residential TOU demand
EA025 – Residential TOU</td></tr>
<tr><td>EA025</td><td>EA025 – Residential TOU</td><td>EA115 – Residential TOU demand
EA116 – Residential demand</td></tr>
<tr><td rowspan="2">Small business</td><td>EA050, EA051</td><td>EA256 – Small business demand</td><td>EA255 – Small business TOU demand
EA225 – Small business TOU</td></tr>
<tr><td>EA225</td><td>EA225 – Small business TOU</td><td>EA255 – Small business TOU demand
EA256 – Small business demand</td></tr>
<tr><td rowspan="4">Due to meter failure</td><td rowspan="2">Residential</td><td>EA010, EA011</td><td>EA111 – Residential demand (introductory) for 12 months then EA116 – Residential demand</td><td>EA115 – Residential TOU demand
EA116 – Residential demand
EA025 – Residential TOU</td></tr>
<tr><td>EA025</td><td>EA025 – Residential TOU</td><td>EA115 – Residential TOU demand
EA116 – Residential demand</td></tr>
<tr><td rowspan="2">Small business</td><td>EA050, EA051</td><td>EA251 – Small business demand (introductory) for 12 months then EA256 – Small business demand</td><td>EA255 – Small business TOU demand
EA256 – Small business demand
EA225 – Small business TOU</td></tr>
<tr><td>EA225</td><td>EA225 – Small business TOU</td><td>EA255 – Small business TOU demand
EA256 – Small business demand</td></tr>
</table>

Note: Small business is a non-residential customer with up to 40 MWh usage a year.

Residential and small business customers: New connections after 1 July 2019

From 1 July 2019, new residential customers will be assigned to the new default tariff EA116 Residential demand, with the option to be reassigned to EA115 Residential TOU demand.

From 1 July 2019, new small business customers will be assigned to the new default tariff EA256 Small business demand, with the option to be reassigned to EA255 Small business TOU demand.

2.3.2 Assignment in High Voltage and Subtransmission tariff classes

Existing customers and new end-user customers in the High Voltage or Subtransmission tariff classes will be assigned to a default TOU capacity tariff following our tariff assignment procedure in Figure 2.2. Newly energised or existing customers that are on-suppliers (embedded networks) upgrading or modifying their connection from 1 July 2020, unless exempt by the AER's Guidelines at the time of energisation or connection change, are assigned to new EN tariffs. The default tariff varies by the type of EN (residential or non-residential).

If customers satisfy the eligibility criteria, we will reassign customers connected to our electricity transmission network to an individually calculated site-specific network tariff or, in some circumstances, a substation connected tariff, as part of our annual pricing process. Our policy on individually calculated tariffs is provided in our document ES7 Network Price Guide available on our website.

2.3.3 Principles

Principles for assignment, reassignment, notification and management include:

- We document and update procedures in our ES7 Network Price Guide available on our website.
- We may reassign a customer to another tariff if we become aware that an existing customer's characteristics have changed and it is no longer appropriate for the customer to remain assigned to the current tariff.
- We will notify a customer's retailer in writing of the tariff to which a customer has been assigned or reassigned, prior to the assignment or reassignment occurring.
- We will advise customers and retailers of the process for objecting to a proposed reassignment.
- Customers may be able to request a change to their network tariff within the same tariff class (such as to an available opt-out tariff) by applying through their retailer.
- When a customer's meter is replaced, the retailer should notify us of the change so we can assign the customer to an appropriate network tariff.

Attachment 10.02 describes our procedure for assignment (unchanged from our Initial Proposal).

Attachment 10.06 is our proposed amended ES7 Network Price Guide, to apply from July 2020.

3 STRUCTURES AND CHARGING PARAMETERS

This section sets out the structure of our tariffs and the charging parameters for each of our tariffs. Indicative prices for each year of the regulatory period are in Section 5.

3.1 Tariff structures and charging parameters

Table 3.1 below summarises all network tariffs by type of charging parameter. The four types of charging parameter are:

- network access charge
- energy consumption charge
- demand charge
- capacity charge.

The energy consumption and demand charges may vary by time of day and/or by season, with different time periods applied to residential and non-residential customers.

The definitions of time periods used in the charging parameters for the demand charge and Time of Use (TOU) energy consumption charge are summarised for residential customers and small business customers in Tables 3.2 to 3.6. Time periods for the capacity charge and TOU energy consumption charge for medium to large Low Voltage, High Voltage and Subtransmission business customers are presented in Tables 3.7 and 3.8.

Tables 3.9 to 3.13 in the following sections show the tariff structures and charging parameters for each of the five tariff classes:

- Low Voltage (LV) tariff class
- High Voltage (HV) tariff class
- Subtransmission (ST) tariff class
- Transmission tariff class
- Unmetered tariff class.

Table 3.1. Ausgrid's network tariffs by charging parameter from 1 July 2019

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	✓	✓							
	EA011	Residential transitional TOU *closed*	✓		✓	✓	✓				
	EA025	Residential TOU	✓		✓	✓	✓				
	EA111	Residential demand (introductory)	✓		✓	✓	✓	✓	✓		
	EA115	Residential TOU demand	✓		✓	✓	✓	✓	✓		
	EA116	Residential demand	✓		✓	✓	✓	✓	✓		
	EA030	Controlled load 1	✓	✓							
	EA040	Controlled load 2	✓	✓							
	EA050	Small business non-TOU *closed*	✓	✓							
	EA051	Small business transitional TOU *closed*	✓		✓	✓	✓				
	EA225	Small business TOU	✓		✓	✓	✓				
	EA251	Small business demand (introductory)	✓		✓	✓	✓	✓	✓		
	EA255	Small business TOU demand	✓		✓	✓	✓	✓	✓		
	EA256	Small business demand	✓		✓	✓	✓	✓	✓		
	EA302	LV 40-160 MWh	✓		✓	✓	✓			✓	
	EA305	LV 160-750 MWh	✓		✓	✓	✓				✓
	EA310	LV >750 MWh	✓		✓	✓	✓				✓
	EA316	Transitional 40-160 MWh *closed*	✓		✓	✓	✓			✓	
	EA317	Transitional 160-750 MWh *closed*	✓		✓	✓	✓				✓
	EA325	LV Connection (standby) *closed*	✓		✓	✓	✓				✓
	EA327	LV EN residential 16-750 MWh*	✓		✓	✓	✓				✓
	EA337	LV EN non-residential 16-750 MWh*	✓		✓	✓	✓				✓
	EA347	LV EN residential >750 MWh*	✓		✓	✓	✓				✓
	EA357	LV EN non-residential >750 MWh*	✓		✓	✓	✓				✓
High Voltage	EA360	HV Connection (standby) *closed*	✓		✓	✓	✓				✓
	EA370	HV Connection (system)	✓		✓	✓	✓				✓
	EA380	HV Connection (substation)	✓		✓	✓	✓				✓
	EA367	HV EN residential*	✓		✓	✓	✓				✓
	EA377	HV EN non-residential*	✓		✓	✓	✓				✓
Sub-	EA390	ST Connection (system)	✓		✓	✓	✓				✓

Tariff Class	Tariff Code	Tariff Name	Network	Energy consumption charge				Demand charge		Capacity charge	
transmission	EA391	ST Connection (substation)	✓		✓	✓	✓				✓
	EA387	ST EN residential*	✓		✓	✓	✓				✓
	EA397	ST EN non-residential*	✓		✓	✓	✓				✓
Unmetered	EA401	Public lighting		✓							
	EA402	Constant unmetered		✓							
	EA403	EnergyLight		✓							
Transmission	EA501	Transmission-connected	✓		✓	✓	✓				✓

Note: See Tables 3.2 to 3.13 for definitions of each charging parameter for each tariff. * New tariffs in the amended TSS, to apply from 1 July 2020.

Definition of time periods for residential customers

The time period definitions used in the charging parameters for the demand charge for residential customers are summarised in Table 3.2 below.

Table 3.2. Demand charge: charging windows for residential customers

Demand window	Time period definition
High season (8 months)	• From 2 pm to 8 pm on working weekdays during 1 November to 31 March (inclusive) – the 'summer months' • From 5 pm to 9 pm on working weekdays during 1 June to 31 August (inclusive) – the 'winter months'.
Low season (4 months)	• From 2 pm to 8 pm on working weekdays during 1 April to 31 May and 1 September to 31 October (inclusive) – the non-summer and non-winter months.

The time period definitions used in the charging parameters for the time of use energy consumption charge are summarised in Table 3.3 below.

Table 3.3. Energy consumption charge: TOU charging windows for residential customers

Time period	Time period definition
Peak period	• From 2 pm to 8 pm on working weekdays during 1 November to 31 March (inclusive) – the 'summer months' • From 5 pm to 9 pm on working weekdays during 1 June to 31 August (inclusive) – the 'winter months'.

Shoulder period	The shoulder period applies from 7 am to 10 pm every day, except where a peak period applies during that period.
	Specifically, it applies:
	• on all weekends and public holidays from 7 am to 10 pm
	• on working weekdays in the 'summer months':
	    ○ from 7 am to 2 pm and from 8 pm to 10 pm
	• on working weekdays in the 'winter months':
	    ○ from 7 am to 5 pm and from 9 pm to 10 pm
	• on working weekdays in the non-summer and non-winter months:
	    ○ from 7 am to 10 pm.

Off-peak period	All other times that are not Peak or Shoulder: 10 pm to 7 am.

Note: All times take into account daylight saving during the period gazetted by the NSW Government, generally from 3 am on the first Sunday in October to 2 am on the first Sunday in April.

Definitions for the two existing controlled load tariffs are summarised in Table 3.4 below.

Table 3.4. Time period definitions for controlled load tariffs

Controlled load	Time period definition
EA030 Controlled load 1	Supply is usually available for 6 hours duration between 10 pm and 7 am.
EA040 Controlled load 2	Supply is usually available for 16 hours a day including more than 6 hours between 8 pm and 7 am and more than 4 hours between 7 am and 5 pm.

Definition of time periods for small business customers

The time period definitions used in the charging parameters for the demand charge for small business customers are summarised in Table 3.5 below.

Table 3.5. Demand charge: charging windows for small business customers

Demand window	Time period definition
High season (8 months)	• From 2 pm to 8 pm on working weekdays during 1 November to 31 March (inclusive) – the 'summer months' • From 2 pm to 8 pm on working weekdays during 1 June to 31 August (inclusive) – the 'winter months'.
Low season (4 months)	• From 2 pm to 8 pm on working weekdays during 1 April to 31 May and 1 September to 31 October (inclusive) – the non-summer and non-winter months.

Note: Small business is a non-residential customer with up to 40 MWh usage a year.

The time period definitions used in the charging parameters for the Time of Use (TOU) energy consumption charge for small business customers are summarised in Table 3.6 below.

Table 3.6. Energy consumption charge: TOU charging windows for small business customers

Time period	Time period definition
Peak period	• From 2 pm to 8 pm on working weekdays during 1 November to 31 March (inclusive) – the 'summer months' • From 2 pm to 8 pm on working weekdays during 1 June to 31 August (inclusive) – the 'winter months'.

Shoulder period	The shoulder period applies from 7 am to 10 pm every working weekday, except where a peak period applies during that period.
	Specifically, it applies:
	• on working weekdays in the 'summer' and 'winter' months:
	    ○ from 7 am to 2 pm and from 8 pm to 10 pm
	• on working weekdays in the non-summer and non-winter months:
	    ○ from 7 am to 10 pm.

Off-peak period	All other times that are not Peak or Shoulder: 10 pm to 7 am on working weekdays all year, and 24 hours on all weekends and public holidays all year.

Note: All times take into account daylight saving during the period gazetted by the NSW Government, generally from 3 am on the first Sunday in October to 2 am on the first Sunday in April.

Definition of time periods for medium to large Low Voltage, High Voltage and Subtransmission customers

The time period definitions used in the charging parameters for the capacity charge for medium to large Low Voltage, High Voltage and Subtransmission business customers are summarised in Table 3.7.

Table 3.7. Capacity charge: charging window for medium to large Low Voltage, High Voltage and Subtransmission business customers

Capacity window	Time period definition
All year round	• From 2 pm to 8 pm on working weekdays.

Note: Medium to large Low Voltage business customer is a non-residential customer with more than 40 MWh usage a year.

The time period definitions used in the charging parameters for the consumption charge are summarised in Table 3.8.

Table 3.8. Energy consumption charge: TOU charging windows for medium to large Low Voltage, High Voltage and Subtransmission business customers

Time period	Time period definition
Peak period	• From 2 pm to 8 pm on working weekdays during 1 November to 31 March (inclusive) – the 'summer months' • From 2 pm to 8 pm on working weekdays during 1 June to 31 August (inclusive) – the 'winter months'.

Shoulder period	The shoulder period applies from 7 am to 10 pm every working weekday, except where a peak period applies during that period.
	Specifically, it applies:
	• on working weekdays in the 'summer' and 'winter' months:
	    o from 7 am to 2 pm and from 8 pm to 10 pm
	• on working weekdays in the non-summer and non-winter months:
	    o from 7 am to 10 pm.

Off-peak period	All other times that are not Peak or Shoulder: 10 pm to 7 am on working weekdays all year, and 24 hours on all weekends and public holidays all year.

Note: All times take into account daylight saving during the period gazetted by the NSW Government, generally from 3 am on the first Sunday in October to 2 am on the first Sunday in April.

3.2 Proposed charging parameters

The following sections outline the proposed charging parameters for the tariffs within each tariff class. The proposed prices for each of the parameters for each year of the regulatory period are presented in Section 5.

3.2.1 Low Voltage tariff class

Table 3.9 summarises the charging parameters for the tariffs in the Low Voltage tariff class including six new tariffs from 1 July 2019. The three new residential demand tariffs and the three new small business demand tariffs each have six charging parameters including two demand charges. Section 5 shows the indicative prices for the charging parameters for all tariffs. Some parameters are set at the same price level, resulting in either a flat energy consumption charge or a flat demand charge. Price levels for charging parameters vary for different tariffs.

Table 3.9. Low Voltage tariff class – charging parameters

Tariff type	Component*	Measure	Charging parameter*
Closed EA010 Residential non-TOU, EA050 Small business non-TOU	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Flat	c/kWh	Network use of system charge for energy consumed anytime during the day
EA025 Residential TOU, EA225 Small business TOU *Closed* EA011 Residential transitional TOU, EA051 Small business transitional TOU	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period*
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period*
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period*
EA116 Residential demand, EA256 Small business demand EA115 Residential TOU demand, EA255 Small business TOU demand EA111 Residential demand (introductory), EA251 Small business demand (introductory)	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period*
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period*
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period*
	Demand charge – High season	c/kW/day	Network use of system charge applied to the maximum kW demand[1] over any half hour interval in the demand window in a High season month*

Tariff type	Component*	Measure	Charging parameter*
	Demand charge – Low season	c/kW/day	Network use of system charge applied to the maximum kW demand[1] over any half hour interval in the demand window in a Low season month*
EA302 LV 40-160 MWh pa *Closed* EA316 Transitional 40-160 MWh pa	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period#
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period#
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period#
	Capacity charge – Peak	c/kW/day	Network use of system charge for the maximum kW demand[1] over any half hour interval between 2 pm and 8 pm on a working weekday in the previous 12 months
EA305 LV 160-750 MWh pa, EA310 LV >750 MWh pa EA327 LV EN residential 160-750 MWh* EA337 LV EN non-residential 160-750 MWh* EA347 LV EN residential >750 MWh* EA357 LV EN non-residential >750 MWh* *Closed* EA317 Transitional 160-750 MWh pa EA325 LV Connection (standby),	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period#
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period#
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period#
	Capacity charge – Peak	c/kVA/day	Network use of system charge for the maximum kVA demand[1] over any half hour interval between 2 pm and 8 pm on a working weekday in the previous 12 months
EA030 Controlled load 1, EA040 Controlled load 2	Network access charge	c/day	Fixed daily charge

Tariff type	Component*	Measure	Charging parameter*
	Energy consumption charge	c/kWh	A secondary network use of system charge that applies to separately metered loads, only available with a primary network use of system tariff

Note: [1] Demand is based on the highest energy consumption recorded in a 30-minute interval.
*See Tables 3.2 and 3.3 for definitions of peak, shoulder and off-peak periods for energy consumption charges, and time periods for demand charges for residential tariffs, and Tables 3.5 and 3.6 for small business tariffs.
#See Table 3.8 for definitions of peak, shoulder and off-peak periods for energy consumption charges for medium to large business customer tariffs (non-residential > 40 MWh usage a year).

* New tariffs in the amended TSS, to apply from 1 July 2020.

3.2.2 High Voltage tariff class

Table 3.10 summarises the charging parameters for the two tariffs in the High Voltage tariff class.

Table 3.10. High Voltage tariff class – charging parameters

Tariff type	Components	Measure	Charging parameter
EA370 HV Connection (system), EA380 HV Connection (substation) EA367 HV EN residential* EA377 HV EN non-residential* *Closed* EA360 HV Connection (standby)	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period*
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period*
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period*
	Capacity charge – Peak kVA	c/kVA/day	Network use of system charge applied to the maximum kVA demand[1] recorded over any half hour interval between 2 pm and 8 pm on a working weekday in the previous 12 months

Note: See Table 3.8 for definitions of peak, shoulder and off-peak periods.
[1] Demand is based on the highest energy consumption recorded in a 30-minute interval.

* New tariffs in the amended TSS, to apply from 1 July 2020.

3.2.3 Subtransmission tariff class

Table 3.11 summarises the charging parameters for the two tariffs in the Subtransmission tariff class.

Table 3.11. Subtransmission tariff class – charging parameters

Tariff type	Component	Measure	Charging parameter
EA390 ST Connection (system), EA391 ST EA387 ST EN residential* EA397 ST EN non-residential* Connection (substation)	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period*
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period*
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period*
	Capacity charge – Peak kVA	c/kVA/day	Network use of system charge applied to the maximum kVA demand[1] recorded over any half hour interval between 2 pm and 8 pm on a working weekday in the previous 12 months

Note: See Table 3.8 for definitions of peak, shoulder and off-peak periods.
[1] Demand is based on the highest energy consumption recorded in a 30-minute interval.

* New tariffs in the amended TSS, to apply from 1 July 2020.

3.2.4 Transmission tariff class

Table 3.12 summarises the charging parameters for the single tariff in the Transmission tariff class.

Table 3.12. Transmission tariff class – charging parameters

Tariff type	Component	Measure	Charging parameter
EA501 Transmission connected	Network access charge	c/day	Fixed daily charge
	Energy consumption charge – Peak	c/kWh	Network use of system charge for energy consumed during the peak period*
	Energy consumption charge – Shoulder	c/kWh	Network use of system charge for energy consumed during the shoulder period*
	Energy consumption charge – Off-peak	c/kWh	Network use of system charge for energy consumed during the off-peak period*
	Capacity charge – Peak kVA	c/kVA/day	Network use of system charge applied to the maximum kVA demand[1] recorded over any half hour interval between 2 pm and 8 pm on a working weekday in the previous 12 months

Note: See Table 3.8 for definitions of peak, shoulder and off-peak periods.
[1] Demand is based on the highest energy consumption recorded in a 30-minute interval.

3.2.5 Unmetered tariff class

Table 3.13 summarises the single charging parameter for the three tariffs in the Unmetered tariff class.

Table 3.13. Unmetered tariff class – charging parameters

Tariff type	Component	Measure	Charging parameter
EA401 Public lighting EA402 Constant unmetered EA403 EnergyLight	Energy consumption charge	c/kWh	Network use of system charge for energy consumed

4 APPROACH TO SETTING TARIFFS

Our approach to setting tariffs is to ensure:

- Revenue is between standalone and avoidable cost for each tariff class.
- Our tariffs reflect estimated long run marginal cost.
- Our tariffs reflect the efficient costs of providing the services.
- Our tariffs mitigate the impact on customers.

Our Explanatory Notes (Section A.5) and attachments provide more information on our pricing principles.

4.1 Revenue is between standalone and avoidable cost for each tariff class

We are required under Section 6.18.5(a) of the Rules to develop annual indicative prices over the regulatory control period that are free of economic subsidy at the tariff class level. We satisfy this obligation by demonstrating that these prices are expected to produce distribution use of system (DUOS) revenue at the tariff class level in each year that lies on or between:

- an upper bound representing the standalone cost of serving the retail customers who belong to that class; and
- a lower bound representing the avoidable cost of not serving those retail customers.

We have estimated the annual standalone and avoidable costs of electricity distribution service provision at the tariff class level over the regulatory control period on the basis of a detailed disaggregated analysis of our annual cost to serve.

See our Explanatory Notes (Section A.5) for more information on how we have calculated standalone and avoidable costs.

Table 4.1 shows how expected DUOS revenue is between avoidable cost and standalone cost for each tariff class for each year of the regulatory period.

Table 4.1. Comparison of Ausgrid's expected DUOS outcome vs standalone and avoidable cost by tariff class – indicative pricing schedule ($m)

	2019/20			2020/21			2021/22			2022/23			2023/24		
Tariff Class	Avoidable cost	Expected DUOS revenue	Stand alone cost	Avoidable cost	Expected DUOS revenue	Stand alone cost	Avoidable cost	Expected DUOS revenue	Stand alone cost	Avoidable cost	Expected DUOS revenue	Stand alone cost	Avoidable cost	Expected DUOS revenue	Stand alone cost
Low Voltage	255.52	1379.67	1430.06	281.67	1384.08	1492.28	309.38	1389.81	1544.63	335.42	1393.45	1602.60	342.35	1398.60	1621.77
High Voltage	15.73	53.96	903.11	17.95	55.15	932.56	20.17	56.70	953.43	22.24	57.84	979.61	22.36	59.31	989.08
Subtransmission	26.59	40.44	339.67	31.33	44.12	353.93	37.21	46.15	366.49	43.20	50.08	380.97	44.20	52.14	385.54
Unmetered	1.54	9.39	1176.07	1.75	8.73	1212.36	1.96	8.10	1237.21	2.16	8.12	1269.34	2.18	8.21	1281.59

Note: Excludes GST.

4.2 Our tariffs reflect estimated long run marginal cost

Our approach to calculating long run marginal cost is the same as the Tariff Structure Statement in our Initial Proposal.

Our Explanatory Notes (Section A.5) and attachments provide more information.

4.3 Our tariffs reflect the efficient costs of providing services

Our approach to setting tariffs is to set prices that are cost reflective. Prices for consumption and demand charges are lower when there is more excess capacity and the cost of additional demand is low. In contrast, prices are higher when increased demand may require additional investment, and the cost of greater demand is high.

Our time windows and seasons are based on our analysis of both residential and business customers across our network, and a commitment to postage-stamp or location-neutral pricing. We aim to signal to our customers those times of the day and year when the cost of greater demand is high.

4.4 Our tariffs mitigate impacts on customers

The proposed assignment policy and tariffs include a demand (introductory) tariff for 12 months to mitigate the impacts on existing residential and small business customers on a flat tariff being reassigned to a new demand tariff through upgrade to a Type 4 (smart) meter triggered by meter failure. The demand (introductory) tariffs give customers an opportunity to understand their patterns of usage for 12 months before being reassigned to the default demand tariff.

Customers assigned to the demand (introductory) tariff have the option to be reassigned to another demand tariff, or to a TOU tariff.

Customers can ask their retailer to reassign them to another eligible tariff, and the retailer then passes this request to Ausgrid. We will be working with both customers and retailers to ensure the new tariffs are explained, including options for alternative demand tariffs.

Section A.6 of our Explanatory Notes has more information on our analysis of the expected bill impacts of our new demand tariffs and our new prices, and Section A.7 discusses complementary measures.

5 INDICATIVE PRICING SCHEDULE

This section presents our indicative network use of system tariffs for each year of the 2019-24 regulatory period.

5.1 Our indicative pricing schedules

Tables 5.1 to 5.5 present our indicative pricing schedules for each year of the regulatory period.

Attachments 10.10,10.11 and 10.13 present the Distribution Use of System, Transmission Use of System and Climate Change Fund components of the pricing schedules for each year.

5.2 Explaining variations to indicative prices

We are required to explain any material variations between the indicative prices in the Tariff Structure Statement and the prices in our annual pricing proposal. While we do not expect there to be material variations, our indicative pricing schedule will vary depending on the latest available data for our price modelling including revenue and consumption. Our energy volume forecast in Attachment 10.15 is based on information available as at the end of October 2018, which does not include complete consumption data for 2017/18 due to the timing of quarterly billing.

For our next annual pricing proposal in April 2019 we will update the econometric model for our energy volume forecast with the latest version of Gross State Product and Household Disposable Income released by the Australian Bureau of Statistics on 16 November 2018. We will also have complete annual consumption data for 2017/18, including the contribution of all tariffs to maximum demand, to inform our annual pricing proposal in April 2019.

Table 5.1. Ausgrid's network tariffs by charging parameter (exclusive of GST) – Indicative – 2019/20

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	37.1024	8.2177							
	EA011	Residential transitional TOU *closed*	37.1024		8.2177	8.2177	8.2177				
	EA025	Residential TOU	46.0410		23.5007	5.4892	3.5087				
	EA111	Residential demand (introductory)	37.1024		7.8913	7.8913	7.8913	1.0178	1.0178		
	EA115	Residential TOU demand	46.0410		23.5007	3.7765	2.7360	4.0714	4.0714		
	EA116	Residential demand	37.1024		2.7416	2.7416	2.7416	20.3568	10.1784		
	EA030	Controlled load 1	0.1508	1.7522							
	EA040	Controlled load 2	11.0480	4.6267							
	EA050	Small business non-TOU *closed*	123.6110	7.9083							
	EA051	Small business transitional TOU *closed*	123.6110		7.9083	7.9083	7.9083				
	EA225	Small business TOU	121.8728		21.5111	7.2663	2.8782				
	EA251	Small business demand (introductory)	121.8728		7.5969	7.5969	7.5969	1.0178	1.0178		
	EA255	Small business TOU demand	121.8728		18.7185	6.6762	2.2108	4.0714	4.0714		
	EA256	Small business demand	121.8728		3.0127	3.0127	3.0127	20.3568	15.2676		
	EA302	LV 40-160 MWh	511.4501		6.4946	2.3498	1.1057			32.8110	
	EA305	LV 160-750 MWh	1652.3676		6.1950	2.2747	1.1181				32.8110
	EA310	LV >750 MWh	2494.9242		4.6546	1.7939	0.8582				32.8110
	EA316	Transitional 40-160 MWh *closed*	133.7667		23.7746	8.6051	1.9307			0.0000	
	EA317	Transitional 160-750 MWh *closed*	133.7667		23.7746	8.6051	1.9307				0.0000
	EA325	LV Connection (standby) *closed*	2382.0766		9.2447	7.5766	2.2322				0.3649
High Voltage	EA360	HV Connection (standby) *closed*	2074.7785		7.4910	3.4192	2.0485				0.6431
	EA370	HV Connection (system)	4931.4407		2.7404	1.7748	1.1480				19.9321
	EA380	HV Connection (substation)	4931.4407		2.4413	1.5433	1.0191				17.1014
Sub-transmission	EA390	ST Connection (system)	6177.2783		2.1078	1.7050	1.1366				6.3573
	EA391	ST Connection (substation)	6177.2783		1.9560	1.4783	1.0302				5.6042
Unmetered	EA401	Public lighting		7.1881							
	EA402	Constant unmetered		8.6290							
	EA403	EnergyLight		6.5974							
Transmission	EA501	Transmission-connected	28125.0000								0.9033

Table 5.2. Ausgrid's network tariffs by charging parameter (exclusive of GST) – Indicative – 2020/21

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	38.0021	8.3538							
	EA011	Residential Transitional TOU	38.0021		8.3538	8.3538	8.3538				
	EA025	Residential TOU *closed*	47.1575		24.0545	5.5512	3.5783				
	EA111	Residential demand (introductory)	38.0021		8.0487	8.0487	8.0487	1.0425	1.0425		
	EA115	Residential TOU demand	47.1575		24.0545	3.7830	2.7571	4.1701	4.1701		
	EA116	Residential demand	38.0021		2.4681	2.4681	2.4681	20.8505	10.4252		
	EA030	Controlled load 1	0.1545	1.8407							
	EA040	Controlled load 2	11.3159	4.7652							
	EA050	Small business non-TOU *closed*	124.8471	7.5991							
	EA051	Business Transitional TOU	124.8471		7.5991	7.5991	7.5991				
	EA225	Small business TOU *closed*	123.0915		22.0106	6.4978	2.6639				
	EA251	Small business demand (introductory)	123.0915		7.2790	7.2790	7.2790	1.0425	1.0425		
	EA255	Small business TOU demand	123.0915		19.1973	5.7818	2.0342	4.1701	4.1701		
	EA256	Small business demand	123.0915		2.3302	2.3302	2.3302	20.8505	15.6378		
	EA302	LV 40-160 MWh	409.1600		6.3061	2.2789	1.0985			33.6066	
	EA305	LV 160-750 MWh	1404.5124		6.0632	2.2842	1.1270				33.6066
	EA310	LV >750 MWh	2555.4230		4.8818	1.9075	0.9651				33.6066
	EA316	Transitional 40-160 MWh closed	194.6278		19.4443	7.2573	1.8289			7.4270	
	EA317	Transitional 160-750 MWh closed	474.8182		19.0353	6.9887	1.7991				9.0196
	EA325	LV Connection (standby) closed	2439.8389		9.4689	7.7604	2.2863				0.3738
	EA327	LV EN residential 160-750 MWh	1404.5124		6.0632	2.2842	1.1270				67.2132
	EA337	LV EN non-residential 160-750 MWh	1404.5124		6.0632	2.2842	1.1270				43.6886
	EA347	LV EN residential >750 MWh	2555.4230		4.8818	1.9075	0.9651				67.2132
	EA357	LV EN non-residential >750 MWh	2555.4230		4.8818	1.9075	0.9651				43.6886
High Voltage	EA360	HV Connection (standby) *closed*	2125.0893		7.7671	3.5960	2.1423				0.6587
	EA370	HV Connection (system)	5051.0219		2.7662	1.7667	1.1449				20.4154
	EA380	HV Connection (substation)	5051.0219		2.5961	1.6261	1.0777				17.5161
	EA367	HV EN residential	5051.0219		2.7662	1.7667	1.1449				39.9185
	EA377	HV EN non-residential	5051.0219		2.7662	1.7667	1.1449				26.5400
Sub-	EA390	ST Connection	6327.0696		2.2216	1.7500	1.1745				6.5114

transmission	EA391	ST Connection (substation)	6327.0696		1.9416	1.5221	1.0735				5.7401
	EA387	ST EN residential	6327.0696		2.2216	1.7500	1.1745				13.0229
	EA397	ST EN non-residential	6327.0696		2.2216	1.7500	1.1745				8.4649
Unmetered	EA401	Public lighting		7.2120							
	EA402	Constant unmetered		8.6794							
	EA403	EnergyLight		6.7013							
Transmission	EA501	Transmission-connected	35156.2500								1.1291

Table 5.3. Ausgrid's network tariffs by charging parameter (exclusive of GST) – Indicative – 2021/22

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	38.9236	8.5079							
	EA011	Residential Transitional TOU	38.9236		8.5079	8.5079	8.5079				
	EA025	Residential TOU *closed*	48.3010		24.6272	5.5932	3.6579				
	EA111	Residential demand (introductory)	38.9236		8.1742	8.1742	8.1742	1.0678	1.0678		
	EA115	Residential TOU demand	48.3010		24.6272	3.7700	2.7755	4.2712	4.2712		
	EA116	Residential demand	38.9236		2.3910	2.3910	2.3910	21.3560	10.6780		
	EA030	Controlled load 1	0.1582	1.8393							
	EA040	Controlled load 2	11.5903	4.7638							
	EA050	Small business non-TOU *closed*	126.0956	7.2790							
	EA051	Business Transitional TOU	126.0956		7.2790	7.2790	7.2790				
	EA225	Small business TOU *closed*	124.3224		22.5061	5.8484	2.4572				
	EA251	Small business demand (introductory)	124.3224		6.9840	6.9840	6.9840	1.0678	1.0678		
	EA255	Small business TOU demand	124.3224		19.6317	5.0354	1.8487	4.2712	4.2712		
	EA256	Small business demand	124.3224		1.8969	1.8969	1.8969	21.3560	16.0170		
	EA302	LV 40-160 MWh	327.3280		5.9378	2.1948	1.1133			34.4215	
	EA305	LV 160-750 MWh	1193.8356		5.6938	2.1978	1.1476				34.4215
	EA310	LV >750 MWh	2617.3888		4.9746	1.9973	1.0834				34.4215
	EA316	Transitional 40-160 MWh closed	247.5390		14.7563	5.2856	1.5516			18.1904	
	EA317	Transitional 160-750 MWh closed	848.1128		13.7081	4.6006	1.4725				22.2076
	EA325	LV Connection (standby) closed	2499.0020		9.6985	7.9485	2.3418				0.3828
	EA327	LV EN residential 160-750 MWh	1193.8356		5.6938	2.1978	1.1476				68.8430
	EA337	LV EN non-residential 160-750 MWh	1193.8356		5.6938	2.1978	1.1476				44.7480
	EA347	LV EN residential >750 MWh	2617.3888		4.9746	1.9973	1.0834				68.8430
	EA357	LV EN non-residential >750 MWh	2617.3888		4.9746	1.9973	1.0834				44.7480
High Voltage	EA360	HV Connection (standby) *closed*	2176.6200		8.0660	3.7932	2.2459				0.6747
	EA370	HV Connection (system)	5173.5029		2.8352	1.7845	1.1576				20.9105
	EA380	HV Connection (substation)	5173.5029		2.7148	1.6791	1.1181				17.9408
	EA367	HV EN residential	5173.5029		2.8352	1.7845	1.1576				40.8865
	EA377	HV EN non-residential	5173.5029		2.8352	1.7845	1.1576				27.1836
Sub-	EA390	ST Connection	6480.4931		2.3359	1.7997	1.2143				6.6693

transmission	EA391	ST Connection (substation)	6480.4931		2.0398	1.5623	1.1132				5.8793
	EA387	ST EN residential	6480.4931		2.3359	1.7997	1.2143				13.3387
	EA397	ST EN non-residential	6480.4931		2.3359	1.7997	1.2143				8.6701
Unmetered	EA401	Public lighting		7.3676							
	EA402	Constant unmetered		8.4484							
	EA403	EnergyLight		6.8010							
Transmission	EA501	Transmission-connected	43945.3125								1.4114

Table 5.4. Ausgrid's network tariffs by charging parameter (exclusive of GST) – Indicative – 2022/23

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	39.8674	8.6888							
	EA011	Residential Transitional TOU	39.8674		8.6888	8.6888	8.6888				
	EA025	Residential TOU *closed*	49.4722		25.2028	5.6403	3.7403				
	EA111	Residential demand (introductory)	39.8674		8.3434	8.3434	8.3434	1.0937	1.0937		
	EA115	Residential TOU demand	49.4722		25.2028	3.8303	2.8375	4.3748	4.3748		
	EA116	Residential demand	39.8674		2.3621	2.3621	2.3621	21.8739	10.9370		
	EA030	Controlled load 1	0.1620	1.8268							
	EA040	Controlled load 2	11.8714	4.7513							
	EA050	Small business non-TOU *closed*	127.3566	7.0284							
	EA051	Business Transitional TOU	127.3566		7.0284	7.0284	7.0284				
	EA225	Small business TOU *closed*	125.5657		23.0235	5.2482	2.2697				
	EA251	Small business demand (introductory)	125.5657		6.7303	6.7303	6.7303	1.0937	1.0937		
	EA255	Small business TOU demand	125.5657		20.0853	4.3821	1.6938	4.3748	4.3748		
	EA256	Small business demand	125.5657		1.4818	1.4818	1.4818	21.8739	16.4054		
	EA302	LV 40-160 MWh	278.2288		5.3196	2.0174	1.0981			35.2562	
	EA305	LV 160-750 MWh	1074.4520		5.1167	2.0385	1.1405				35.2562
	EA310	LV >750 MWh	2680.8572		4.8274	2.0051	1.1728				35.2562
	EA316	Transitional 40-160 MWh closed	268.8021		8.8640	3.0544	1.2355			30.0142	
	EA317	Transitional 160-750 MWh closed	1074.4520		7.2418	2.1511	1.1415				35.2562
	EA325	LV Connection (standby) closed	2559.5996		9.9337	8.1413	2.3985				0.3921
	EA327	LV EN residential 160-750 MWh	1074.4520		5.1167	2.0385	1.1405				70.5124
	EA337	LV EN non-residential 160-750 MWh	1074.4520		5.1167	2.0385	1.1405				45.8330
	EA347	LV EN residential >750 MWh	2680.8572		4.8274	2.0051	1.1728				70.5124
	EA357	LV EN non-residential >750 MWh	2680.8572		4.8274	2.0051	1.1728				45.8330
High Voltage	EA360	HV Connection (standby) *closed*	2229.4003		8.3660	3.9891	2.3492				0.6911
	EA370	HV Connection (system)	5298.9538		2.8418	1.7591	1.1433				21.4175
	EA380	HV Connection (substation)	5298.9538		2.7824	1.6952	1.1341				18.3759
	EA367	HV EN residential	5298.9538		2.7824	1.6952	1.1341				41.8779
	EA377	HV EN non-residential	5298.9538		2.8418	1.7591	1.1433				27.8427
Sub-	EA390	ST Connection	6637.6369		2.3945	1.8081	1.2219				6.8310

transmission	EA391	ST Connection (substation)	6637.6369		2.1064	1.5789	1.1296				6.0219
	EA387	ST EN residential	6637.6369		2.3945	1.8081	1.2219				13.6621
	EA397	ST EN non-residential	6637.6369		2.3945	1.8081	1.2219				8.8804
Unmetered	EA401	Public lighting		7.3361							
	EA402	Constant unmetered		8.3658							
	EA403	EnergyLight		7.1434							
Transmission	EA501	Transmission-connected	54931.6406								1.7643

Table 5.5. Ausgrid's network tariffs by charging parameter (exclusive of GST) – Indicative – 2023/24

Tariff Class	Tariff Code	Tariff Name	Network Access Charge	Energy consumption charge				Demand charge		Capacity charge	
				Non-TOU	Peak	Shoulder	Off-peak	High season	Low season	Peak	Peak
			c/day	c/kWh	c/kWh	c/kWh	c/kWh	c/kW/day	c/kW/day	c/kW/day	c/kVA/day
Low Voltage	EA010	Residential non-TOU *closed*	40.8342	8.9067							
	EA011	Residential Transitional TOU	40.8342		8.9067	8.9067	8.9067				
	EA025	Residential TOU *closed*	50.6719		25.7991	5.7708	3.8771				
	EA111	Residential demand (introductory)	40.8342		8.5424	8.5424	8.5424	1.1202	1.1202		
	EA115	Residential TOU demand	50.6719		25.7991	3.9050	2.9206	4.4809	4.4809		
	EA116	Residential demand	40.8342		2.3608	2.3608	2.3608	22.4043	11.2022		
	EA030	Controlled load 1	0.1660	1.8209							
	EA040	Controlled load 2	12.1592	4.7454							
	EA050	Small business non-TOU *closed*	128.6301	6.7823							
	EA051	Business Transitional TOU	128.6301		6.7823	6.7823	6.7823				
	EA225	Small business TOU *closed*	126.8213		23.5624	4.6501	2.0984				
	EA251	Small business demand (introductory)	126.8213		6.4804	6.4804	6.4804	1.1202	1.1202		
	EA255	Small business TOU demand	126.8213		20.5574	3.7794	1.5684	4.4809	4.4809		
	EA256	Small business demand	126.8213		1.1833	1.1833	1.1833	22.4043	16.8032		
	EA302	LV 40-160 MWh	250.4059		4.4796	1.7868	1.0889			36.1111	
	EA305	LV 160-750 MWh	1020.7294		4.4346	1.9715	1.2326				36.1111
	EA310	LV >750 MWh	2745.8646		4.3670	1.9180	1.2348				36.1111
	EA316	Transitional 40-160 MWh closed	250.4059		4.4796	1.7868	1.0889			36.1111	
	EA317	Transitional 160-750 MWh closed	1020.7294		4.4346	1.9715	1.2326				36.1111
	EA325	LV Connection (standby) closed	2621.6667		10.1746	8.3387	2.4567				0.4016
	EA327	LV EN residential 160-750 MWh	1020.7294		4.4346	1.9715	1.2326				72.2222
	EA337	LV EN non-residential 160-750 MWh	1020.7294		4.4346	1.9715	1.2326				46.9444
	EA347	LV EN residential >750 MWh	2745.8646		4.3670	1.9180	1.2348				72.2222
	EA357	LV EN non-residential >750 MWh	2745.8646		4.3670	1.9180	1.2348				46.9444
High Voltage	EA360	HV Connection (standby) *closed*	2283.4605		8.7137	4.2299	2.4739				0.7078
	EA370	HV Connection (system)	5427.4468		2.8973	1.7617	1.1487				21.9369
	EA380	HV Connection (substation)	5427.4468		2.8736	1.7151	1.1477				18.8215
	EA367	HV EN residential	5427.4468		2.8973	1.7617	1.1487				42.8934
	EA377	HV EN non-residential	5427.4468		2.8973	1.7617	1.1487				28.5179
Sub-	EA390	ST Connection	6798.5913		2.4919	1.8455	1.2528				6.9967

transmission	EA391	ST Connection (substation)	6798.5913		2.1922	1.6090	1.1592					6.1679
	EA387	ST EN residential	6798.5913		2.4919	1.8455	1.2528					13.9934
	EA397	ST EN non-residential	6798.5913		2.4919	1.8455	1.2528					9.0957
Unmetered	EA401	Public lighting		7.3679								
	EA402	Constant unmetered		8.4328								
	EA403	EnergyLight		7.3190								
Transmission	EA501	Transmission-connected	68664.5508									2.2053

6 COMPLIANCE CHECKLIST

Tables 6.1 to 6.8 show how the tariffs in our Tariff Structure Statement comply with the requirements of Chapter 6 of the Rules.

Table 6.1. Regulatory proposal and proposed tariff structure statement – 6.8.2 – Submission of tariff structure statement

Rule provision	Amending clause	Requirement	Section in main TSS	Other documents
6.8.2(a)	11.73.2(a)	A Distribution Network Service Provider must, whenever required to do so under paragraph (b), submit to the AER a regulatory proposal and a proposed tariff structure statement related to the distribution services provided by means of, or in connection with, the Distribution Network Service Provider's distribution system.	Entire TSS	
6.8.2(b)	11.73.2(a)	A regulatory proposal and a proposed tariff structure statement must be submitted: by 8 January 2019.	Entire TSS	
6.8.2(c)	11.73.2(a)	A proposed tariff structure statement must be accompanied by information that contains a description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles for direct control services.	Entire TSS	Explanatory Notes
6.8.2(c1a)	11.73.2(a)	The proposed tariff structure statement must be accompanied by an overview paper which includes a description of how the Distribution Network Service Provider has engaged with retail customers and retailers in developing the proposed tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement		Regulatory Proposal
6.8.2(d1)		The tariff structure statement must be accompanied by an indicative pricing schedule.	Section 5	
6.8.2(d2)		The tariff structure statement must comply with the pricing principles for direct control services.	Entire TSS	Explanatory Notes
6.8.2(e)		If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate tariff structure statement is to be submitted for each distribution system.	Not applicable	
6.8.2(f)		If, at the commencement of this Chapter, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate tariff structure statement is to be submitted for each part as if it were a separate distribution system.	Not applicable	

Table 6.2. Distribution Pricing Rules – 6.18.1A –Tariff Structure Statement

Rule provision	Amending clause	Requirement	Section in main TSS	Other documents
6.18.1A(a)(1)		The tariff structure statement must include the tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period.	Section 2	
6.18.1 A(a)(2)		The tariff structure statement must include 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).	Section 3	
6.18.1A(a)(3)		The tariff structure statement must include the structures for each proposed tariff.	Section 3	
6.18.1A(a)(4)		The tariff structure statement must include the charging parameters for each proposed tariff.	Section 3	
6.18.1A(a)(5)		The tariff structure statement must include a description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal during the relevant regulatory control period in accordance with clause 6.18.5 (pricing principles).	Section 4	Explanatory Notes
6.18.1A(b)		The tariff structure statement must comply with the pricing principles for direct control services.	Entire document	
6.18.1A(e)		A tariff structure statement must be accompanied by an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.	Section 5	

Table 6.3. Distribution Pricing Rules – 6.18.3 –Tariff Classes

Rule provision	Amending clause	Requirement	Section in main TSS	Other documents
6.18.3(b)		Each customer for direct control services must be a member of 1 or more tariff classes.	Section 2	
6.18.3(c)		Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers to whom alternative control services are supplied (but a customer for both standard control services and alternative control services may be a member of 2 or more tariff classes).	Section 2	
6.18.3(d)		A tariff class must be constituted with regard to: (1) the need to group retail customers together on an economically efficient basis; and (2) the need to avoid unnecessary transaction costs.	Section 2	

Table 6.4. Distribution Pricing Rules – 6.18.4 – Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging

Rule provision	Requirement	Section in main TSS	Other documents
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles:		
6.18.4(a)(1)	Retail customers should be assigned to tariff classes on the basis of one or more of the following factors: (i) the nature and extent of their usage; (ii) the nature of their connection to the network; (iii) whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;	Section 2	
6.18.4(a)(2)	Retail customers with a similar connection and usage profile should be treated on an equal basis;	Sections 2 and 3	
6.18.4(a)(3)	However, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile;	Sections 2 and 3	
6.18.4(a)(4)	A Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review. Note: If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.	Sections 2 and 3	
6.18.4(b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Section 3	

Table 6.5. Distribution Pricing Rules – 6.18.5 – Application of the Pricing Principles

Rule provision	Requirement	Section in main TSS	Other documents
6.18.5(a)	The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.	Entire TSS	
6.18.5(b)	Subject to paragraph (c), a DNSP's tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	Section 4	
6.18.5(c)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: (1) to the extent permitted under paragraph (h); and (2) to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	Section 4	
6.18.5(d)	A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective.	Entire TSS	

Table 6.6. Distribution Pricing Rules – 6.18.5 – Application of the Pricing Principles

Rule provision	Requirement	Section in main TSS	Other documents
6.18.5(e)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those retail customers.	Section 4	Explanatory Notes
6.18.5(f)	Each tariff must be based on the long-run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied, to be determined having regard to: (1) the costs and benefits associated with calculating, implementing and applying that method as proposed; (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and (3) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.	Section 4	Attachment 10.03 (LRMC model)
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	Section 4	Explanatory Notes

Table 6.7. Distribution Pricing Rules – 6.18.5 – Application of the Pricing Principles (continued)

Rule provision	Requirement	Section in main TSS	Other documents
6.18.5(h)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) the extent to which retail customers can choose the tariff to which they are assigned; and (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 4	
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: (1) the type and nature of those retail customers; and (2) the information provided to, and the consultation undertaken with, those retail customers.	Section 3	
6.18.5(j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Entire TSS	

Table 6.8. Distribution Pricing Rules – 6.18.1B – Amending a tariff structure statement with the AER's approval

Rule provision	Requirement	Section in amended TSS	Other documents
6.18.1B(a)	A Distribution Network Service Provider may request the AER to approve an amendment to its current tariff structure statement no later than nine months before the start of a regulatory year (other than the first regulatory year of a regulatory control period).	Entire Amendment to TSS	
6.18.1B(b)	A request for an amendment to a tariff structure statement under paragraph (a) must include: (1) the proposed amended tariff structure statement; (2) a description of the event that has occurred to cause the Distribution Network Service Provider to seek an amendment to its current tariff structure statement and why the event: (i) was beyond the reasonable control of the Distribution Network Service Provider; and (ii) could not reasonable have been foreseen by the Distribution Network Service Provider at the time its current tariff structure statement was approved by the AER. (3) a description and justification of the differences between the proposed amended tariff structure statement and the Distribution Network Service Provider's current tariff structure statement; (4) a description of how the differences referred to in sub-paragraph (3) would impact the other elements of the tariff structure statement; (5) a description of how the proposed amended tariff structure statement would better comply with the pricing principles for direct control services than the current tariff structure statement; and (6) a description of how the Distribution Network Service Provider has engaged with retail customers and retailers in developing the proposed amended tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement.		Explanatory Notes to the Amendment
6.18.1B(c)	As a result of the event referred to in sub-paragraph (1), the proposed amended tariff structure statement would, or would be likely to, materially better comply with the pricing principles for direct control services than the Distribution Network Service Provider's current tariff structure statement.		Explanatory Notes to the Amendment

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APPENDIX A – EXPLANATORY NOTES

These Explanatory Notes provide additional information to support our Tariff Structure Statement.

APPENDIX A – EXPLANATORY NOTES

A.1 Overview

Why a revised Tariff Structure Statement?

Our initial Tariff Structure Statement was submitted in April 2018. It proposed our initial approach to tariff structures, charging parameters and indicative pricing to comply with the National Electricity Rules and provide safe and reliable electricity to our customers. Recognising that a quarter of our 1.7 million customers are already on a cost reflective Time of Use tariff, we initially proposed an increase in the fixed daily charge to access our network, and lower variable charges. We proposed a demand tariff with a demand charge that would not come into effect until we conducted further research on its structure and impacts.

Following feedback from consumer representatives, stakeholder submissions to our Initial Proposal and in response to the AER's Draft Decision, we have undertaken a significant engagement process with the customer representative groups that form our Pricing Working Group to co-design a substantially revised approach. Our revised Tariff Structure Statement reflects that approach and introduces demand tariffs for residential and small business customers. Our tariffs and assignment policies are revised so that the default assignment is to the most cost reflective tariff, a new seasonal demand tariff with a flat energy charge, with an opt out available to another cost reflective tariff which has a seasonal Time of Use (TOU) structure and a small non-seasonal demand component. Our TOU tariffs also remain available as a cost-reflective option.

Four key reasons we are changing our approach to pricing:

1. In their Retail Electricity Pricing Inquiry of July 2018, the **Australian Competition and Consumer Commission (ACCC)** recommended the industry fast track the introduction of cost reflective network tariffs, with mandatory assignment of demand tariffs for all customers with metering capable of supporting them.
2. Throughout this regulatory determination process **customer representatives** have advocated strongly for the accelerated introduction of demand tariffs.
3. In their draft determination **the AER** supported the ACCC and customer advocate views, recommending that we introduce demand tariffs with an opt out to another cost reflective tariff.
4. **We** believe this change is in the best long-term interest of our customers, and will make a significant contribution to unlocking new energy delivery models and lowering whole of system costs for all electricity consumers.

Our new approach aligns with the AER's position expressed in its Issues Paper and in its Draft Decision of 1 November 2018.[1] The AER recognises that Ausgrid is one of the more advanced distributors in the National Electricity Market in the penetration of cost reflective pricing and the cost reflectivity of existing tariffs. The new demand tariffs put Ausgrid at the forefront of the national tariff reform process being undertaken in the long-term interest of all users of our shared energy system. Demand tariffs are a powerful tool that can deliver long-term savings to the energy bills of all customers.

The majority of residential and small business customers will be immediately better off under our new demand tariffs, however, in the short term the network bills for some customers may increase. Whether customers experience bill reductions or increases under the new demand tariffs will depend on how retailers pass through the price signal, the nature of each customer's load profile, and the extent to which customers respond to price signals and shift or flatten their load including the impact of any complementary measures offered to customers to help them in this process (see Section A.7 for measures).

[1] Australian Energy Regulator (2018) *Draft Decision Ausgrid Distribution Determination*, November 2018, www.aer.gov.au

To ensure this reform achieves its objective it will benefit from cooperation from retailers and support from government in helping customers who might be adversely affected by the reform access targeted assistance. We will also develop information and education materials for customers who might be affected by the new tariffs to explain the drivers of the network bill for particular groups of customers and suggest measures to help customers save under our new network tariffs.

Our revised Tariff Structure Statement aligns with the position of the Australian Competition and Consumer Commission (ACCC). The ACCC strongly supported cost reflective pricing in Recommendation 14 of its Retail Electricity Pricing Inquiry of July 2018[2]:

> 14. The ACCC considers that steps should be taken to accelerate the take up of cost-reflective network pricing. Governments should agree to mandatory assignment of cost-reflective network pricing on retailers, ending existing opt-in and opt-out arrangements. Mandatory assignment of the network tariff should apply for all customers of a retailer that have metering capable of supporting cost-reflective tariffs (that is, a smart or interval meter). Retailers should not be obligated to reflect the cost-reflective network tariff structure in their customers' retail tariffs, but should be free to innovate in the packaging of the network tariff as part of their retail offer. Given the potential for negative bill shock outcomes from any transition to cost-reflective network tariffs should retailers pass these network tariffs through to customers, governments should legislate to ensure transitional assistance is provided for residential and small business customers. This assistance should focus on maximising the benefits, and reducing the transitional risks, of the move to cost-reflective pricing structures. This includes:
>
> - a compulsory 'data sampling period' for consumers following installation of a smart meter
> - a requirement for retailers to provide a retail offer using a flat rate structure
> - additional targeted assistance for vulnerable consumers.
>
> Demand tariffs, which charge retailers based on their customers' maximum demand during pre-determined typical system peak times, represent an appropriate structure for the initial mandatorily assigned network tariffs. This tariff structure provides a balance of the objectives of cost reflectivity, simplicity and price certainty.

In addition, as noted by the AER, customer representative groups have pushed for the accelerated adoption of cost reflective pricing[3]. After multiple working sessions with our Pricing Working Group a co-designed pricing strategy emerged that met the specifications outlined in their Pricing Directions document (Attachment 10.14):

> A key group of stakeholders, including the Consumer Challenge Panel (CCP), Energy Consumers Australia (ECA), Public Interest Advocacy Centre (PIAC) and Total Environment Centre (TEC) have advocated for cost reflective tariffs in their paper, Pricing Directions. Pricing Directions calls for prioritising a transition to demand or capacity tariffs, and argues that where there is an opt-out default cost tariff system, the opt-out option should not be to a flat energy charge (and no demand charge).

What is our revised approach?

In our revised Tariff Structure Statement, our guiding principles and objectives for pricing are unchanged (Table A1.1). Our overarching principle for pricing reform is to reduce customers' bills by lowering whole of system costs and make sure that our network costs are shared fairly between our customers. Our analysis shows that our revised approach meets the National Electricity Rules and balances objectives.

Many elements of our tariff structures are unchanged from their current 2018/19 structure. Our existing cost reflective seasonal TOU tariff will continue for customers with a Type 5 (interval) meter. It will also be available as an opt-out option from our new demand tariffs. Our existing non-cost reflective tariff will also continue for customers with a Type 6 (accumulation) meter, but is closed to new connections.

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[2] Australian Competition and Consumer Commission (2018) *Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry – Final Report*, July 2018, www.accc.gov.au

[3] Australian Energy Regulator (2018) *Issues Paper: NSW Electricity Distribution Determinations: Ausgrid, Endeavour Energy, Essential Energy 2019 to 2024*, June 2018, www.aer.gov.au

Our transitional residential and small business tariffs will be pegged to the corresponding flat tariffs. These tariffs are closed to new customers.

Our transitional LV tariffs for 40-160 MWh and 160-750 MWh will transition over the determination period towards the corresponding capacity based tariffs.

Our existing tariffs for High Voltage, Subtransmission and Transmission customers will continue.

Table A1.1. How pricing promotes affordable, sustainable and reliable network services

Objective	How can pricing promote these outcomes?
Affordable	• Rewards customers who actively manage their contribution to peak demand and place a low cost burden on the shared system. • Encourages customers to use our network when the cost of doing so is low, leading to lower rates overall. • Promotes fairer outcomes between customers with different characteristics (such as those with and without distributed energy resources or peaky load). • Ensures all customers make a fair contribution to the cost of the network service they use. • Gives customers more choice and control over how they are billed for access to the grid while still promoting the development of more innovative retail products to further increase the choices available.
Reliable	• Reduces incidences of spikes in demand that can lead to network outages. • Encourages a more responsive demand-side to deliver the reliability outcomes that our customers expect at a lower cost.
Sustainable	• Unlocks new potential energy sources for customers who cannot currently benefit from distributed energy resources, by levelling the playing field for shared energy schemes such as community solar and storage. • Encourages customers to use distributed energy resources in a way that helps them to better manage their consumption at peak and non-peak periods, and lowers grid costs for all. • Encourages the adoption of electric vehicles without unnecessarily increasing grid costs. • Promotes the lowest cost transition to a lower carbon economy.

Demand tariffs a key element of our revised approach

Our revised Tariff Structure Statement proposes to introduce a set of three demand tariffs from 1 July 2019 for residential and small business customers including:

- a demand tariff
- a demand (introductory) tariff
- a TOU demand tariff.

Demand tariffs (tariffs that include a demand charge) will help us reduce peak demand. Reducing peak demand, which is the principal driver of our future costs, will reduce costs for all customers in the long term. Our demand tariffs provide a more equitable way to recover our total network costs and send price signals to adjust network use.

Our **demand** tariff:

- has a network access charge, a flat energy consumption charge, and a two rate (seasonal) demand charge
- is the default tariff for new connections and meter change (to a smart meter) initiated by a customer.

Our **demand (introductory)** tariff:

- has a network access charge, a flat energy consumption charge, and a seasonal demand charge set to the same low level in both seasons (effectively a flat demand charge)
- mirrors the behaviour of our legacy flat energy tariffs, while introducing time of use consumption windows, and (very small) seasonal demand charges – to allow customers to understand their consumption and demand patterns without experiencing any material changes to their bill
- is available for 12 months only for existing customers on flat tariffs when they replace their meter due to meter failure including network-driven meter family replacement
- serves as a sampling tariff to help customers learn and adjust their behaviour before facing a cost reflective demand tariff.

Our **TOU demand** tariff:

- has a network access charge, a seasonal time of use energy consumption charge and a seasonal demand charge set to the same low level in both seasons (effectively a flat demand charge)
- is for any customer with a smart meter as an opt out alternative tariff to the default tariff
- mirrors the behaviour of our existing TOU tariffs, while introducing a moderate demand charge component, as an important foundational building block for future tariff reform.

Charging parameters of demand tariffs

Each demand tariff has three components with six charging parameters, although some of the parameters may have the same price:

- a fixed daily charge (in cents per day)
- an energy consumption charge, charged in three periods: peak, shoulder and off-peak (in cents per kWh of energy consumption)
- a demand charge, charged for maximum 30 minute kW demand a month in the demand window in two seasons: High season months and Low season months (in cents per kW demand per day). The demand charge (in cents per kW per day):
    - is applied to the maximum kW demand over any 30 minute period within the defined demand window on a working weekday in each month, with the resulting charge applied for each day in the month (before being reset for the next month)
    - is based on the definition of a demand window for measuring the maximum demand which is aligned with a corresponding definition of a time of use time period window for peak energy consumption
    - varies by season, being higher in a High season month, and lower in a Low season month, with the definition of seasonality aligned with a corresponding season for a time of use time period
    - the time window for time of use peak energy and maximum demand varies by season for residential customers (2-8 pm in ‘summer’ months, 5-9 pm in ‘winter’ months), but does not vary for small business customers (2-8 pm in all months of the year).

Our demand (introductory) tariff and TOU demand tariff have the same charging parameters as the demand tariff, with the only differences being the prices associated with each component.

Summary of major pricing reforms

Table A1.2 summarises our major pricing reforms for the 2019-24 regulatory period.

Table A1.2. Summary of major pricing reforms over the 2019-24 period

Proposed reform	Description	Benefits for our customers
Introduce demand tariffs	Introduce a set of demand tariffs (tariffs which include a demand charge component) for residential and small business customers: • **a demand tariff** as a default assignment for new connections and customer-initiated meter replacement or upgrade • **a time of use demand** tariff as a second cost reflective option • **a demand (introductory)** tariff as a sampling tariff to ease the transition to a demand tariff where a customer's meter change to a smart meter is due to failure of an accumulation meter	• Ensures customers retain greater control of the network component of their bills while moving to cost reflective tariffs • Gives customers choice about how they are charged for their energy • Encourages customers to invest in cost effective distributed energy resources that help them to better manage their consumption at peak periods • Promotes fairer outcomes between customers with different demand characteristics (those with and without distributed energy resources, or peaky load) • Provides greater certainty for those considering or making investments in new technology • Gives customers new to cost reflective charging mechanisms time to learn about and adjust their usage patterns, but does not confuse customers with a 12 month sampling period where this is unlikely to be beneficial (such as new connections or customers that experience a step change in their demand profile when they install distributed energy resources) • Accelerates the development of more innovative retail tariffs that manage the risk of both wholesale and network costs for customers
Align charging windows for small business customers	Align charging windows for seasonal time of use peak energy, seasonal peak demand charges and annual capacity charge to 2-8 pm on working weekdays	• Provides more cost reflective peak price signals • Enables easier understanding and better management of peak demand • Achieves consistency within the business tariff segment

Who is affected by the revised approach, and how?

Only some of our customers will be affected by the introduction of the set of demand tariffs. The type of impact will depend on customers' usage patterns and willingness and ability to make changes to their usage patterns.

Our allowed revenue for the first year of the 2019-24 regulatory period is lower than the revenue we recovered through tariffs in 2018/19. The lower revenue requirement translates into price reductions for our customers. While distributing these savings to our customers, we are adjusting our current revenue shares embedded in particular tariffs to move them closer to the efficient level. This means some tariffs are receiving a smaller share of savings, if their current contribution to the system peak demand exceeds the share of revenue funded by the tariff, adjusted for the relative growth in customer numbers on this tariff. By moving tariffs closer to their contribution to peak demand we are improving the cost allocation method and the fairness of our tariff structure.

Our customers' bills have several components: generation, network, green schemes and retail. Based on the indicative pricing in our revised Tariff Structure Statement, the average reduction in the network component of the bill in 2019/20 of a typical residential customer using 5,000 kWh a year on our most common tariff, EA010 non-Time of Use tariff, is expected to be 12% (Table A1.3) and for a typical small business customer using 10,000 kWh a year it is 12% (Table A1.4). Table A1.5 shows the network component of the bill in 2019/20 for a typical customer on each of our two medium business tariffs and for a typical large business customer. The final prices for each tariff will continue to be determined on an annual basis.

Table A1.3. Impacts on typical residential customer bills in 2019/20

Tariff	Usage MWh pa	Network component of bill in 2019/20	Percentage and $ change from 2018/19	Bill with 10% reduction in demand
Existing: EA010 Non-Time of Use	5	$565	-12% (-$75)	
Existing: EA025 Time of Use	5	$556	0% (-$2)	
New: EA116 Demand	5	$504		$482
New: EA115 Time of Use demand	5	$554		$549

Note: Excludes GST. Percentage change not available for new tariffs as they did not exist in 2018/19.

Table A1.4. Impacts on typical small business customer bills in 2019/20

Tariff	Usage MWh pa	Network component of bill in 2019/20	Percentage and $ change from 2018/19	Bill with 10% reduction in demand
Existing: EA050 Non-Time of Use	10	$1,298	-12% (-$169)	
Existing: EA225 Time of Use	10	$1,268	-2% (-$27)	
New: EA256 Demand	10	$1,240		$1,212
New: EA255 Time of Use demand	10	$1,251		$1,245

Note: Excludes GST. Percentage change not available for new tariffs as they did not exist in 2018/19.

Table A1.5. Impacts on typical medium and large business customer bills in 2019/20

Tariff	Usage MWh pa	Network component of bill in 2019/20	Percentage and $ change from 2018/19
Existing: EA302 40-160 MWh pa	70	$6,795	-13% (-$1,047)
Existing: EA305 160-750 MWh pa	300	$25,376	-10% (-$2,717)
Existing: EA310 >750 MWh pa	1,000	$61,646	-4% ($2,270)

Note: Excludes GST. Usage is for a 'typical' customer on each tariff.

Many elements of our existing structures will remain the same as in 2018/19 and existing customers will see no change to the structure of their tariff. The demand tariffs with a new demand charge will only apply to customers with a Type 4 (smart) meter. Customers with a Type 6 (accumulation) or Type 5 (interval) meter will not be affected until their meter changes.

Our revised approach will affect new customers from 1 July 2019, and when existing customers change their meter to a Type 4 (smart) meter. The number of customers currently on each tariff type by meter type is summarised in Table A2.1 in Section A.2. The number and proportion of our customers on a demand tariff will increase over time.

Customers on our current tariffs who require assistance with their bills are likely to continue to require assistance if they are assigned to a demand tariff with a demand charge, but may have more control over their bill. We will work with these customers and stakeholders to minimise the impact of a change to a demand tariff on customers in need of assistance. We will work with the Energy and Water Ombudsman of NSW (EWON), and the NSW government to assist eligible customers' access exiting rebate schemes such as the Low Income Household Rebate, Energy Accounts Payment Assistance, Family Energy Rebate, Life Support Rebate and Medical Energy Rebate.

Our revised approach continues our technology neutral position and does not distort customers' decision making or attempt to pick technology winners.

How will the revised approach work and meet the Rules?

We are introducing the set of demand tariffs to accelerate the take up of cost reflective network pricing. However, the extent to which demand tariffs have the intended effect to reduce network peaks depends on strong and effective communication with stakeholders including customers, retailers and third party technology providers.

To the extent that retailers choose to pass the structure of the underlying demand tariff to our customers (or a version that includes some form of the new demand component), customers will need to understand how their demand tariff works, and how they can change their usage to have more control over their bill.

In addition to the information retailers choose to provide their customers, either on their bills or by other channels, customers will be able to download information about their usage and demand directly from our website.

Third party technology providers can play an important role in providing tools to help customers on a demand tariff with a maximum 30 minute peak demand charge understand their demand and manage it.

Retailers may choose to offer customers products that mask the structure of the underlying network tariff. As long as retailers remain exposed to the cost reflective price signal, the incentive to reduce demand, and hence cost on the shared grid, still exists and will ultimately be facilitated by the competitive market, and hence meet the objectives of the reform.

However retailers respond, we will be working closely with customer groups, retailers and government to ensure the introduction of demand tariffs is appropriately communicated to customers.

Our revised Tariff Structure Statement, Explanatory Notes and accompanying attachments together explain how our revised approach including residential and small business demand tariffs meets the National Electricity Rules to ensure prices are cost reflective.

When will the revised approach be implemented?

We will introduce the new set of demand tariffs from 1 July 2019 onwards for new customers (new connections), and to existing customers when they change their meter.

As the AER is expected to make a final determination on our revised Tariff Structure Statement in April 2019, we only have a short window of time before 1 July 2019 to communicate the change to directly affected customers, retailers and other stakeholders.

We expect the number of customers affected will increase over time after 1 July 2019 throughout the five-year regulatory period, allowing communication strategies to be reviewed and expanded over time.

We believe communications about new demand tariffs will be most effective in the context of an ongoing sector-wide energy literacy campaign for all customers, closely supported by all key stakeholders including the AER, the energy sector (distributors and retailers), customer advocates, other stakeholders including the Energy and Water Ombudsman of NSW and government representatives.

As part of communications, we also support the Australian Competition and Consumer Commission's Recommendation 38 to improve energy literacy of vulnerable customers[4]:

> In addition to existing funding, the Australian Government and the relevant state or territory government should fund (to a value of $5 per household in each NEM region, or $43 million NEM-wide, per annum) a grant scheme for consumer and community organisations to provide targeted support to assist

[4] Australian Competition and Consumer Commission (2018) *Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry—Final Report*, July 2018, www.accc.gov.au

vulnerable consumers to improve energy literacy. This grant scheme should be modelled on the approach taken by the Queensland Council of Social Services in administering the Switched on Communities program. This targeted support will assist vulnerable consumers to participate in the retail electricity market and choose an offer that suits their circumstances.

What happens next?

We recognise that introducing demand tariffs will be a big change for some of our customers and requires a comprehensive communication campaign from all stakeholders.

We support the Australian Competition and Consumer Commission's Recommendation 14[5] in its Retail Electricity Pricing Inquiry of July 2018 that governments should appropriately fund communication campaigns around the benefits of cost reflective pricing and smart meters to build community acceptance and awareness of individual and community wide benefits, as well as customer awareness of their rights.

We are continuing to work with customer advocates including the Energy and Water Ombudsman of NSW and our Pricing Working Group to support communication of our tariff changes. We are working with retailers on the implementation of the proposed new tariffs. We are discussing our changes with our fellow distributors in NSW, Endeavour Energy and Essential Energy, to ensure a consistent approach where possible, recognising the differences between networks.

In communicating the changes to our customers, we will emphasise:

- why we are changing and how it will benefit customers by ensuring affordable, reliable and sustainable electricity supply
- how customers can manage their bills and what tools and information are available to assist them
- options and procedures for customers to choose an alternative demand tariff
- complementary measures and assistance available for customers in need.

All communications will include further engagement with retailers (once they have had more time to consider and plan their response to the introduction of the new network tariffs) and where possible will involve joint or retailer led communications that minimise the risk of conflicting messages.

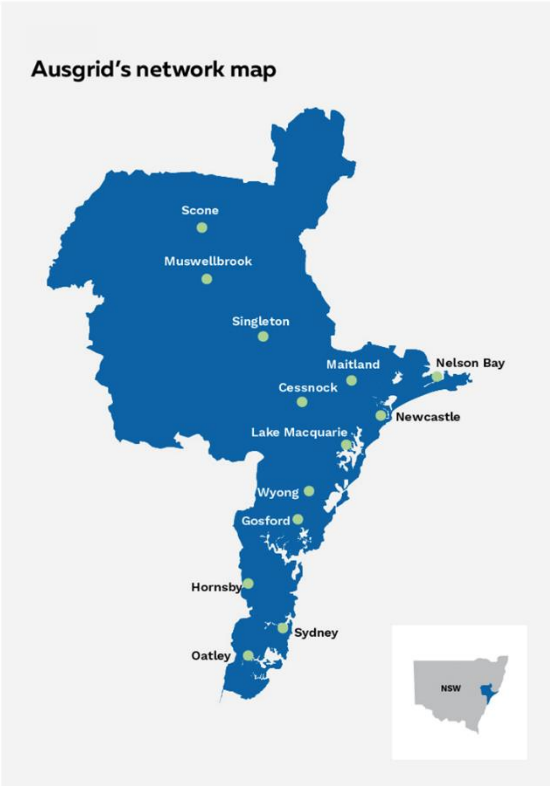
The timing of the AER's final determination in April 2019 and our proposed introduction of the demand tariffs from 1 July 2019 provides only limited time to communicate changes to customers and other stakeholders.

[5] Australian Competition and Consumer Commission (2018) *Restoring Electricity Affordability and Australia's Competitive Advantage: Retail Electricity Pricing Inquiry—Final Report,* July 2018, www.accc.gov.au

A.2 Our network and our customers

Our electricity distribution network

Ausgrid is a key element of the electricity supply chain that delivers electricity to customers' premises. We are often called 'the poles and wires'. Once power is generated, it is transported as high-voltage electricity over long distances by TransGrid.



Customers
1.7 million

Area
22,275 km²

Number of power poles
500,000

Length of powerlines and underground cables
50,000 kms

Large electricity substations
230

Small distribution substations
30,000

Employees
3,600

Our network then transforms it into lower voltage electricity at subtransmission and zone substations. This electricity is again transformed at local distribution substations, so it can be supplied to customers' premises. We manage more than 230 subtransmission and zone substations, 30,000 distribution substations, 50,000 kilometres of power lines and 500,000 power poles. These assets, along with our depots and other properties, are known as our regulated asset base and are worth approximately $15.7 billion.

Our customers – meter types and tariffs

The 1.7 million customers connected to the Ausgrid network have a diverse set of needs and preferences. Our customers range from small residential households consuming about 5 megawatt hours (MWh) a year to large industrial customers consuming more than 40 gigawatt hours (GWh) a year.

Residential customers are 90% of our customers, but businesses account for 66% of energy consumption. Our customers have a range of meter types, and therefore a range of tariffs, depending on whether the meter supports a more cost reflective tariff. For instance, over 500,000 customers of our 1.7 million customers are on a TOU or TOU capacity tariff. The number of our customers with interval or better metering is expected to increase to over 1 million in 2024.

Table A2.1 summarises our residential and small business customers by meter type and tariff.

Table A2.1. Customers by tariff and meter type in 2018/19

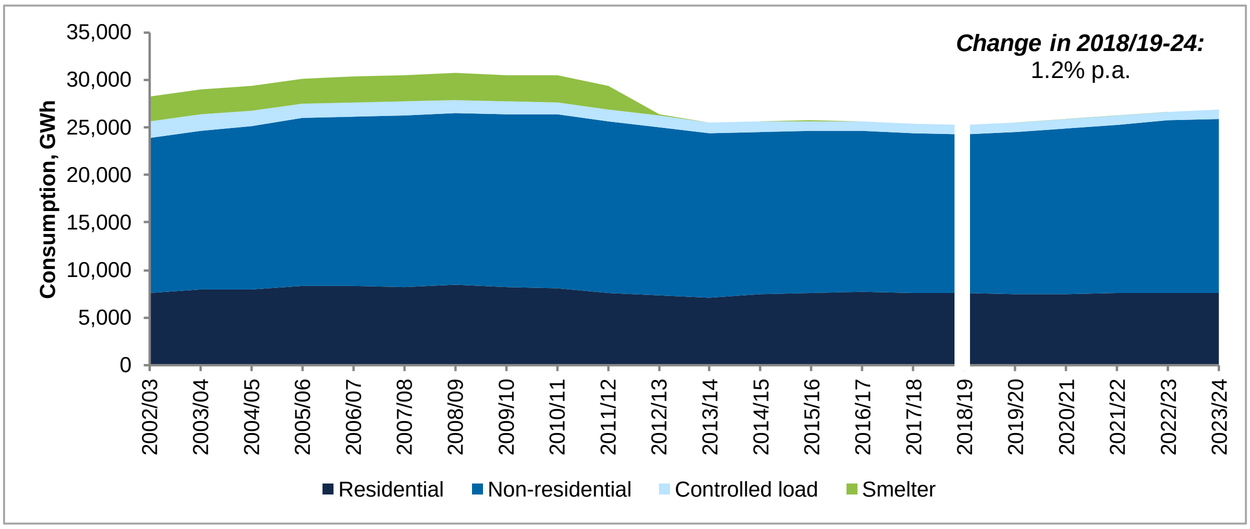
Customer and current tariff	Type 6 (Accumulation)	Type 5 (Interval)	Type 4 (Smart)	Total
Residential				
EA010 Non-TOU	1,075,000	0	0	1,075,000
EA011 Transitional TOU	0	80,000	70,000	150,000
EA025 TOU	0	285,000	50,000	335,000
Total residential customers	**1,075,000**	**365,000**	**120,000**	**1,560,000**
Small business				
EA050 Non-TOU	67,000	0	0	67,000
EA051 Transitional TOU	0	2,000	1,200	3,200
EA225 TOU	0	66,000	3,000	69,000
Total small business customers	**67,000**	**68,000**	**4,200**	**139,200**

Note: Residential customers rounded to nearest thousand.

Forecast energy consumption

Figure A2.1 shows our historical and forecast energy consumption by segment.

Figure A2.1. Ausgrid: Historical and forecast energy consumption



Source: Attachment 10.15 Energy Volume Forecast, January 2019.

Integrating pricing and demand management

Over the last 15 years, we have developed a suite of demand management, or non-network, solutions to complement network pricing to manage customer demand and maintain supply reliability, at least cost. The demand management solutions currently available include the use of embedded generation, customer power factor correction, dynamic peak rebate offers and direct load control of customer appliances, such as hot water systems, pool pumps and air conditioners.

The load control of air conditioners offers significant opportunities to reduce network costs since air conditioning load is a significant driver of peak demand. Our CoolSaver air conditioner demand response trial[6] has both proven the viability of the demand response technology introduced as part of Australian Standard AS4755, and the willingness of customers to reduce their demand when given an incentive. Changes in technology, such as energy storage, smart meters and energy management systems, are expected to increase the number of viable, cost effective solutions available.

Our demand management solutions are supported by our network pricing structures, which encourage customers to make efficient decisions on how they use the network and provide a foundation for introducing demand management programs. Our existing network pricing and demand management solutions complement each other in several ways:

- **Controlled load pricing**, in conjunction with load control equipment, can be used to shift appliance usage from peak periods to off-peak periods. Ausgrid has around 500,000 customers on controlled load tariffs, which contributes to an overall system peak demand reduction of 300 MW in winter and 100 MW in summer. These tariffs offer the potential for modifications in scheduling where specific local needs are identified.

- **Time of use capacity pricing** is mandatory for all medium to large business customers (>40 MWh a year), and accounts for approximately half of the electricity consumption from all our customers. Importantly, these capacity charges provide a price signal to encourage customer investment in power factor correction, one of the lowest cost demand management solutions that can be implemented, and the availability of interval data supports the use of a dynamic peak rebate offer to customers.

- **Time of use tariffs –** Ausgrid first introduced time of use pricing over ten years ago and over 500,000 of our 1.7 million customers are on a time of use or time of use capacity tariff. Although the lack of remote communications from Type 5 metering has hampered the introduction of more innovative tariff options to certain customer segments, the expansion of smart meters in the coming years is expected to offer significant opportunities for demand management. Rebate offers like the dynamic peak rebate or air conditioner load control may help defer network investment. The number of customers with interval or better metering is expected to increase to over 1 million in 2024.

We will continue to monitor the use of cost reflective tariffs, including our new demand tariffs, and assess the impact on customer usage patterns. Where customer demand is projected to change at a rate different from the past, we will develop and introduce a post model adjustment procedure to include in our demand forecast.

We note that as the number of customers on time of use or time of use capacity tariffs has grown steadily from close to zero in 2004 to over 500,000 residential and business customers in 2019, we now have 75% of our total energy volume in 2019 consumed by customers with cost reflective pricing in place. With our revised Tariff Structure Statement, we expect this coverage to increase to approximately 85% of our total energy volume by the end of the regulatory period in 2023/24. As the coverage of cost reflective network prices across total energy volume is expected to grow at a slower rate than the historical trend, we expect the historical econometric and spatial trends used to derive our demand forecast capture the demand response effect associated with cost reflective network pricing.

[6] *CoolSaver* is an initiative in which Ausgrid installs a signal receiver in a customer's air conditioner that allows Ausgrid to remotely activate the air conditioner's in-built power saving modes. Customers receive an upfront and ongoing reward for joining CoolSaver. The program began in summer 2013/14, and was promoted in selected suburbs in the Central Coast, Lake Macquarie and Maitland parts of our network. The initial program was completed in summer 2016/17 and further details including an interim report are on our website here. During the 2019-24 regulatory period Ausgrid is planning to further explore demand response trials using modern energy efficient air conditioners that are internet enabled.

A.3 Our customer consultation

Our process for customer consultation on pricing reform includes our Customer Consultative Committee, and our new Pricing Working Group. Customers also provided feedback on our Initial Proposal during its development and through submissions to the AER.

Customer Consultative Committee

The Customer Consultative Committee is the main consultative body we use to provide customer and external stakeholder perspectives on our plans, policies and service delivery, our regulatory submissions and the regulatory framework; and ensure appropriate and effective customer and stakeholder engagement. Box A3.1 lists the current members and observers.

Box A3.1. Customer Consultative Committee members and observers

- Council on the Ageing NSW
- Energy & Water Ombudsman NSW
- Energy Consumers Australia
- Ethnic Communities Council NSW
- Major Energy Users
- NSW Council of Social Services
- Public Interest Advocacy Centre
- St Vincent de Paul Society
- Total Environment Centre
- Consumer Challenge Panel (observer)

Pricing Working Group

Since the submission of our Initial Proposal in April 2018, we have set up a new Pricing Working Group to guide our pricing reforms. The Pricing Working Group had multiple working sessions in late 2018 to discuss the pricing reforms in our Revised Proposal. The Pricing Working Group helped us develop the pricing strategy in our Tariff Structure Statement that fairly recovers the costs of providing network services, while also giving customers transparent price signals that enable them to benefit from more efficient use of the network. This strategy now includes demand tariffs for residential and small business customers.

Members of the Pricing Working Group are the AER Consumer Challenge Panel, Energy Consumers Australia, Energy Users Association Australia, NSW Business Chamber, Public Interest Advocacy Centre, St Vincent de Paul Society and Total Environment Centre.

The path towards cost reflective tariffs

The customer consultation on our Initial Proposal and in developing our Revised Proposal identified challenges in achieving cost reflective tariffs.

In our Initial Proposal and our Tariff Structure Statement, we did not propose residential and small business demand tariffs from 1 July 2019. Our initial engagement with customers and stakeholders made clear there were mixed, conflicting and strongly held views by customers, customer advocates, Ausgrid and pricing experts on whether demand price structures would deliver more affordable, reliable and sustainable outcomes for our customers.

In response to the AER's Draft Decision, stakeholder submissions to our Initial Proposal and the feedback received from consumer representatives, we accelerated our proposed tariff reform by proposing a set of demand tariffs for residential and small business customers from 1 July 2019.

Customer input on our Revised Proposal

Our Revised Proposal is compatible with *Pricing Directions: A Stakeholder Perspective* developed by Energy Consumers Australia, Public Interest Advocacy Centre, Consumer Challenge Panel and Total Environment Centre (Attachment 10.14, unchanged from our Initial Proposal).

We agree with Pricing Directions that the endpoint for pricing reform changes through time to reflect changing circumstances, new information and evolving customer preferences. We agree with Pricing Directions that it is important that our pricing strategy is adaptive to change as new information comes to light.

We are grateful for the efforts of Energy Consumers Australia, Public Interest Advocacy Centre, Consumer Challenge Panel and Total Environment Centre in developing *Pricing Directions: A Stakeholder Perspective* which provides guidance on the design of an efficient pricing structure and the matters that networks should take into account when designing them.

We thank the Pricing Working Group for their support and working with us to create the Tariff Structure Statement in our Revised Proposal.

A.4 Our pricing reform

Cost reflective pricing and balancing objectives

We are committed to transitioning to efficient, cost reflective tariffs in a manner that best promotes the long-term interests of our customers, but recognise the efficient pricing outcome is constantly changing. Our customers' preferences and technology are changing, altering the way our customers use our network, the costs imposed on our network, and the most efficient means of providing the services our customers expect. In practical terms, tariff efficiency is an objective that we may be constantly working towards, without ever achieving in full, since it is always changing.

Cost reflective pricing must both:

- signal to customers future network costs that could be avoided and
- recover the historical cost of the network in a manner that has as little distortionary effect on customer behaviour as possible.

Encouraging efficient use of the network

Cost reflective pricing encourages customers to use our network efficiently by signalling to them the future costs arising from further use of our network, which enables them to decide:

- whether using our network best meets their needs at the lowest possible cost; or
- whether investments in distributed energy resources and energy efficiency initiatives can better meet their needs at a lower cost, which benefits all customers.

Importantly, the level of future costs that could be avoided varies considerably across the day. We estimate that avoidable costs:

- are equal to approximately $56/kW during the peak period; but
- are very close to zero outside of the peak period, because there is excess capacity on our network at those times.

This means that, at a very high level, any changes to the network use outside the peak periods have very little impact on network operating costs. We established the peak periods for residential customers as 2-8 pm in summer and 5-9 pm in winter. Outside these periods, our tariffs should encourage customers to use the network, as there is little or no additional network cost.

For example, the additional network costs imposed by customers running their air conditioners on hot summer nights after 8 pm (when there is excess capacity on our network) is low. If this is something customers value, we do not want to unnecessarily discourage them from using our network by sending price signals that are much above the cost reflective level.

Our current non-peak variable energy charges – the shoulder and off-peak price – overstate the very low level of future avoidable network costs in the shoulder and off-peak periods.

Therefore, our pricing reforms which include reducing shoulder and off-peak energy prices will better reflect the additional costs of providing network services at those times, which will encourage the efficient use of our network and increase our capacity utilisation. In passing through savings for the first year of the 2019-24 regulatory period, we reduced shoulder and off-peak energy consumption prices where possible.

Encouraging efficient investments in new technologies

Cost reflective price signals also play an important role in assisting our customers to make efficient investments in distributed energy resources (DER) and undertake efficiency-enhancing activities. This is particularly important in the context of rapidly changing technology. One of the objectives of the tariff reform is to remove the distortions that current tariff structures have for optimal investment in new technologies. The tariffs should also enable a fair allocation of residual costs between customers with similar load profile irrespective of technology.

Network prices feed into customers' investment decisions signalling the hypothetical network bill savings that can be achieved from an investment in DER. While not all customers invest in DER for purely economic reasons, an economically rational customer would invest in DER if they estimate benefits from this investment in Net Present Value terms.

To establish these likely benefits, the customer would typically evaluate the upfront cost of installing the technology with the amount and timing of the stream of savings they are likely to receive from the investment. Government policies and assumptions on their direction tend to heavily influence this evaluation, and hence the investment decision.

The savings are from the retail bill, as this is the only bill that the customer faces directly. These savings flow from the three components of the retail bill – network charges, wholesale energy and retail component. The degree to which changes in network charges are passed on to the customers by their retailers is an open question.

However, assuming that the retailer passes through the price signal embedded in the network charges, our network charges should encourage optimal investment in DER. That is, the savings in network charges to the DER customer at times where there are little savings in our network costs from the customer's DER, should be little if any. In principle, with fully cost reflective network pricing, customers will invest in DER when the cost of that investment is less, on a Net Present Value basis, than the avoided network costs plus generation and retail costs resulting from that investment (together equal to their total retail bill saving).

This is an efficient Net Present Value positive investment in DER meeting that customer's needs at a lower cost. The benefit from this customer investing in DER would accrue to other customers as well if the future network costs are lower to all customers.

However, if our prices are above cost reflective levels then we signal to customers that the future network costs that could be avoided by an investment in DER are much higher than they really are. This means that a customer investing in DER may realise a network bill reduction that exceeds the resulting reduction in future network costs. This is an inefficient investment in DER since the costs avoided are lower than the costs of investment and, in this case, other customers incur the grid costs avoided by the customer with distributed energy resources.

Reductions in the use of our network outside the peak period generally result in very low, if any, avoided future network costs. However, our current shoulder price in particular is significantly above the cost reflective level. Since the vast majority of solar PV generation occurs outside the peak period, this means that future investors in solar PV will receive a network bill reduction that typically far exceeds the avoided future network costs. The difference must then be recovered from other customers, which creates inequities between adopters and non-adopters of solar PV and other DER.

On the other hand, introducing demand tariffs and lowering non-peak energy charges will encourage more efficient investment in distributed energy resources. New tariffs provide incentives to invest in DER targeted at reducing the use of our network during peak, rather than non-peak periods. For example, reducing shoulder charges encourages customers to install west-facing solar PV installations that better assist in reducing the use of the network later in the day, i.e., during peak periods. The demand charge peak period of 2-8 pm in summer creates incentives to install a battery to manage the maximum demand in peak period. Demand tariffs support take-up of smart home technologies. With more customers managing peak demand either by taking control of their load or letting a third party control that load for them, the network as a whole can manage the peak demand better, ensuring network stability, saving on future augmentation costs and delivering the best long-term outcome for all customers.

Introducing demand tariffs

We support customers having control of their network bills by changing their behaviour in a way that avoids future network costs. Customers can do this by reducing their use of the network during peak periods which drives our costs. For this reason, our costs are based on an estimate of the long run marginal cost of using the network during the peak period. We encourage customers to manage their network bill by changing their behaviour in a way that reduces their use of the network during the peak period which assists in avoiding future network costs.

Our new set of demand tariffs with a demand charge, explained in Section A.1, will encourage customers to reduce their peak demand and reduce future network costs for all customers.

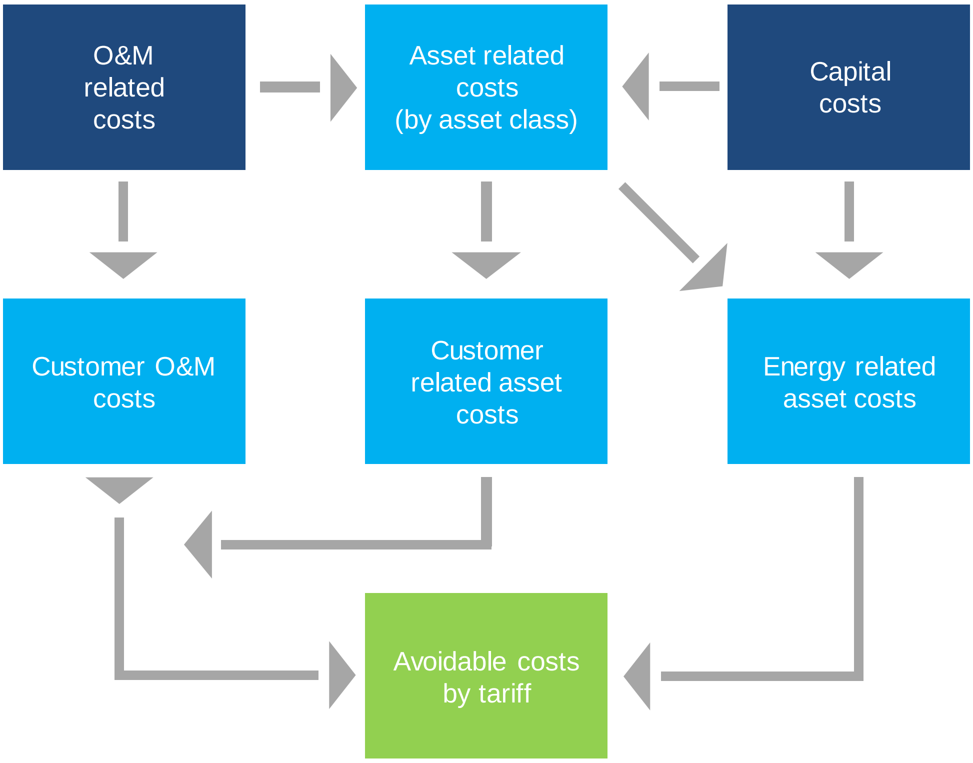
A.5 Our pricing principles

Our approach to pricing principles is supported in Attachments 10.03 Long Run Marginal Cost model, 10.04 Long Run Marginal Cost methodology report, 10.05 Tariff model, 10.07 Price elasticity, 10.08 Transmission pricing methodology and 10.09 Methodology for avoided TUOS charges, unchanged from our Initial Proposal.

Revenue is between standalone and avoidable costs

Our methodology for estimating avoidable costs at the tariff class level over the regulatory control period is summarised in Figure A5.1 below.

Figure A5.1. Calculating avoidable costs



In the context of the National Electricity Rules, the concept of standalone cost is readily applicable as an estimate of the costs of serving a tariff class alone. We have estimated the standalone cost for each tariff class by assessing and categorising its capital and operating costs on the basis of the following two dimensions as follows:

- **Whether costs are direct or indirect –** where capex and operating costs are categorised as:
  - 'direct' or 'avoidable', i.e., the cost can be attributed to a specific group of users and would not be incurred but for those users; or
  - 'indirect' or 'shared', i.e., the cost is common to multiple groups of users.

  For example, some customer operations can be directly attributable to individual customers. In contrast, operational expenditure costs are generally indirect, such as the cost of debt raising cannot be attributed to specific customers or customer groups.

- **Whether costs are fixed or variable –** where capex and operating costs are categorised as either:

- ‘variable’, i.e., the cost tends to increase in proportion to the scale at which the service is provided; or
- ‘fixed’, i.e., the cost is independent of the scale at which the service is provided.

For example, maintenance and repair costs are considered variable as they are likely to be highly dependent on the physical size of the network. In contrast, incentive payments are likely to be relatively independent of network characteristics such as the number of customers or maximum demand.

Having categorised individual costs, the next step is to use a weighting mechanism such as customer numbers or consumption to attribute cost categories to each tariff class. In equation form, this process can be expressed as follows:

$$\mathit{Stand\text{-}alone\ cost}_i = \mathit{Avoidable\ cost}_i + \mathit{Fixed\ indirect\ costs} + \sum_{j=1}^{n} \beta_{i,j} \mathit{Variable\ indirect\ costs}_j$$

where

- i represents each of Ausgrid’s tariff classes;
- *Stand-alone cost*$_i$ is the stand-alone cost to serve customers on tariff class i;
- *Avoidable cost*$_i$ *i*s the avoidable cost to serve customers on tariff class i;
- *Variable indirect costs*$_j$ represents each of Ausgrid’s variable indirect operating and capital cost categories; and
- $\beta_{i,j}$ is the scaling factor (some value between zero and one) applied to cost category j.

We are satisfied that our efficient tariff outcomes are free of economic subsidy since the revenue outcomes based on these prices lie on or within the bounds of standalone and avoidable cost at the individual tariff class level.

We are satisfied that the indicative prices are free of economic subsidy given that our analysis in Table 4.1 in our Tariff Structure Statement shows that the revenue outcomes based on these prices lie on or within the bounds of standalone and avoidable cost at the individual tariff class level.

Our efficient peak prices are based on long run marginal cost

The Rules require each tariff to be based on the long run marginal cost (LRMC) of providing the relevant service to the retail customers assigned to that tariff.

LRMC is a forward-looking concept and amounts to a measure of the additional cost incurred as a result of a relatively small increase in output, assuming all factors of production are able to be varied. Setting network tariffs by reference to LRMC encourages customers to use our services where the benefit they derive exceeds the cost of providing the relevant services.

Since LRMC is a forward-looking concept concerned with the cost of an incremental increase in output, it does not reflect historical costs associated with the existing network. Therefore, setting prices equal to LRMC, generally, would not allow the recovery of Ausgrid’s efficient costs. In other words, if each tariff was set equal to LRMC there would be a residual amount of efficient costs to be recovered.

A standard method for estimating LRMC is the average incremental cost (AIC) approach. An AIC approach estimates LRMC by equating, in present value terms, the average change in forward looking growth and connections expenditure resulting from a change in demand. Our estimate of LRMC for different tariff groups connected to our network using the AIC approach is set out below in Table A5.1.

Table A5.1. LRMC estimates (growth and connections)

Tariff group	Customer type	Metering type	LRMC ($/kW)	No. of peak hours	LRMC Peak (c/kWh)	LRMC Anytime (c/kWh)
Low Voltage	Residential & Business	Basic	56.2	8,766		0.64
Low Voltage	Residential & Business	Interval	56.2	880	6.39	
High Voltage	Business	Interval	36.0	880	4.09	
Subtransmission Voltage	Business	Interval	6.4	880	0.73	

In response to feedback from the AER on whether avoidable replacement expenditure should be included in our estimate of LRMC, we engaged Deloitte to develop a new methodology that estimates the LRMC associated with replacement capital expenditure. Our proposed approach to estimating LRMC is set out in the Deloitte report included at Attachment 10.04.

Using this methodology, we derived estimates of LRMC for replacement capex by tariff group using a perturbation approach and converted those estimates into seasonal peak prices. We present these estimates and efficient seasonal time of use price levels in the table below.

Table A5.2. LRMC estimates (replacement)

Tariff group	Customer type	Metering type	LRMC Peak (c/kWh)	LRMC Shoulder (c/kWh)	LRMC Off Peak (c/kWh)	LRMC Anytime (c/kWh)
Low Voltage	Residential & Business	Basic				1.41
Low Voltage	Residential	Interval	3.14	1.70	0.55	
Low Voltage	Business	Interval	3.14	2.08	0.72	
High Voltage	Business	Interval	3.14	2.08	0.72	
Subtransmission Voltage	Business	Interval	1.25	0.83	0.29	

These two approaches for estimating the forward looking LRMC of Ausgrid's network are broadly additive. However, a difference in the tariff groups connected to our network and the causal relationship between demand and expenditure means that the results of the two LRMC approaches should be interpreted differently. That is:

- under the AIC approach, there is a clear causal relationship between demand growth and the new growth and connections expenditure, i.e., growth and connections expenditure is triggered by demand growth; while
- under a perturbation approach, demand is one of a range of factors (including health, safety and environmental considerations) that determine the timing of when existing assets are replaced, i.e., the decision to replace an asset will depend on a range of

factors including the level of unserved energy, the health and safety of staff and public as well as our obligation to protect the environment.

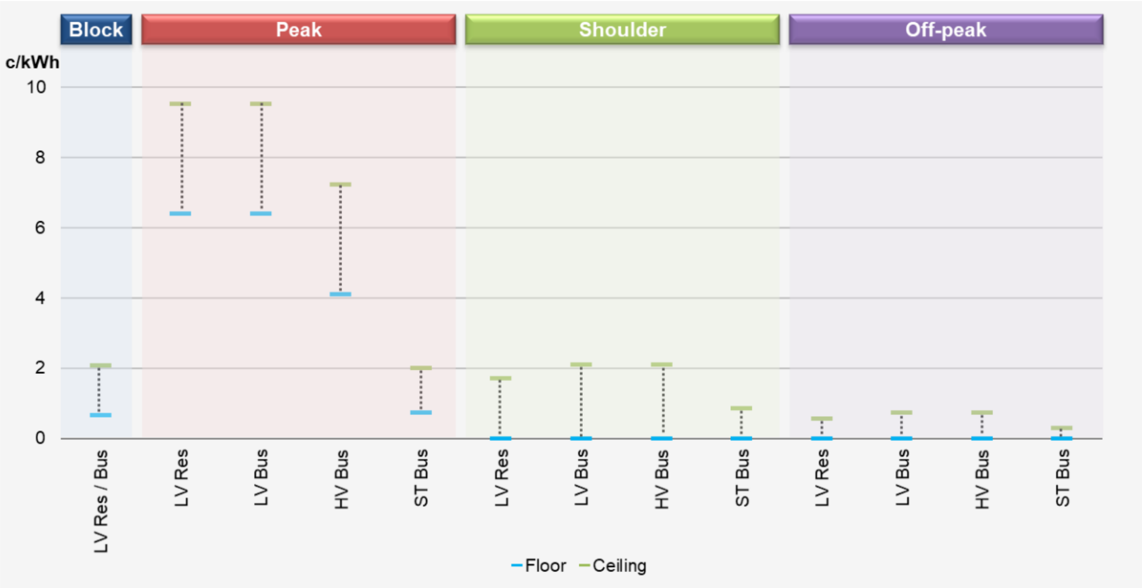
This difference in the causal relationship between demand and expenditure means that:

- the AIC approach provides a lower bound (floor) for the LRMC estimate for Ausgrid's network since there is a clear nexus between growth in peak demand and requirement for future expenditure on growth and connections assets; while

- the AIC LRMC estimate plus perturbation LRMC estimate together should be interpreted as an upper bound (ceiling) for the LRMC of Ausgrid's network as the perturbation approach estimates the LRMC under the assumption that replacement expenditure is solely driven by considerations of unserved energy (with no weight given to health, safety and environmental considerations).

As a consequence, our approach does not provide a point estimate of the LRMC for our network. Instead our approach estimates a reasonable range for the LRMC. Figure A5.2 sets out a reasonable range for the LRMC for different tariff groups.

Figure A5.2. Long run marginal cost range for different tariff groups



Our proposed departure from efficient pricing

We explain below the key departures from theoretically efficient pricing implicit in our proposed pricing strategy.

We propose to depart from theoretically efficient tariffs by continuing to adopt postage-stamp or location-neutral pricing, since our consultation for our Initial Proposal established that our customers do not support locational pricing.

We propose to gradually reduce a proportion of historical costs recovered from variable energy charges. The speed of transition is being driven by the need to manage customer bill impacts.

We also propose to transition our peak prices to efficient long run marginal cost based price levels through time to avoid unacceptable customer bill impacts and smooth changes in long run marginal cost through time.

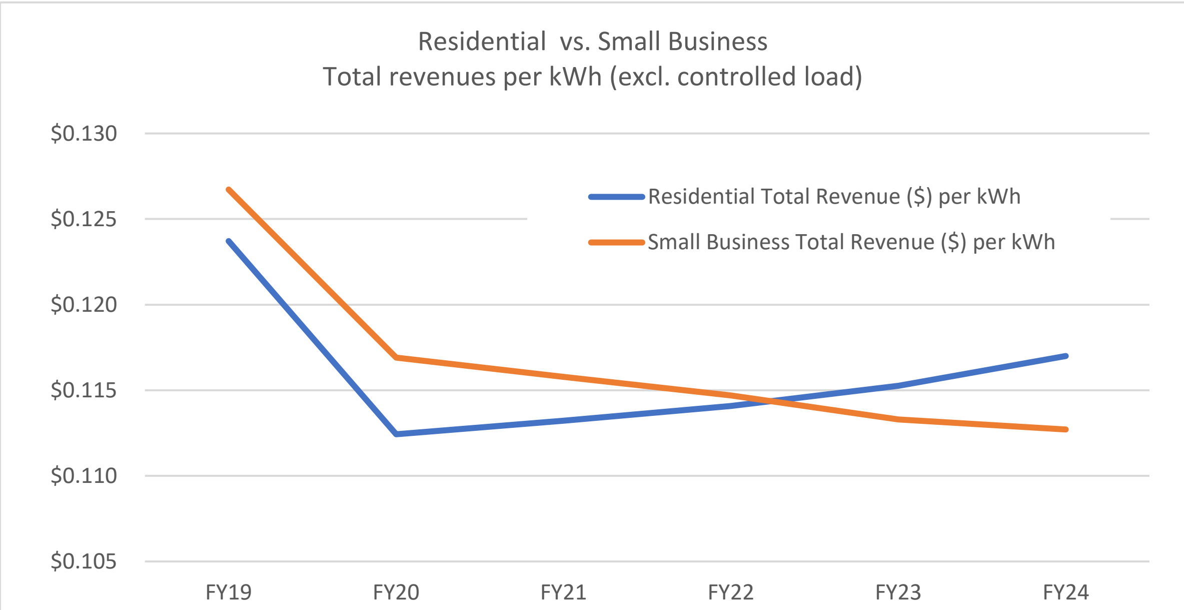
Prices for small business customers

In its draft decision the AER highlighted a disparity between residential and small business prices, stating:

> Each of the NSW distributors' indicative pricing schedules include high tariff levels for small business when compared to residential customers. We are seeking further information from Ausgrid about why it proposes higher tariff levels for small business customers.

At an overall level, Ausgrid's small business customers pay 2.4% more than residential customers (on a total $/kWh basis) based on prices and predicted volumes in 2018/19. This differential has arisen over time and is linked to progression of legacy tariffs across both groups. With the accelerated adoption of more cost reflective prices Ausgrid will be unwinding and ultimately reversing this differential, moving each class closer to a more cost reflective level overall while minimising any impacts on customers in other classes. Figure A5.3 below shows how average prices (defined as total revenues divided by total volumes) collected from small business customers will change relative to residential customers over the regulatory period.

Figure A5.3. Comparison of overall prices: residential vs. small business



Individually calculated tariffs

As set out in our ES7 Network Price Guide (Attachment 10.06), our policy states that customers on a published network tariff that have network usage greater than the 10 MW or 40 GWh a year threshold over a period of a full financial year can apply to be reassigned to an individually calculated tariff.

When connecting a new large customer who is likely to exceed the 10 MW/40 GWh a year threshold, we evaluate the customer's technological needs and requirements. The customer typically funds the dedicated assets for its connection. We establish the shared assets that the customer requires, and set tariffs to ensure that any additional costs specifically associated with supplying a large customer are not borne by the general customer base. We would establish a new individually calculated tariff (ICT) on this basis. Because of this, we do not allow a customer on an individually calculated tariff to opt-out from the tariff, once calculated, into a published tariff.

Individually calculated tariffs reflect location specific costs that large customers create for our distribution network. A published tariff is a postage-stamp tariff calculated for the whole network operation area. A geographic averaging of costs is embedded in our published tariffs, by tariff class. The purpose of the individually calculated tariffs is to prevent cross-subsidies between the general customer base and large customers with special, and often unique, needs. These tariffs also prevent cross-subsidies between large users with special servicing requirements or locational price differences, and an average smaller user within the tariff class.

We have about 60 customers on individually calculated tariffs calculated at various points in time. Some of them are legacy tariffs. We have been reviewing the pricing parameters for these customers and transitioning them to prices that are more reflective of their current contribution to the system peak demand.

Customers on individually calculated tariffs are billed for their share of transmission use of system (TUOS) charges incurred at their actual connection point. Our recent approach has been to move our existing individually calculated tariff customers closer to the listed distribution use of system (DUOS) component of their prices. Where there is a material gap from the listed DUOS component for legacy reasons we are transitioning those customers over time at a rate such that their price change does not exceed 7% per annum for each individual customer. However, where customers have several NMIs, individual NMIs may exceed this threshold.

Allocation of residual costs to tariffs

The AER asked us to provide more information on allocating residual costs.

The up-front costs required to provide the services our customers want to use mean that prices based on future avoidable costs (LRMC) alone are not sufficient to recover our total efficient costs, as determined by the AER.

We must therefore allocate the remaining AER-approved costs, often referred to as residual costs, to particular tariffs and then across the charges that comprise each tariff. The price level for a particular charge reflects the efficient costs allocated to that charge divided by the applicable quantity forecast.

To avoid unacceptable customer bill impacts arising from the reforms proposed in our Tariff Structure Statement, we will broadly maintain the existing share of residual costs allocated to each tariff class, subject to the bounds established by the National Electricity Rules.[7]

The National Electricity Rules require us to set prices to recover from customers on a particular tariff only the total efficient cost of providing services to those customers.[8] Therefore, we allocate residual costs to each tariff such that, when added to revenue from LRMC-based charges, we recover the total efficient cost of providing those services.

It follows that calculating the total efficient cost of providing services to customers assigned to each tariff is a key element of the price-setting process, since it guides the allocation of residual costs to tariffs. For this reason, we propose material improvements to our residual cost allocation methodology that are founded on refinements to our calculation of the total efficient cost of providing services to customers on each tariff.

We estimate the total efficient cost of providing services to customers assigned to each tariff based on their relative contribution to maximum demand, a key driver of our efficient costs.

[7] National Electricity Rules, clause 6.18.5(e).
[8] National Electricity Rules, clause 6.28.5(g).

We estimate the relative contribution of each tariff to maximum demand in each future year by:

- calculating the contribution of each tariff to historical maximum demand; and
- adjusting those historical relative contributions for expected changes in the number of customers assigned to each tariff in future years.

We then calculate the total efficient cost of providing services to customers assigned to a tariff equal to its contribution to maximum demand for the relevant tariff class multiplied by the total efficient cost for that tariff class.

Finally, we allocate residual costs to each tariff so that, when combined with revenue from the LRMC based charge, we recover the total efficient cost of providing services to customers assigned to that tariff.[9] Where the resulting allocation would create unacceptable customer bill impacts, we propose to transition the costs recovered from that tariff to efficient levels over time.

We adjust the methodology to recognise that customers in the higher voltage classes do not drive the costs of our lower voltage distribution network. Their contribution to the total network charges would be expected to be lower than their share in the system peak demand.

Allocation of residual costs to charging parameters

Having allocated residual costs to each tariff, we then allocate those residual costs to the charging parameters that comprise that tariff.

The Rules require us to allocate residual costs in a manner that minimises distortions to our efficient LRMC based prices, which necessitates recovering residual costs from those charges for which customers are least responsive to changes in price. For example, *Pricing Directions: A Stakeholder Perspective* notes that[10] 'Economic efficiency is enhanced if the remaining revenue [residual costs] are raised through charges that have as little impact on behaviour as possible'.

We commissioned a study by HoustonKemp that found customers are less responsive to changes in price during the peak period, as compared with non-peak periods.[11] HoustonKemp observed that, although recovering residual costs from fixed charges is optimal from a strict economic perspective:[12]

> …any allocative inefficiency arising from the recovery of residual costs during the peak period… would be relatively low, as compared with recovering those costs from the shoulder period.

Therefore, our proposed approach to allocating residual costs to charging parameters is directed at recovering, in a way that leaves the average customer's network bill unchanged:

- relatively more residual costs from demand charges and, in some circumstances, peak energy charges; and
- relatively less residual costs from inefficient non-peak energy charges.

The extent to which we recover more residual costs during the peak period, and less during the non-peak period, is guided by the avoidance of unacceptable customer bill impacts.

[9] National Electricity Rules, clause 6.18.5(g)(1).
[10] Attachment 10.14: Stakeholders (2017) *Pricing Directions: A Stakeholder Perspective*, p. 4 footnote.
[11] Attachment 10.07: HoustonKemp (2017) *How do electricity customers respond to price signals?*, December, p. 20.
[12] Attachment 10.07: HoustonKemp (2017) *How do electricity customers respond to price signals?*, December, p. 4, 20.

Importantly, our proposed approach will:

- leave unchanged the network bill for the average customer
- encourage efficient investment in distributed energy resources by providing incentives for investments targeted at reducing the use of our network during peak periods
- avoid inequities between adopters and non-adopters of distributed energy resources that arise from inefficiently high non-peak energy charges
- reflect the views of some stakeholders that customers prefer variable charges to fixed charges[13]
- ultimately, encourage customers to use our services in a way that best meets their needs, at least cost to the system as a whole, and hence to all customers connected to our network.

How we implement this approach

We implement our proposed approach by delivering to customers the cost savings we have achieved primarily through reductions to the shoulder and off-peak charges. We endeavour to generally hold constant in real terms our existing fixed, peak energy and capacity charges on 1 July 2019.

For the reasons we explain above, economic efficiency is promoted by recovering a degree of residual costs from peak energy charges and so if the pure LRMC-based price is materially below the existing price level, we hold that current peak price constant in real terms. Similarly, the capacity charges applying to our larger customers have strong economic properties for recovering residual costs and so we intend to avoid any material reductions to those charges.

For fixed charges, we allocate residual costs for new tariffs to align with the charges currently faced by eligible customers. For small business customers in particular, we propose to reduce fixed charges by 5% in real terms in the first year of the regulatory period.

Specific information for our new demand tariffs

For our new demand tariffs (EA116 Residential and EA256 Small business) we recover residual costs from the fixed, flat energy and demand low season charges, whereas the demand high season charge is used to signal LRMC.

For our TOU demand tariffs (EA115 Residential and EA255 Small business), we recover residual costs from the fixed charge, demand high season, and demand low season charges, along with all time of use consumption charges. In other words, we also recover a degree of residual costs from the peak energy charge, which is set above the LRMC-based level. This also assists in managing the volatility in customer bill impacts that arises from changes in LRMC through time.

[13] Attachment 10.14: Stakeholders (2017) *Pricing Directions: A Stakeholder Perspective*, p. 4.

A.6 Our customer impacts

Our Revised Proposal appropriately balances the need to improve the efficiency of our network tariffs against the important requirement to consider the impact of these tariff reforms on our customers.

The impact on customers of our proposed network tariff reforms will vary depending on each customer's energy consumption level and profile, metering type and voltage level. The impact will also be influenced by how retailers pass through our network price signals to their customers and the extent to which customers are willing and able to respond to the proposed changes in the level and structure of our network tariffs.

Impacts depend on the response by retailers

To date retailers have typically passed through the structure and shape of network tariffs to their customers, adding margins to the various components on the network charge to recover their costs. A recent exception is a large retailer operating in our region chose not to pass through our seasonal time of use structure to their customers. Instead the retailer offered a non-seasonal time of use structure, where the retailer bears the risk associated with the seasonality in the underlying network tariff on behalf of those customers.

Retailers will have the choice to pass our new demand tariffs through to customers (as they have traditionally passed through the shape and structure of network charges) or offer more innovative retail products that use alternative price signals such as caps or rebates, or otherwise manage any risk associated with network charges on behalf of their customers the same way retailers currently manage wholesale price risk for customers.

These innovative retail products may start with a simple premium to reward retailers for taking on the additional risk from customers, but are likely to evolve rapidly to include products or mechanisms that more effectively hedge retailers' risk, allowing them to remain the competitiveness of their offer. As these more advanced products emerge, they will help achieve the aim of the underlying network tariff to reduce demand on our network at peak times and make the energy system lower cost for all.

Over time new technologies such as smart connected appliances and batteries are likely to play an ever increasing role in changing energy use patterns to optimise energy costs for consumers. The introduction of automated or remotely controlled devices will give retailers additional tools to manage a broader set of risks for customers and offer more innovative retail products. Even without these technologies, larger retailers will be able to offer innovative 'insurance' products, and hedge their risk through a portfolio approach across their customer base.

This transition will not be immediate, and it will take time for retailers to develop new products. During this time, clear communications to allow customers to understand and adjust their behaviour to respond to the new price signals will be critical.

If retailers choose to simply pass on the demand tariffs in the same shape and structure as the network tariff (as some are likely to do, particularly immediately after 1 July 2019), it will be important that customers understand how these new tariffs work and how they can most effectively respond to minimise the demand charges. This will require a collaborative approach to communications between ourselves, customer representative groups that have championed the change, and the retailers our customers use.

To aid this process we have started an extensive engagement process with the retailers in our area. This process will continue until 1 July 2019 when our new tariffs are introduced, and beyond, to ensure we understand how our new tariffs are being passed on to customers, and what communications can be undertaken (jointly branded or otherwise) to make the transition for customers as seamless as possible.

Impacts depend on the response by customers

Impacts on customers depend on the demand response by customers. Customers may continue their existing usage patterns, or they may respond to any new demand charges passed through by their retailer by flattening their demand. To respond efficiently, customers need to understand how their retail tariff is structured and how they can manage their consumption and demand to reduce costs. Our communication campaigns will focus on providing the information customers need.

We will also work with other retailers, customer groups and government representatives to ensure a set of complementary measures are available to manage impact, particularly for customers who require assistance, both before and after customers receive their first bill on their new tariff. See Section A.7 for further details.

Method for our analysis of customer impacts

To understand customer impacts, we have estimated the annual network bill outcomes based on customers' energy consumption and (where applicable) maximum demand for a representative sample of Low Voltage class customers based on a full year of 30 minute demand data from 2016/17. Impacts for High Voltage and Subtransmission class customers are based on data from all customers due to the small number of customers in each class. Solar customers in the sample have been excluded from the analysis where it is not possible for them to experience that tariff transition.

In all modelled scenarios, customers' total daily energy consumption and consumption in the peak, shoulder and off-peak time periods remains unchanged. We have modelled several options for residential and small business customers' response to the new demand charge:

- assuming customers do not change their behaviour in response to the new demand charge
- assuming customers reduce their maximum demand by 10%, by staggering their use within the demand window.

Studies on typical demand responses in climatic conditions comparable to Sydney are difficult to find. However, results from available studies show that customers exposed to a price signal in the form of a demand charge do make a demand response. Weighting the results of the available studies[14] by the number of customers in each suggests that a 10% demand response could be expected on average and, if anything, is likely to be a conservative estimate in a temperate climate. The 10% demand response is also prudent as different customers will have different demand characteristics and a 10% average response across all customers means, by definition, half achieving more and half achieving less.

The following sections present impacts for:

- Residential customers
- Small business customers
- Medium and large business low voltage customers
- High voltage customers (on listed tariffs)
- Subtransmission customers (on listed tariffs).

[14] The three studies are summarised, with references to the original studies, in: Hledik, Ryan (2014) Rediscovering residential demand charges, *The Electricity Journal*, 27(7), pp. 82-96.

The set of figures shows the impact for different groups of customers depending on their meter type and tariff, at the beginning of the regulatory period in 2019/20 and at the end of the regulatory period in 2023/24. Each figure has a summary table of the impacts including average annual bill impact, energy consumption, demand and average load factor.

Average load factor is the average demand as a proportion of the maximum demand in a year and is important in determining the impact of a demand charge. The average load factor for a residential customer is approximately 10%. Customers with a very low load factor have very peaky demand (and drive higher network costs than other customers with the same overall consumption but higher load factor) and are more affected by demand charges. Customers with a higher load factor are less affected.

Residential customer impacts

Based on Figure 2.3 in Section 2 of the Tariff Structure Statement showing the assignment of residential customers from 1 July 2019, the following figures show the impact on residential customers moving from their current tariff to a new tariff from 1 July 2019 and impacts at the end of the regulatory period in 2023/24.

Box A6.1 is a key to the set of residential customer impact figures including:

- Figures A6.1 to A6.5: the impact on customers on each of the tariffs in 2018/19 from 1 July 2019
- Figures A6.6 and A6.7: the impact on customers on flat tariff being assigned to a new demand (introductory) tariff due to meter failure after 1 July 2019, and the impact of being reassigned to the default demand tariff after 12 months
- Figure A6.8: the impact on customers being assigned to a demand tariff due to change from a flat tariff to a smart meter by customer initiated action after 1 July 2019
- Figure A6.9: the impact on TOU customers opting-in to a demand tariff due to change for any reason from an interval meter to a smart meter after 1 July 2019
- Figures A6.10 and A6.11: the impact on customers on the continuing non-demand tariffs (flat and TOU) of tariff price progression from 2018/19 to the end of the regulatory period in 2023/24
- Figures A6.12 and A6.13: the impact on customers on the two new demand tariffs of tariff price progression from 2019/20 to the end of the regulatory period in 2023/24.

Box A6.1. Key to residential customer impact figures

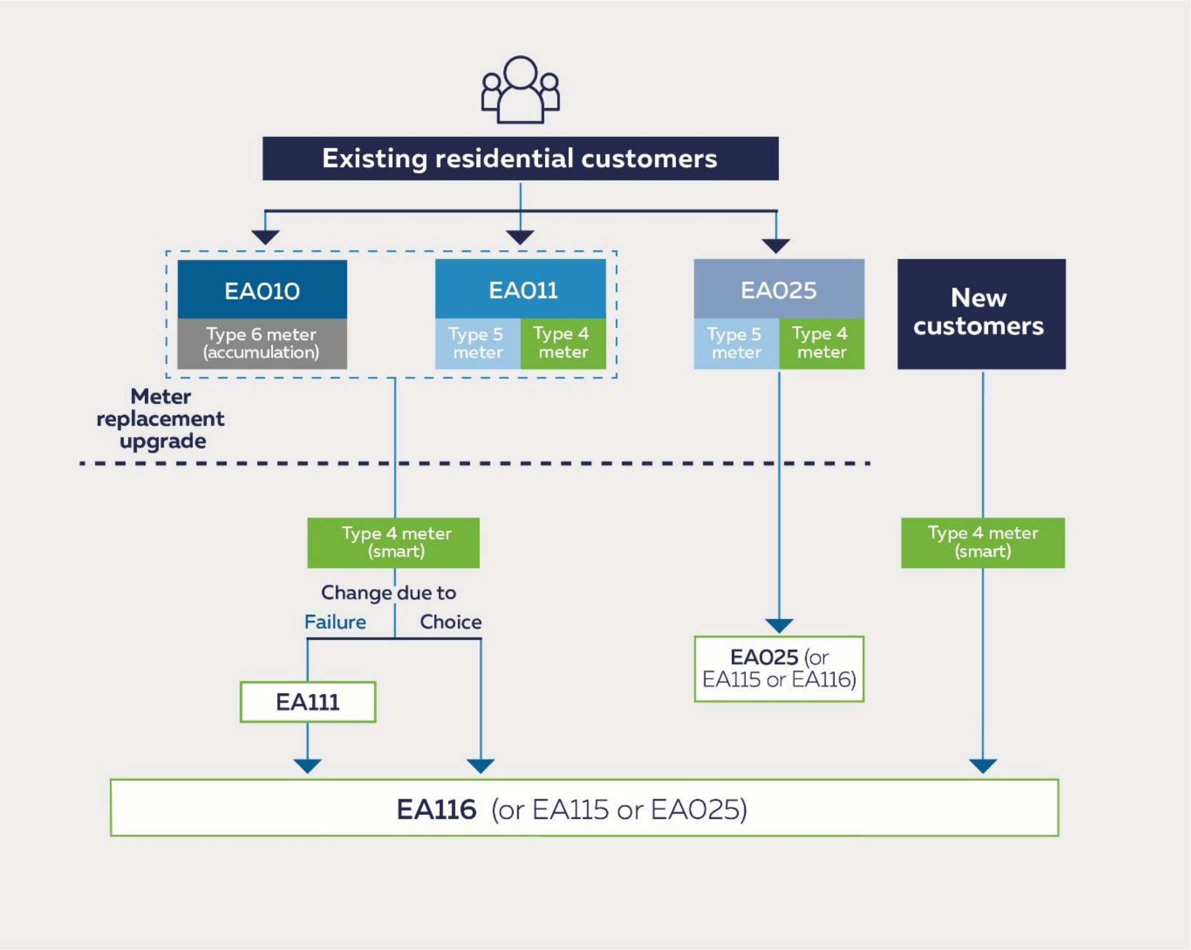
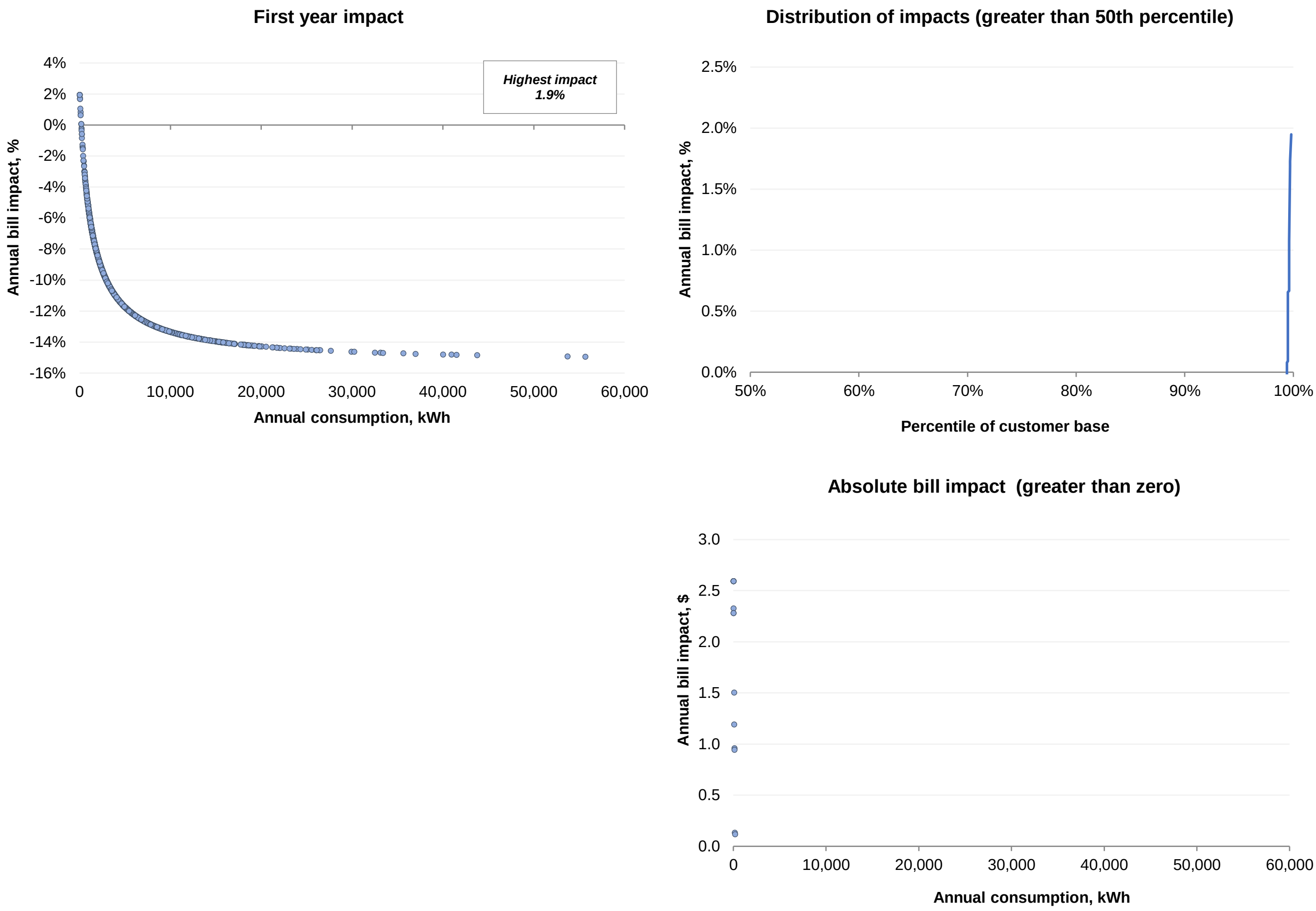
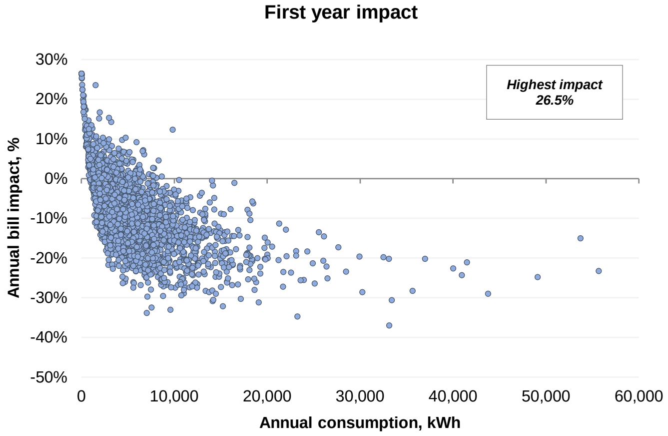


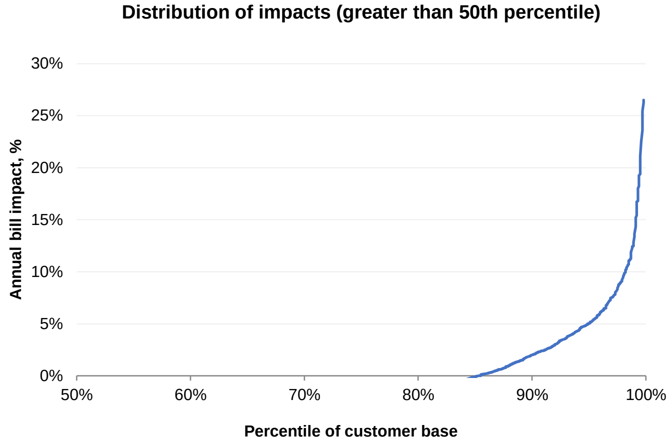
Figure A6.1. First year impact: EA010 Non-TOU/EA011 transitional TOU from 2018/19 to 2019/20

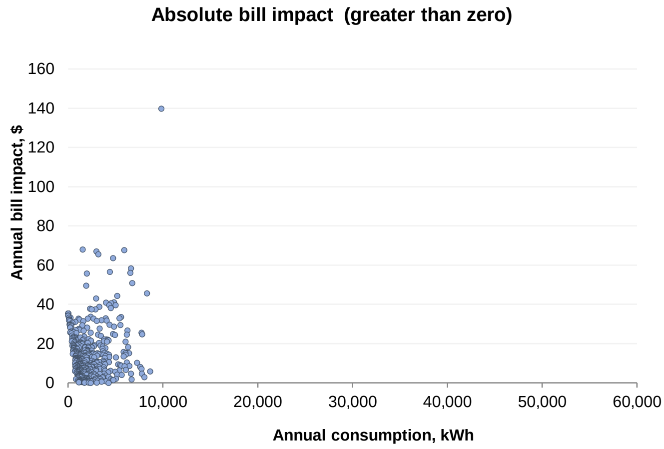


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	0.5%	0.0%	0.0%
Average annual bill impact, %	-10.5%	1.3%	N/A	N/A
Average annual bill impact, $	($77)	$2	N/A	N/A
Average annual consumption, kWh	5,117	50	N/A	N/A
Average maximum demand, kW	5.4	0.5	N/A	N/A
Average load factor, %	10.3%	0.6%	N/A	N/A

Figure A6.2. Opt-out of customers with interval meters from EA011 Transitional TOU to EA025 TOU on 1 July 2019

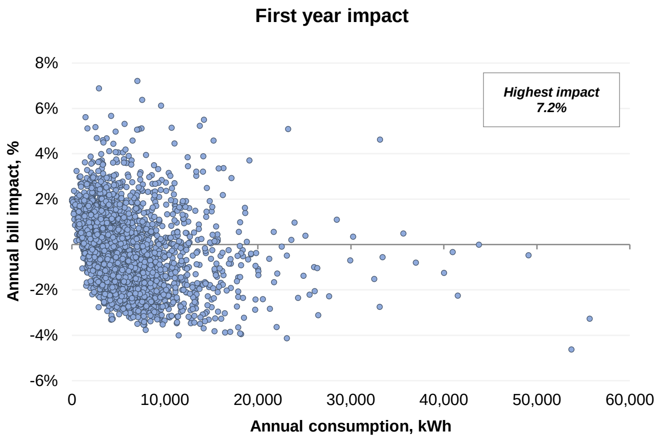


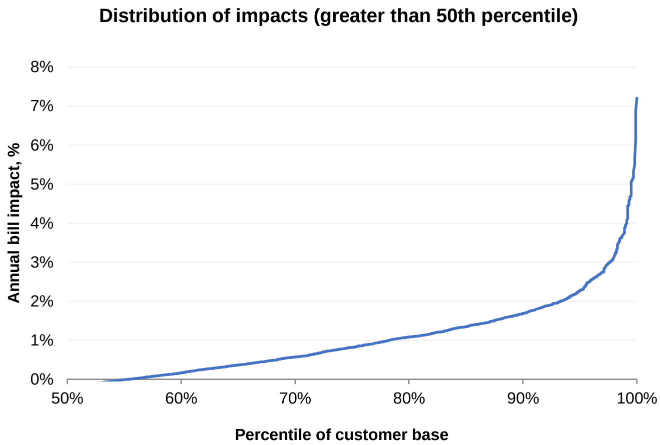


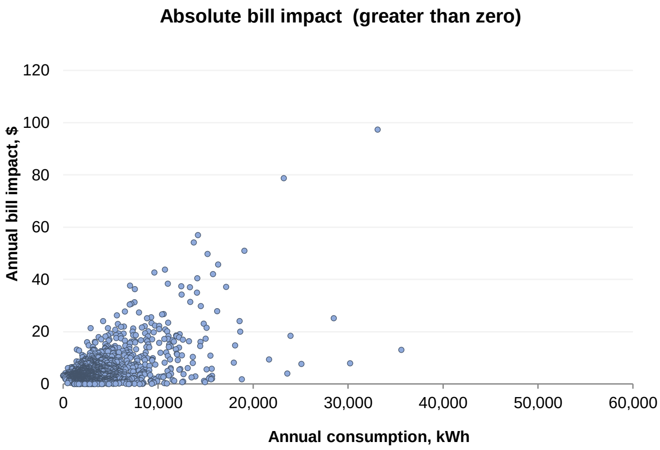


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	14.6%	1.8%	0.5%
Average annual bill impact, %	-8.2%	4.9%	16.3%	24.6%
Average annual bill impact, $	($75)	$14	$33	$36
Average annual consumption, kWh	5,189	2,199	858	148
Average maximum demand, kW	5.6	4.1	2.3	0.8
Average load factor, %	10.2%	6.1%	3.8%	0.7%

Figure A6.3. First year impact: EA025 TOU from 2018/19 to 2019/20

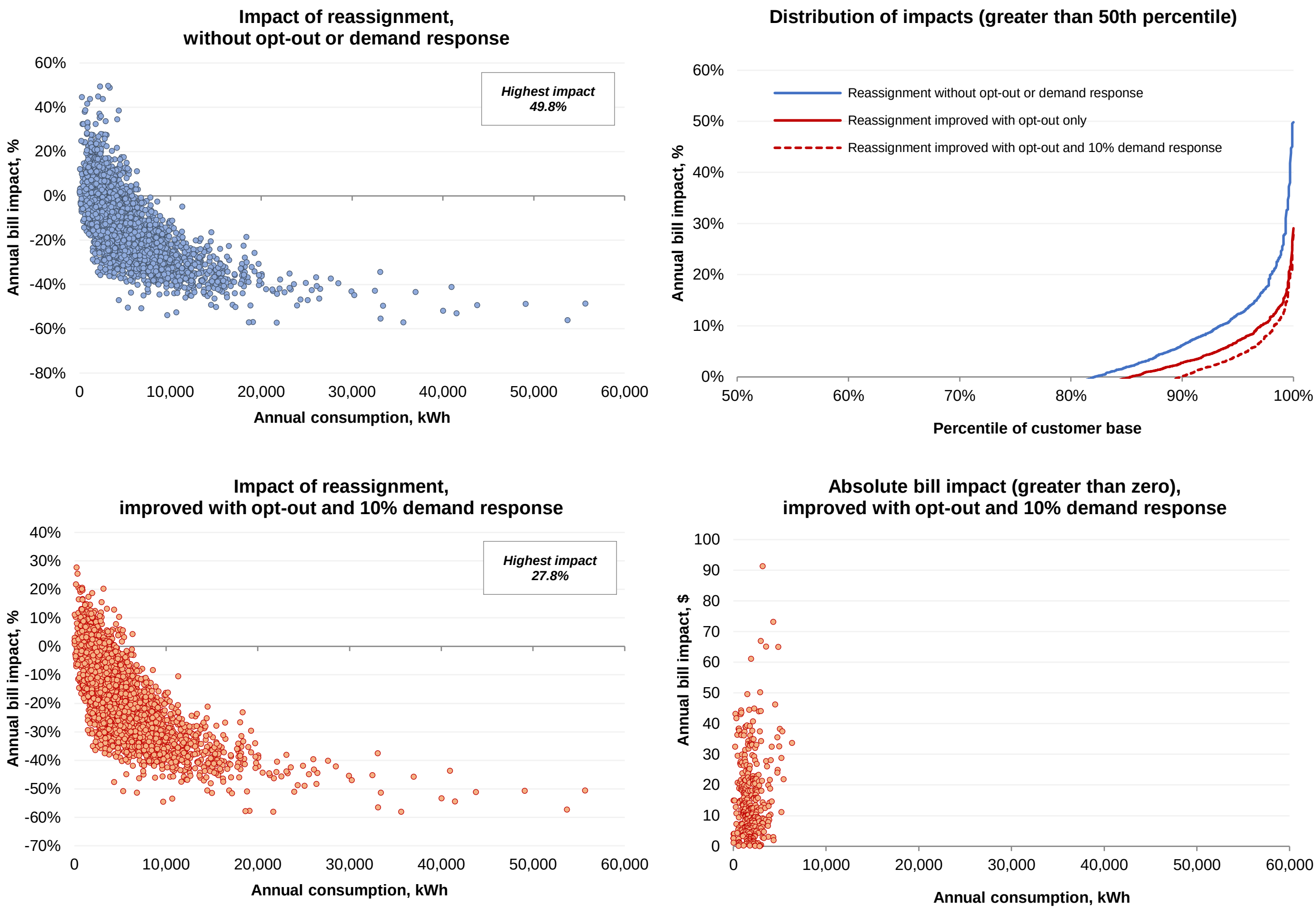






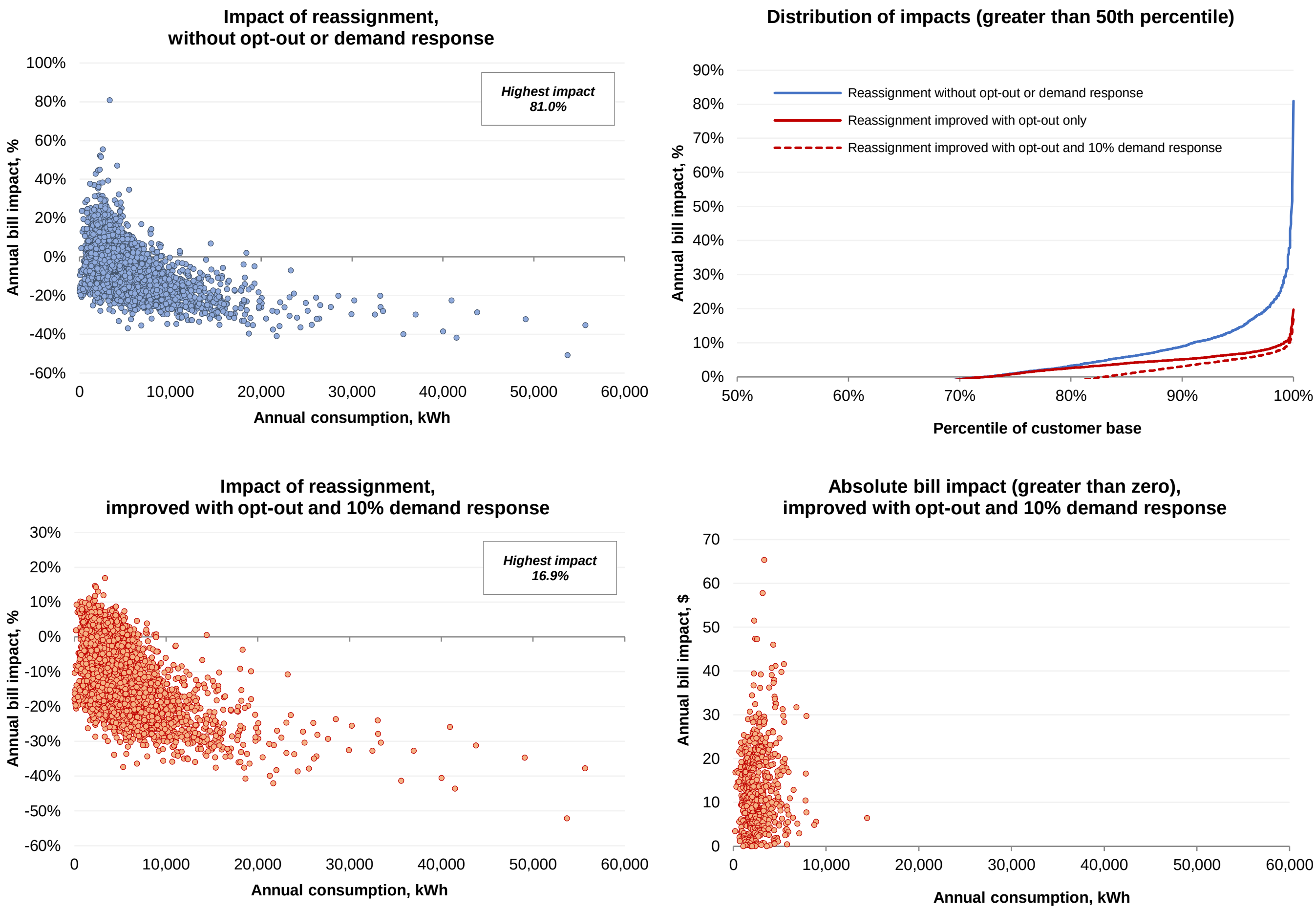
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	44.6%	0.0%	0.0%
Average annual bill impact, %	-0.2%	1.2%	N/A	N/A
Average annual bill impact, $	($3)	$5	N/A	N/A
Average annual consumption, kWh	5,189	3,941	N/A	N/A
Average maximum demand, kW	5.6	4.4	N/A	N/A
Average load factor, %	10.2%	9.9%	N/A	N/A

Figure A6.4. Opt-out of customers with smart meters from EA011 Transitional TOU to EA116 Demand on 1 July 2019



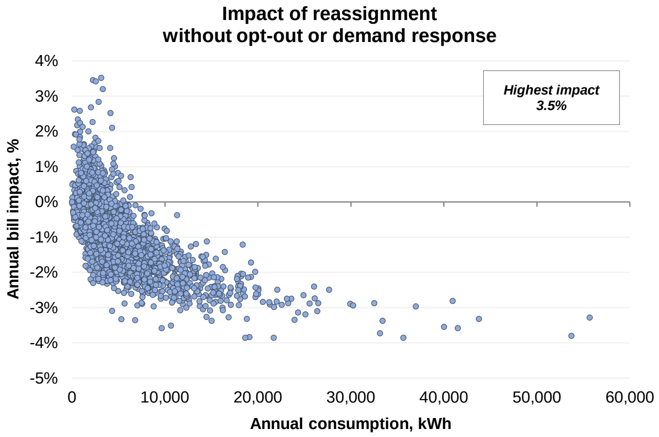
Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	10.1%	1.7%	0.2%
Average annual bill impact, %	-14.7%	5.4%	14.1%	22.1%
Average annual bill impact, $	($137)	$16	$38	$46
Average annual consumption, kWh	5,189	1,897	1,423	800
Average maximum demand, kW	5.6	4.6	4.8	4.1
Average load factor, %	10.2%	4.6%	3.3%	1.9%

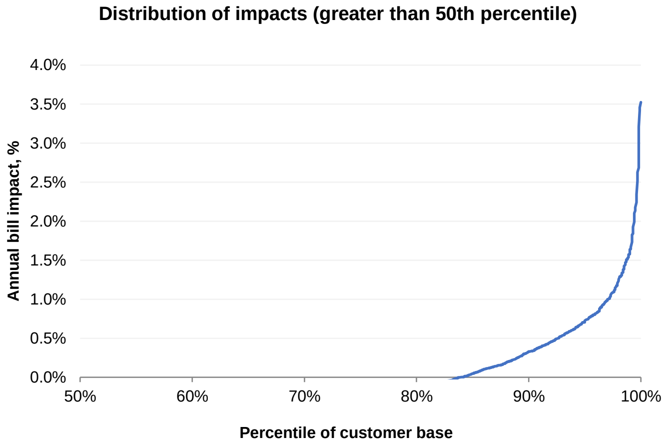
Figure A6.5. Opt-out of customers with smart meters from EA025 TOU to EA116 Demand on 1 July 2019

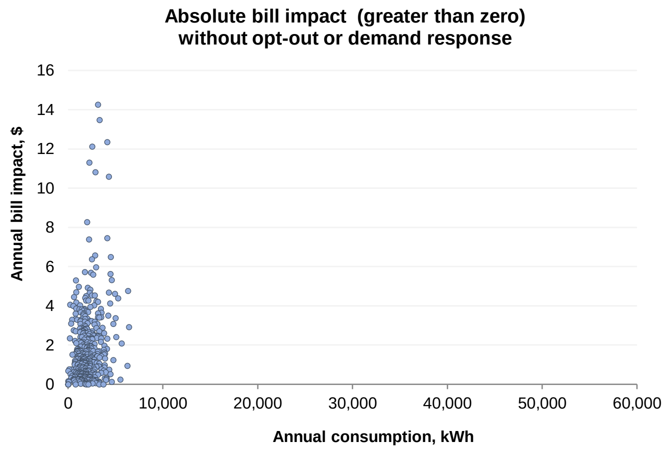


Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	17.1%	0.3%	0.0%
Average annual bill impact, %	-7.5%	3.9%	12.1%	N/A
Average annual bill impact, $	($65)	$14	$40	N/A
Average annual consumption, kWh	5,189	2,710	2,060	N/A
Average maximum demand, kW	5.6	5.3	8.6	N/A
Average load factor, %	10.2%	5.8%	2.9%	N/A

Figure A6.6. Reassignment of customers with accumulation meters from EA010 Non-TOU/EA011 transitional TOU to EA111 Demand (introductory) on meter replacement due to failure in 2019/20

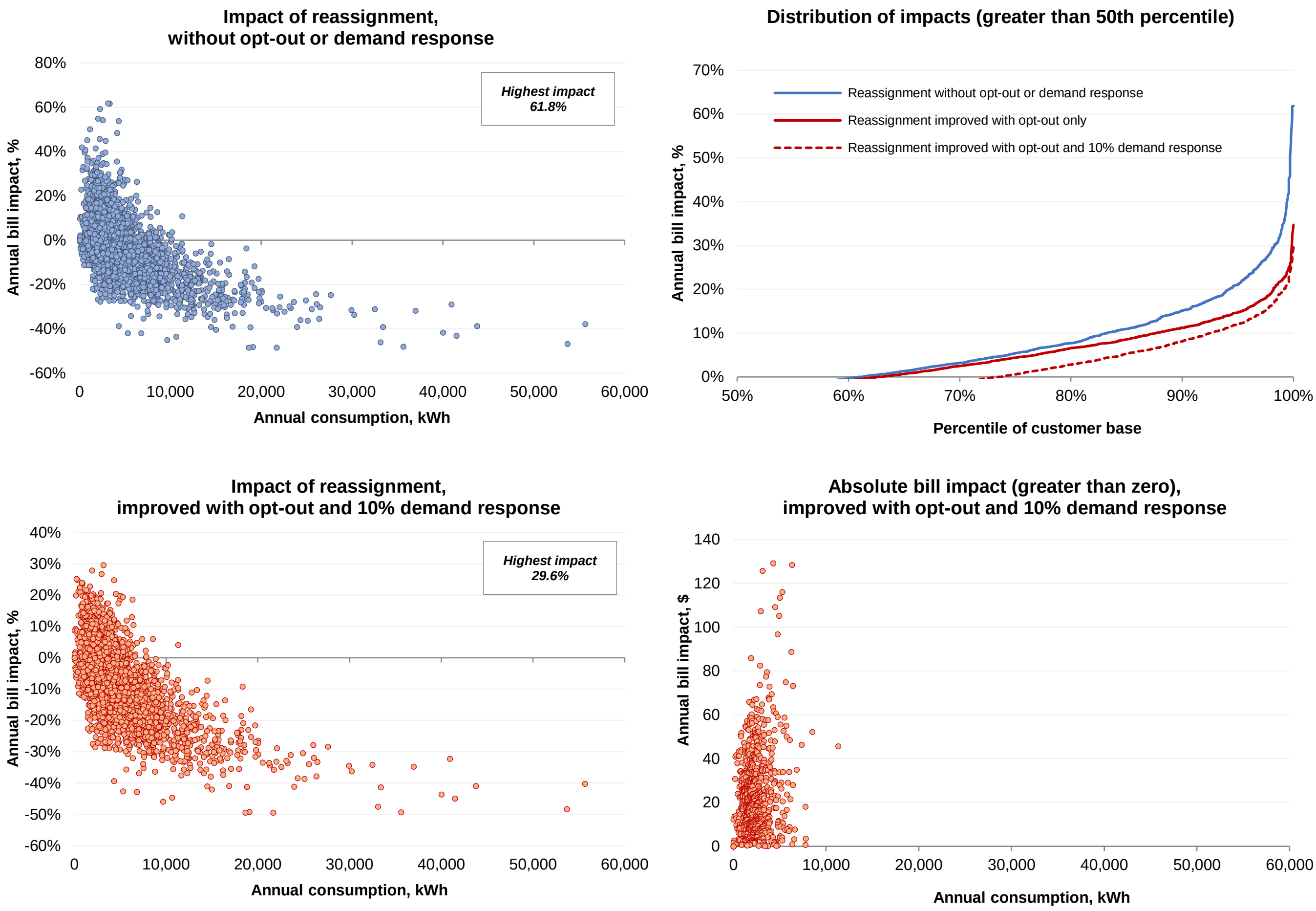






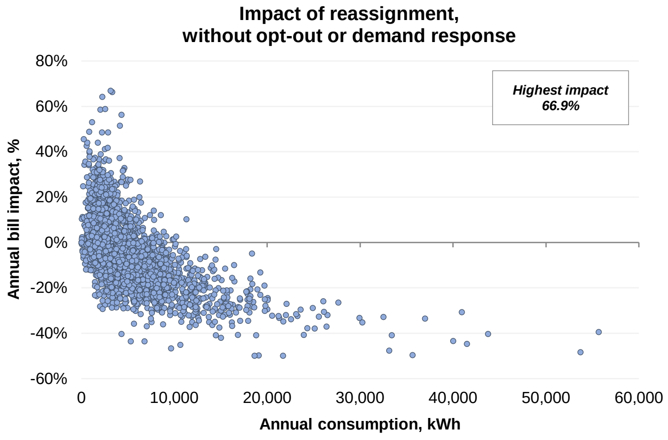
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	16.0%	0.0%	0.0%
Average annual bill impact, %	-0.9%	0.6%	N/A	N/A
Average annual bill impact, $	($8)	$2	N/A	N/A
Average annual consumption, kWh	5,117	2,096	N/A	N/A
Average maximum demand, kW	5.4	4.7	N/A	N/A
Average load factor, %	10.3%	5.1%	N/A	N/A

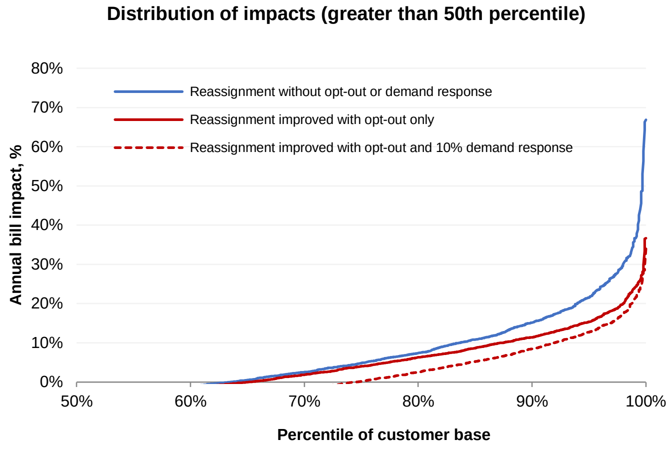
Figure A6.7. Reassignment of customers from EA111 Demand (introductory) to EA116 Demand after 12 months (in 2020/21)

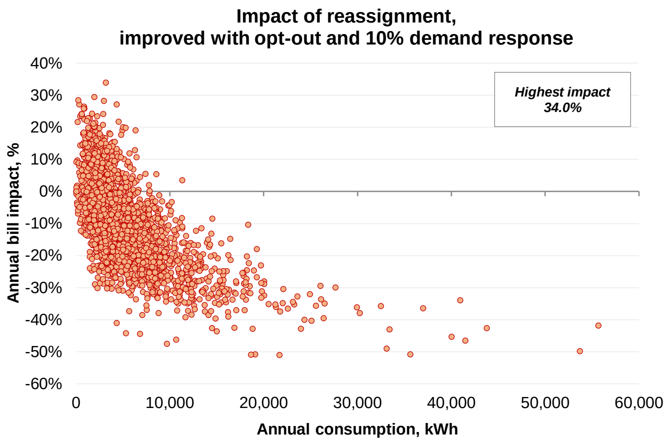


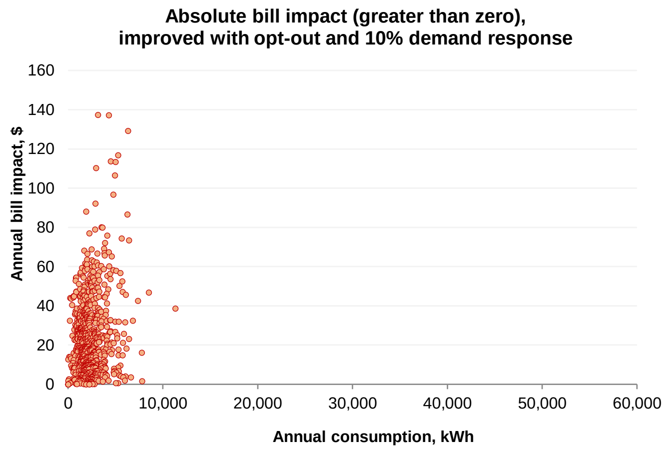
Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	26.3%	7.5%	0.8%
Average annual bill impact, %	-4.7%	7.3%	14.5%	23.1%
Average annual bill impact, $	($57)	$25	$47	$66
Average annual consumption, kWh	5,117	2,482	2,089	1,593
Average maximum demand, kW	5.4	4.8	5.0	5.5
Average load factor, %	10.3%	5.9%	4.7%	3.2%

Figure A6.8. Reassignment of customers from EA010 Non-TOU/EA011 transitional TOU to EA116 Demand after meter upgrade to smart meter by customer choice (in 2019/20)



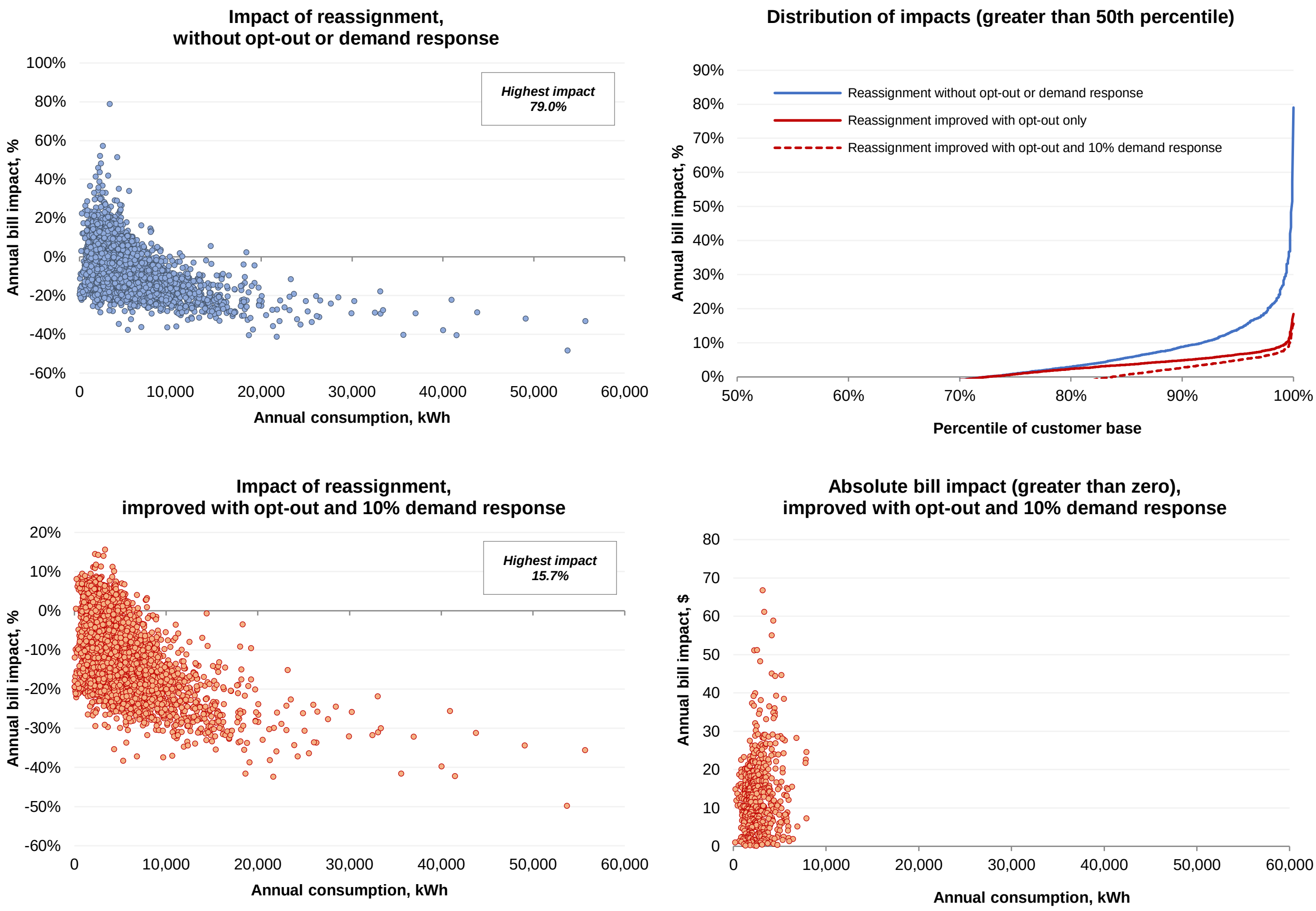






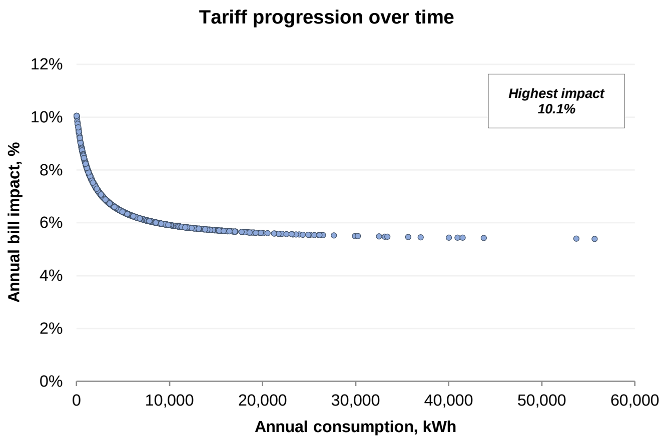
Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	25.4%	8.1%	1.2%
Average annual bill impact, %	-5.5%	7.8%	15.1%	23.7%
Average annual bill impact, $	($64)	$26	$47	$67
Average annual consumption, kWh	5,117	2,439	2,115	1,721
Average maximum demand, kW	5.4	4.8	5.1	5.6
Average load factor, %	10.3%	5.8%	4.7%	3.3%

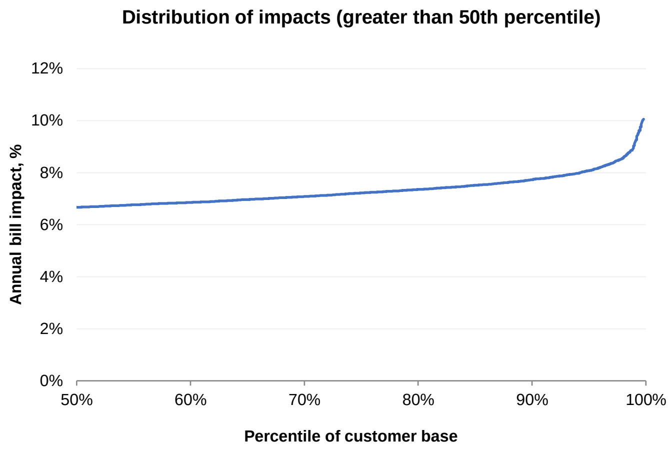
Figure A6.9. Opt-out of customers from EA025 TOU to EA116 Demand after meter upgrade from interval to smart meter (in 2019/20)

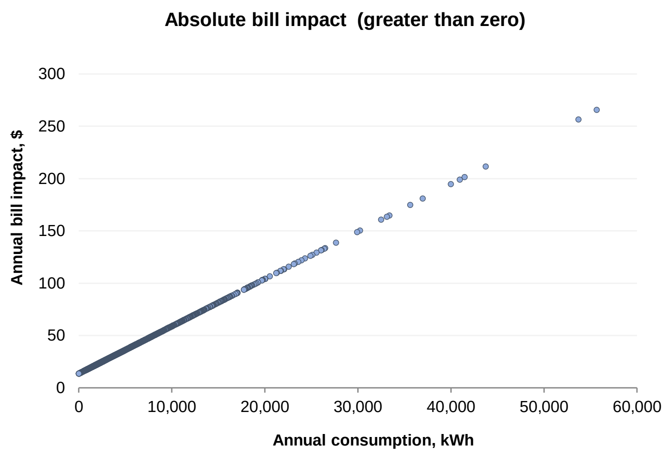


Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	16.2%	0.3%	0.0%
Average annual bill impact, %	-7.4%	3.7%	12.4%	N/A
Average annual bill impact, $	($62)	$14	$50	N/A
Average annual consumption, kWh	5,189	2,724	2,839	N/A
Average maximum demand, kW	5.6	5.5	10.7	N/A
Average load factor, %	10.2%	5.7%	3.2%	N/A

Figure A6.10. Tariff progression over time: EA010 Non-TOU/EA011 transitional TOU from 2019/20 to 2023/24

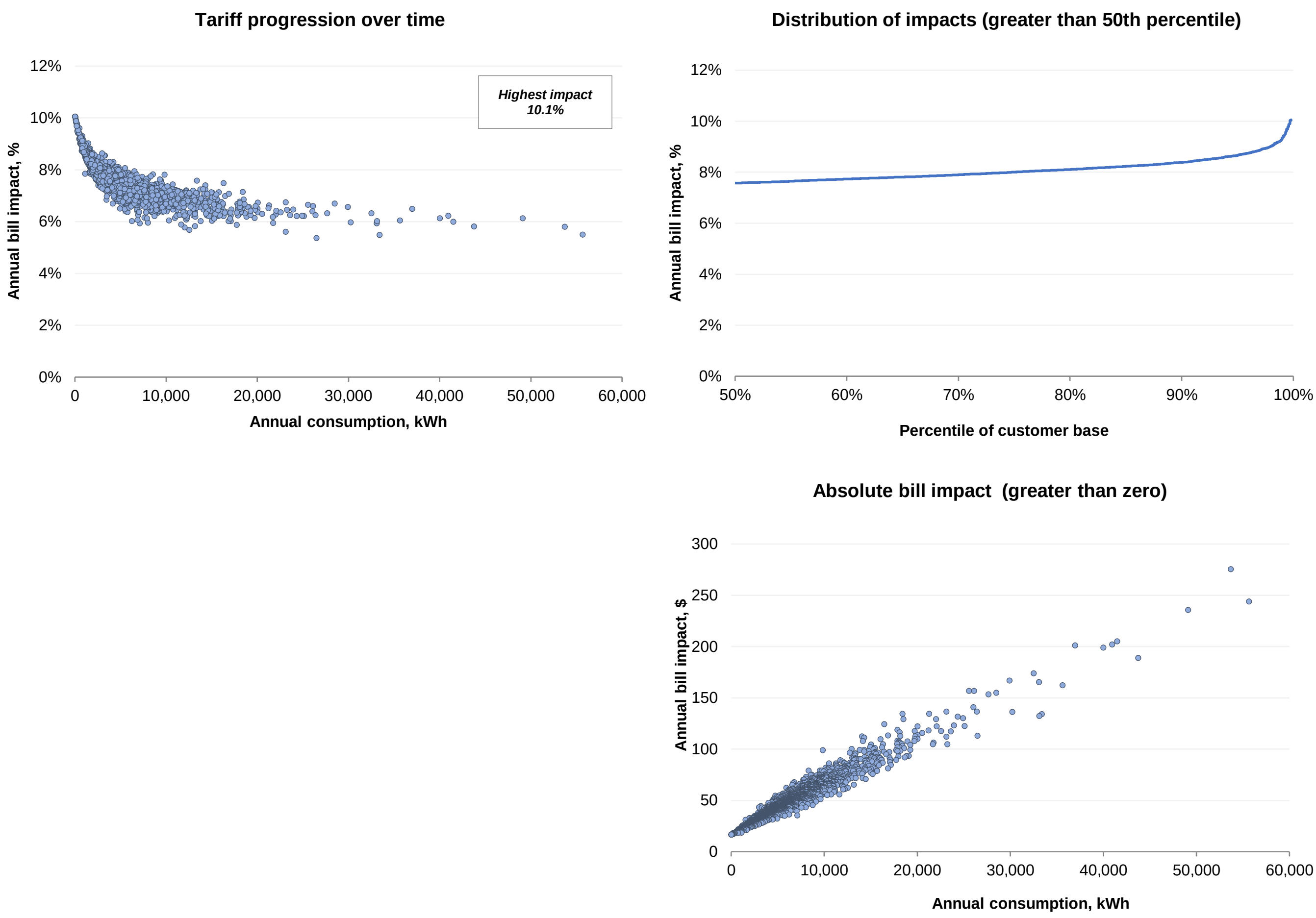






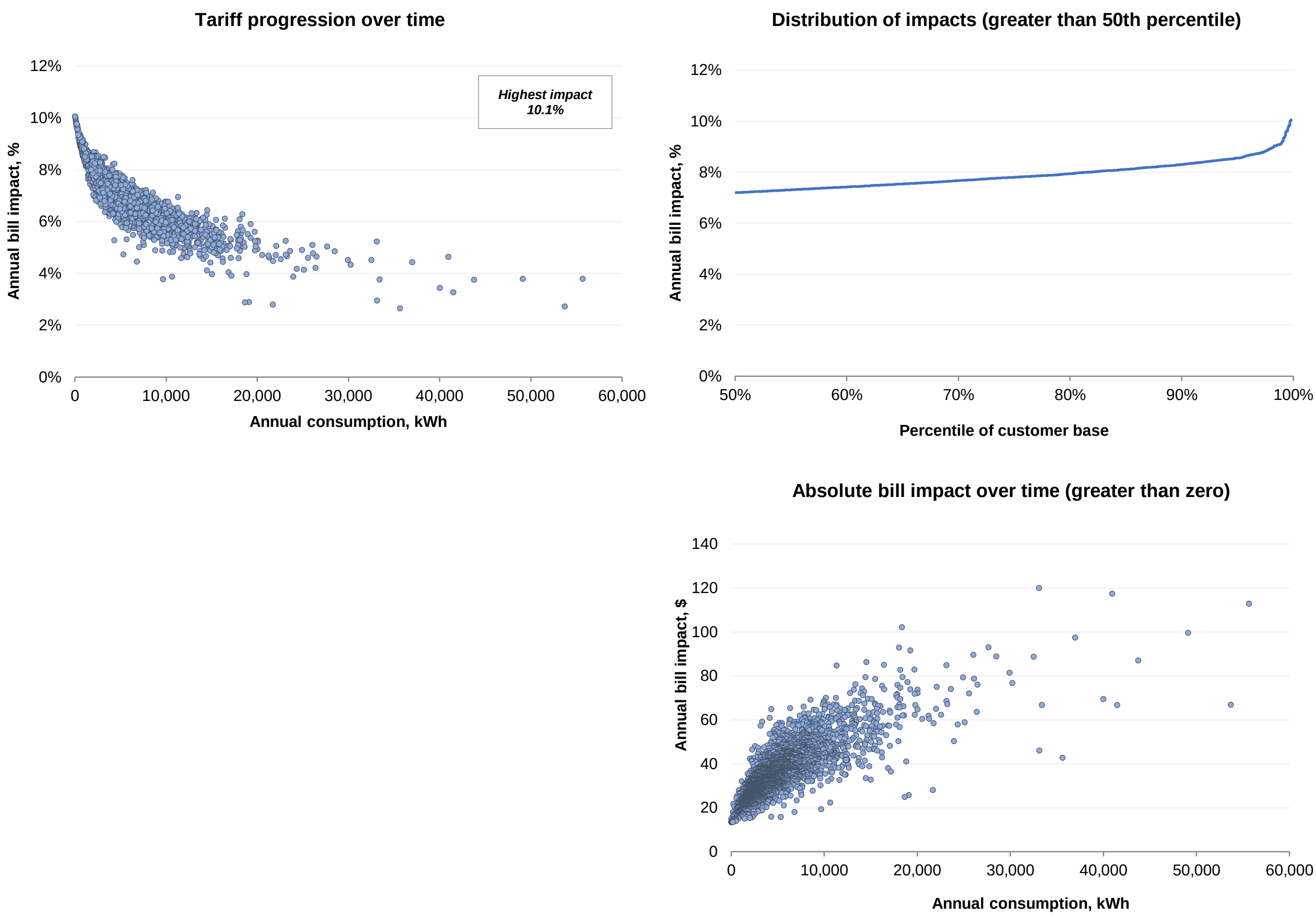
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.3%	0.0%
Average cumulative bill impact, %	6.8%	6.8%	10.1%	N/A
Average cumulative bill impact, $	$37	$37	$14	N/A
Average annual consumption, kWh	5,117	5,117	2	N/A
Average maximum demand, kW	5.4	5.4	0.2	N/A
Average load factor, %	10.3%	10.3%	0.0%	N/A

Figure A6.11. Tariff progression over time: EA025 TOU from 2019/20 to 2023/24



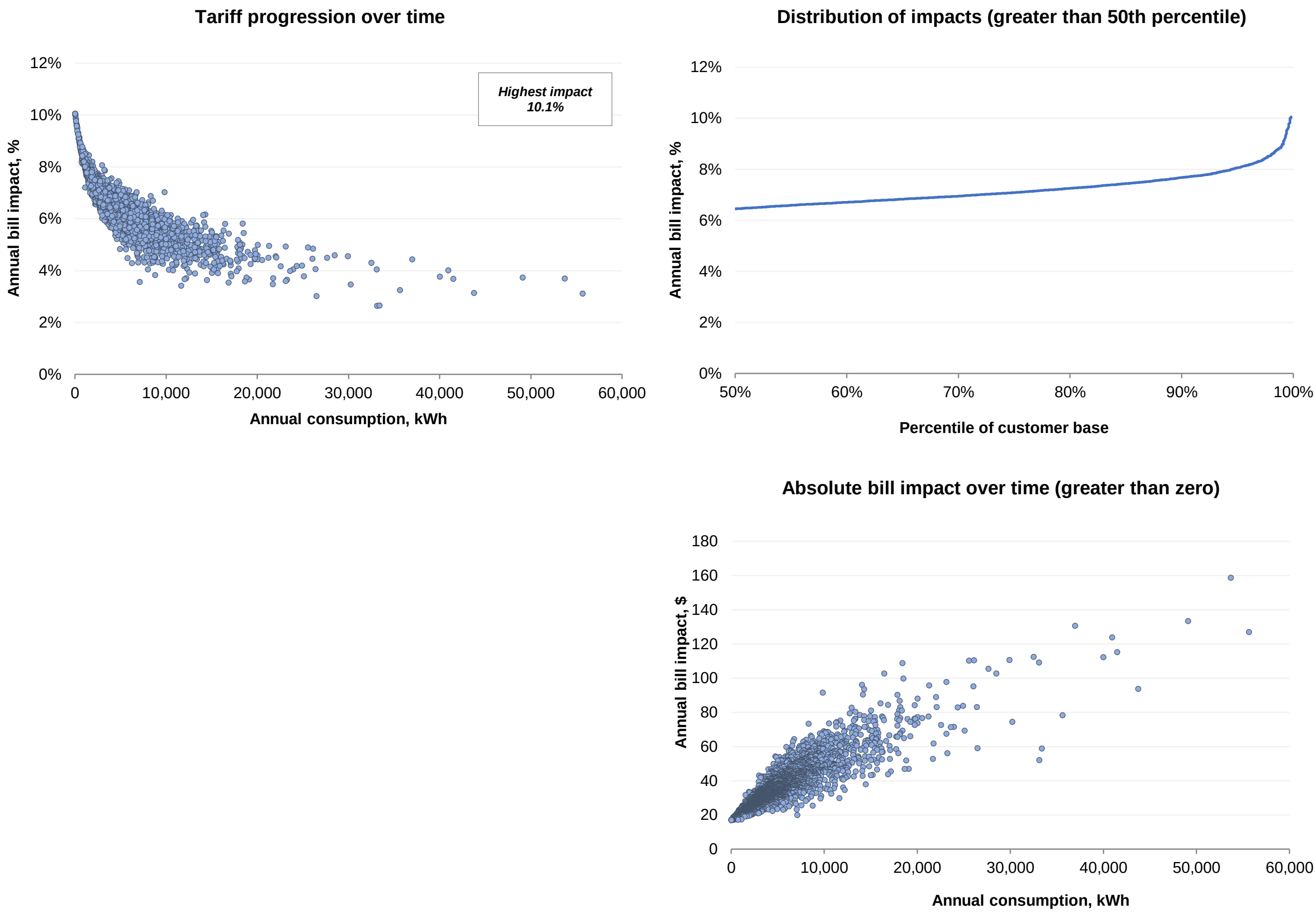
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.3%	0.0%
Average cumulative bill impact, %	7.6%	7.6%	10.0%	N/A
Average cumulative bill impact, $	$43	$43	$17	N/A
Average annual consumption, kWh	5,189	5,189	6	N/A
Average maximum demand, kW	5.6	5.6	0.2	N/A
Average load factor, %	10.2%	10.2%	0.1%	N/A

Figure A6.12. Tariff progression over time: EA116 Demand from 2019/20 to 2023/24



Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.3%	0.0%
Average cumulative bill impact, %	7.1%	7.1%	10.0%	N/A
Average cumulative bill impact, $	$36	$36	$14	N/A
Average annual consumption, kWh	5,189	5,189	6	N/A
Average maximum demand, kW	5.6	5.6	0.2	N/A
Average load factor, %	10.2%	10.2%	0.1%	N/A

Figure A6.13. Tariff progression over time: EA115 TOU demand from 2019/20 to 2023/24



Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.3%	0.0%
Average annual bill impact, %	6.4%	6.4%	10.0%	N/A
Average annual bill impact, $	$35	$35	$17	N/A
Average annual consumption, kWh	5,189	5,189	6	N/A
Average maximum demand, kW	5.6	5.6	0.2	N/A
Average load factor, %	10.2%	10.2%	0.1%	N/A

Small business customer impacts

Based on Figure 2.4 in Section 2 of the Tariff Structure Statement showing the assignment of small business customers from 1 July 2019, the following figures show the impact on small business customers moving from their current tariff to a new tariff from 1 July 2019 and impacts at the end of the regulatory period in 2023/24.

Box A6.2 is a key to the set of small business customer impact figures including:

- Figures A6.14 to A6.18: the impact on customers on each of the tariffs in 2018/19 from 1 July 2019
- Figures A6.19 and A6.20: the impact on customers on flat tariffs being assigned to a new demand (introductory) tariff due to meter failure after 1 July 2019, and the impact of being reassigned to the default demand tariff after 12 months
- Figure A6.21: the impact on customers being assigned to a new demand tariff due to change from a flat tariff to a smart meter by customer initiated action after 1 July 2019
- Figure A6.22: the impact on TOU customers opting-in to a demand tariff due to change for any reason from an interval meter to a smart meter after 1 July 2019
- Figures A6.23 and A6.24: the impact on customers on the continuing non-demand tariffs of tariff price progression from 2019/20 to the end of the regulatory period in 2023/24
- Figures A6.25 and A6.26: the impact on customers on the two new demand tariffs of tariff price progression from 2019/20 to the end of the regulatory period in 2023/24.

Box A6.2. Key to small business customer impact figures

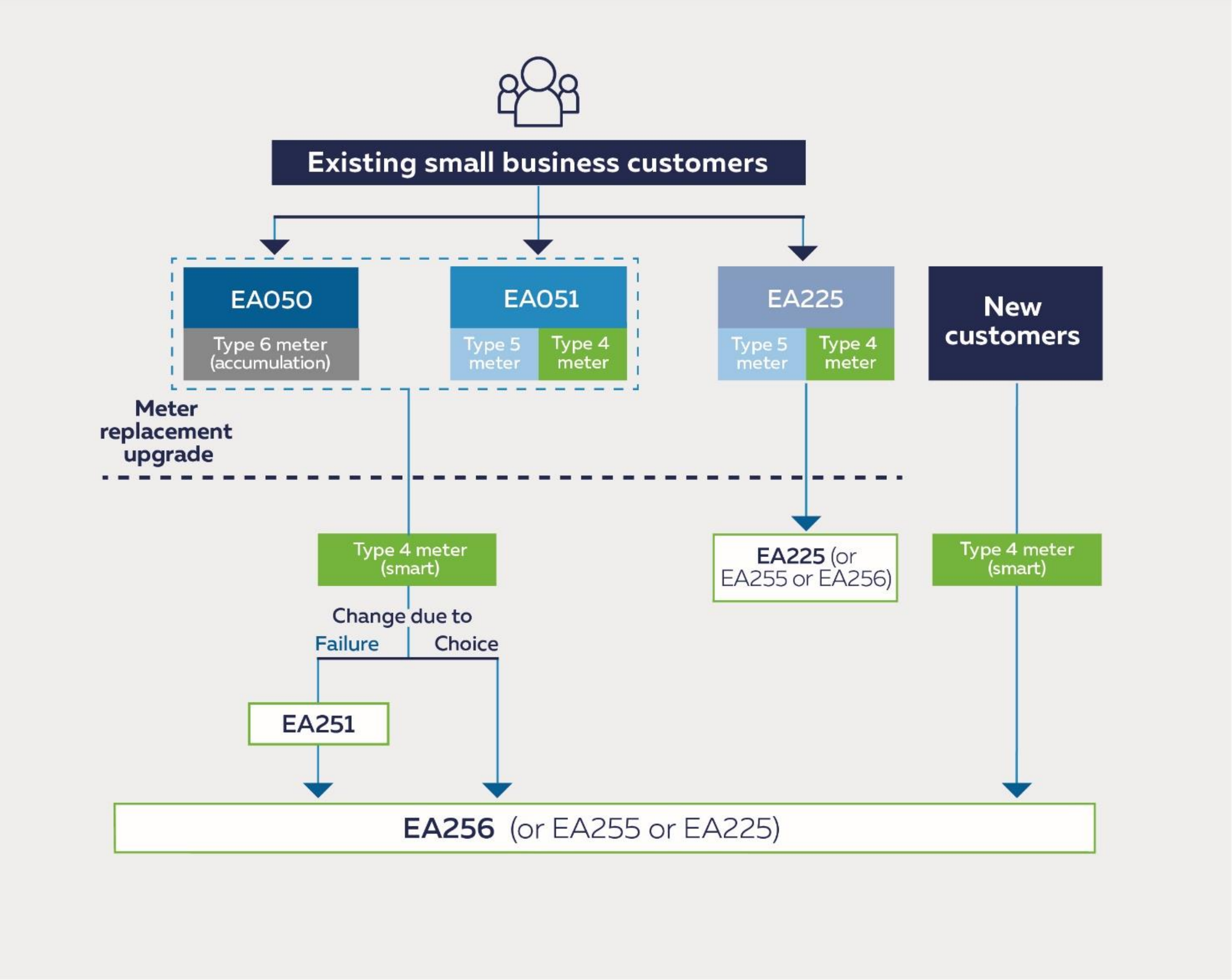
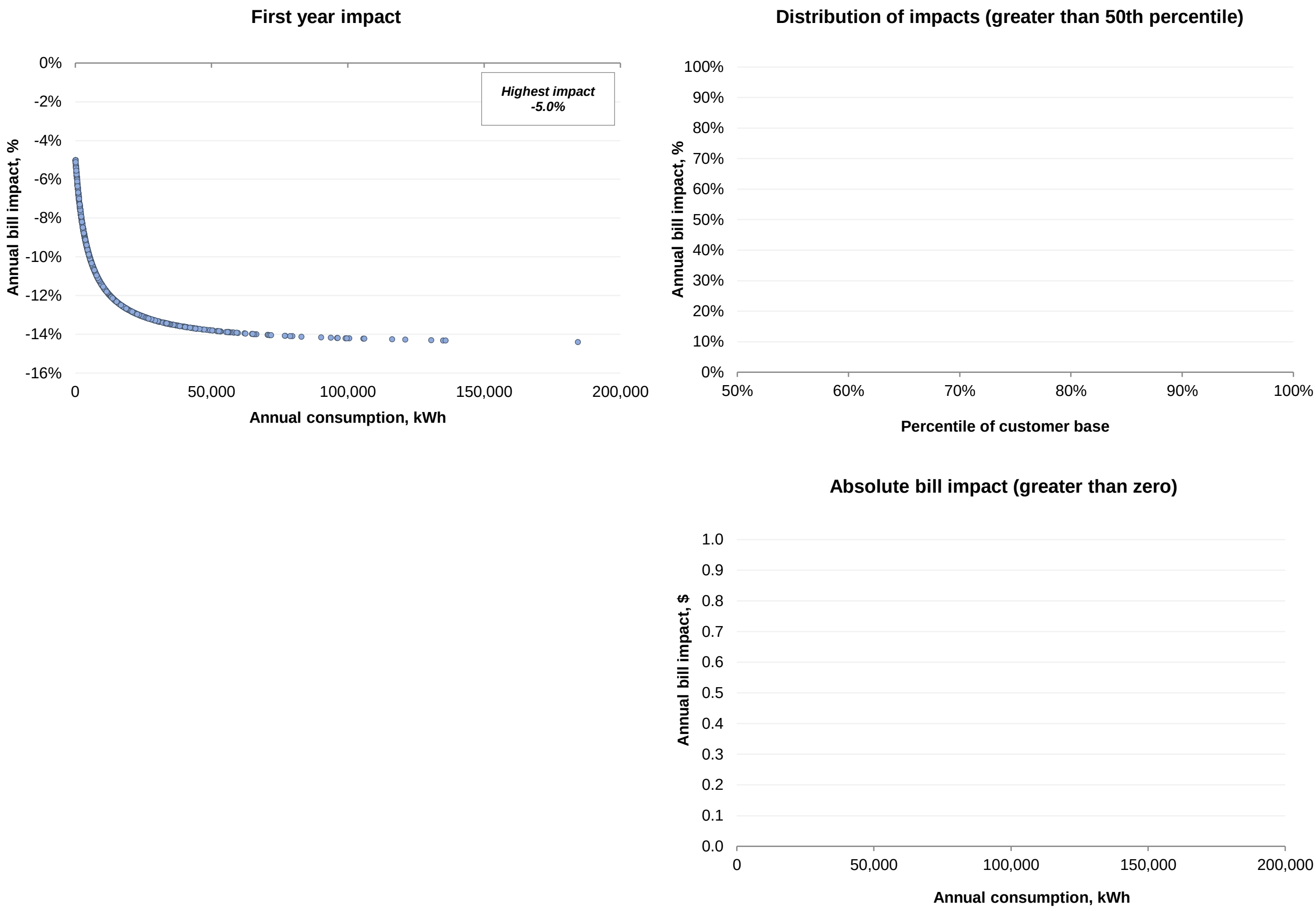
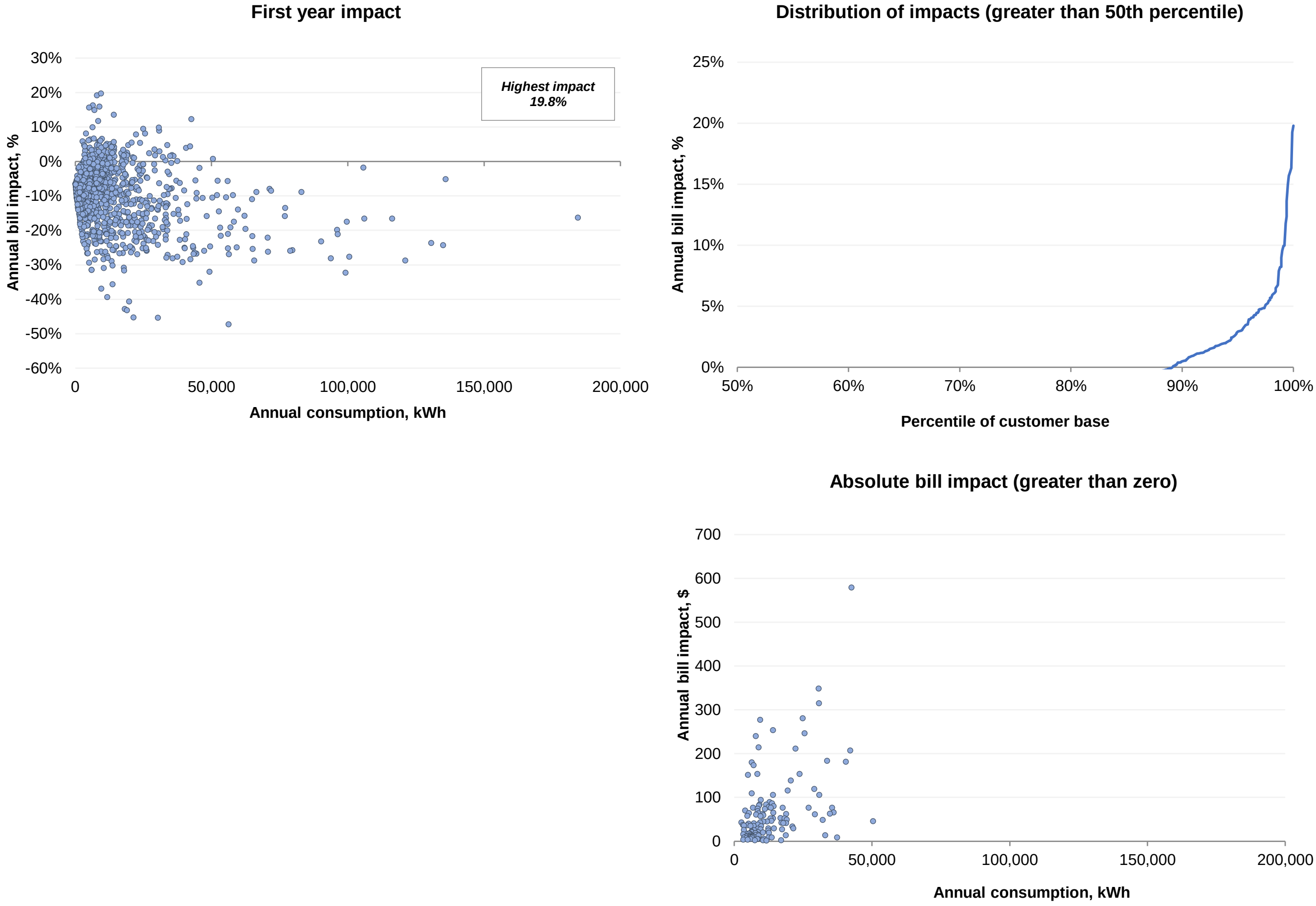


Figure A6.14. First year impact: EA050 Non-TOU/EA051 transitional TOU from 2018/19 to 2019/20



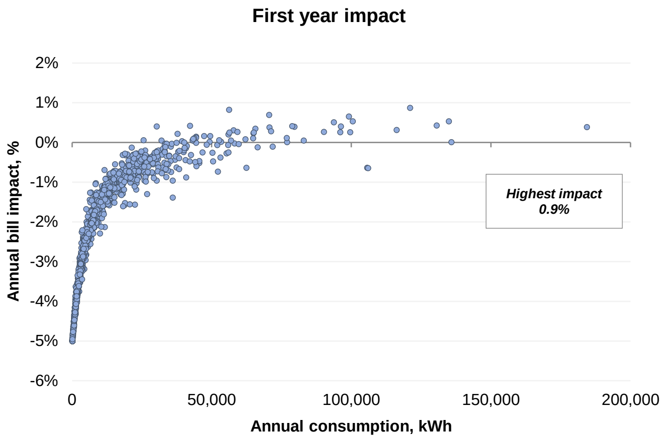
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	0.0%	0.0%	0.0%
Average annual bill impact, %	-10.4%	N/A	N/A	N/A
Average annual bill impact, $	($214)	N/A	N/A	N/A
Average annual consumption, kWh	13,105	N/A	N/A	N/A
Average maximum demand, kW	8.0	N/A	N/A	N/A
Average load factor, %	19.7%	N/A	N/A	N/A

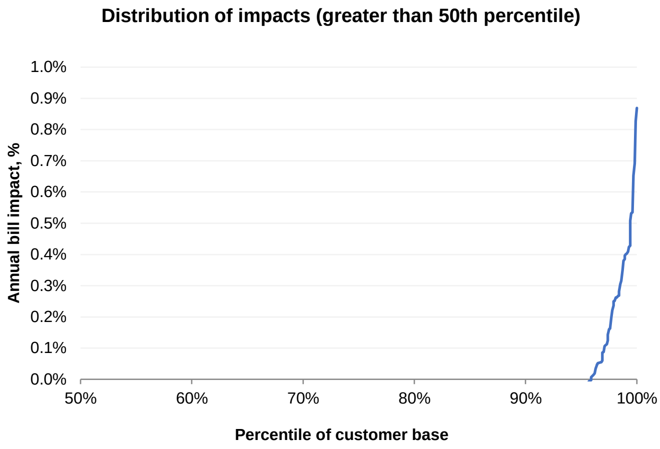
Figure A6.15. Opt-out of customers with interval meters from EA051 Transitional TOU to EA225 TOU on 1 July 2019

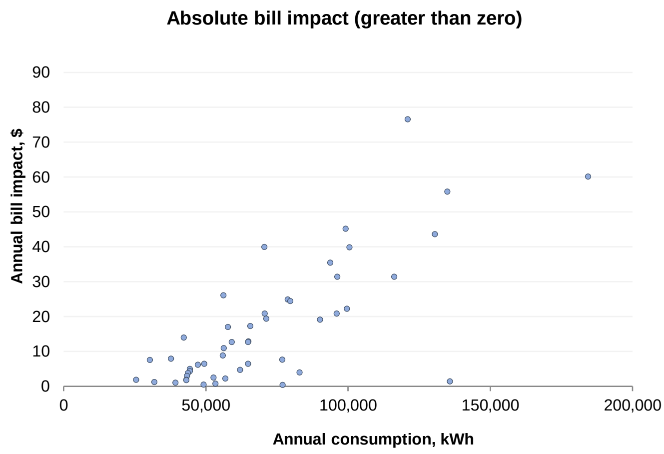


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	10.8%	0.8%	0.0%
Average annual bill impact, %	-9.6%	3.8%	15.5%	N/A
Average annual bill impact, $	($212)	$69	$247	N/A
Average annual consumption, kWh	13,105	13,422	12,106	N/A
Average maximum demand, kW	8.0	12.4	19.9	N/A
Average load factor, %	19.7%	13.7%	9.0%	N/A

Figure A6.16. First year impact: EA225 TOU from 2018/19 to 2019/20

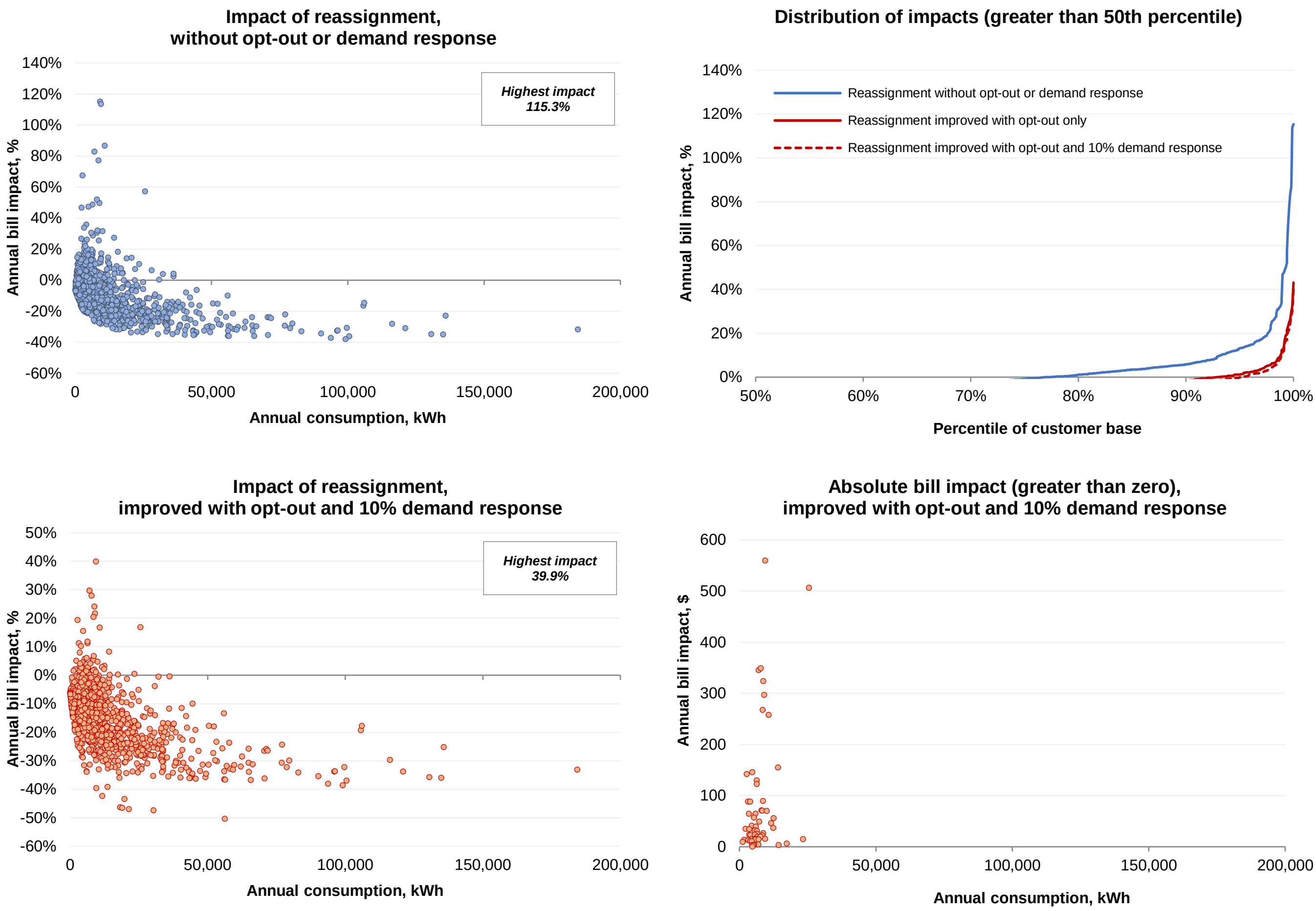






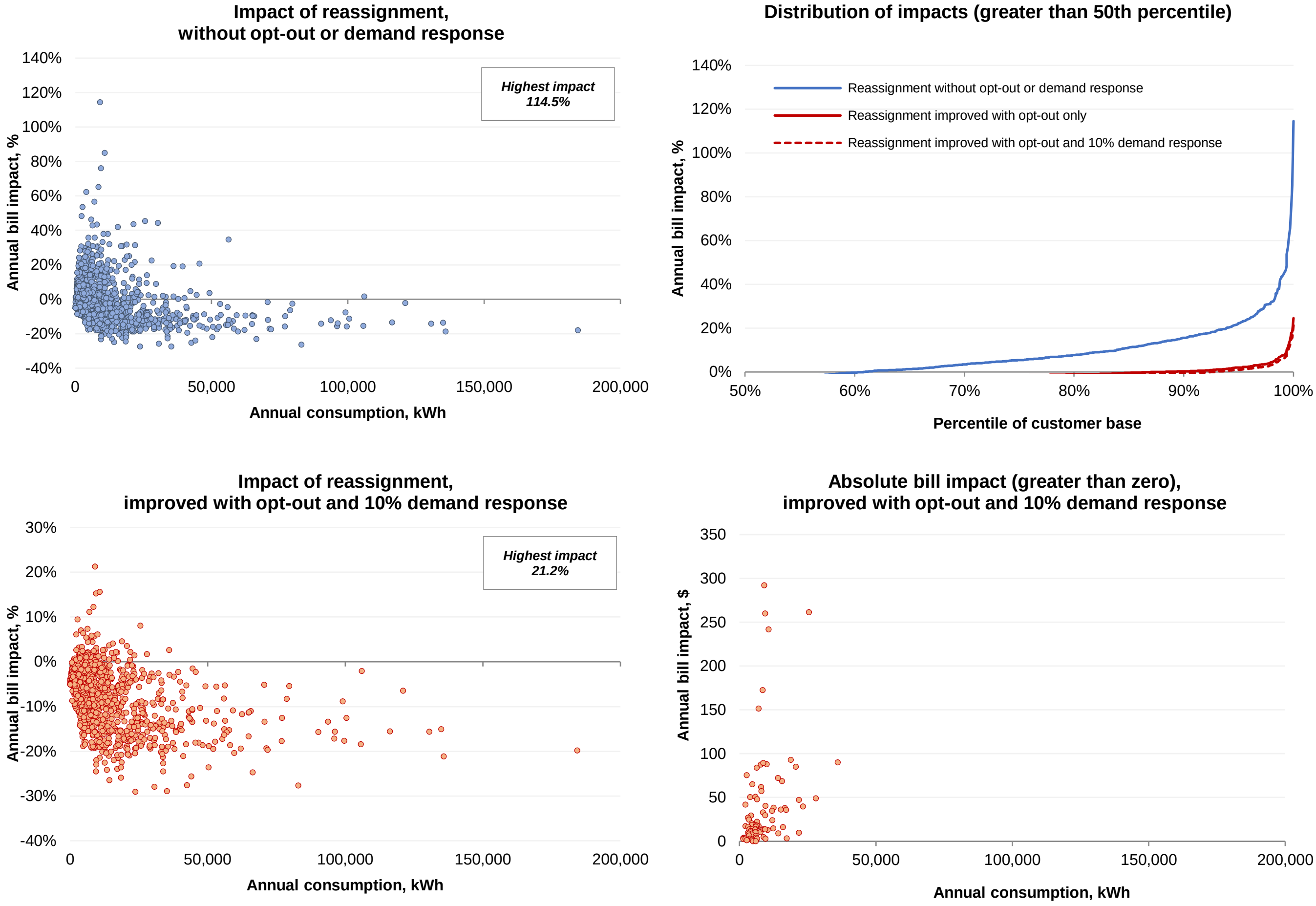
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	4.1%	0.0%	0.0%
Average annual bill impact, %	-2.1%	0.3%	N/A	N/A
Average annual bill impact, $	($19)	$17	N/A	N/A
Average annual consumption, kWh	13,105	71,198	N/A	N/A
Average maximum demand, kW	8.0	23.1	N/A	N/A
Average load factor, %	19.7%	40.5%	N/A	N/A

Figure A6.17. Opt-out of customers with smart meters from EA051 Transitional TOU to EA256 Demand on 1 July 2019



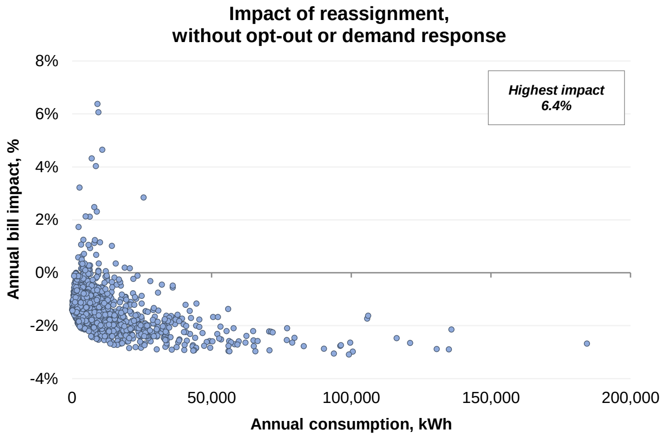
Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	4.8%	1.2%	0.5%
Average annual bill impact, %	-13.0%	6.9%	19.8%	27.3%
Average annual bill impact, $	($323)	$87	$259	$357
Average annual consumption, kWh	13,105	7,349	8,086	8,374
Average maximum demand, kW	8.0	15.4	28.7	31.3
Average load factor, %	19.7%	6.4%	3.7%	3.3%

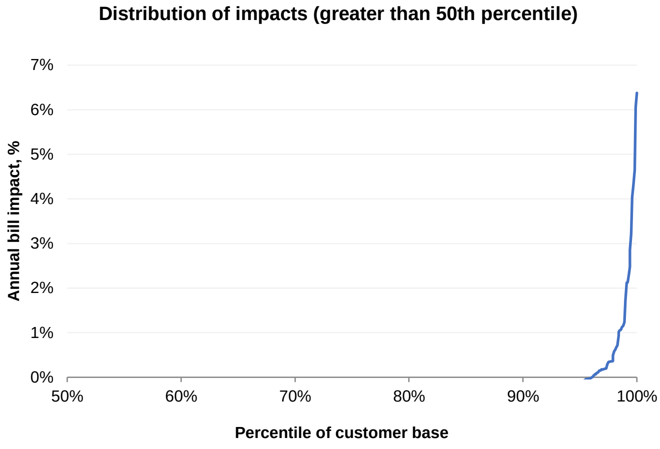
Figure A6.18. Reassignment of customers with smart meters from EA225 TOU to EA256 Demand on 1 July 2019

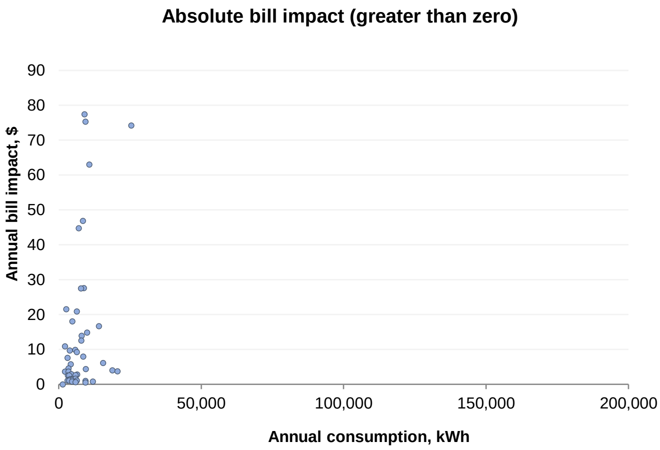


Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	7.3%	0.4%	0.1%
Average annual bill impact, %	-5.8%	3.0%	15.1%	21.2%
Average annual bill impact, $	($130)	$41	$224	$292
Average annual consumption, kWh	13,105	8,648	8,880	9,016
Average maximum demand, kW	8.0	16.5	40.8	40.0
Average load factor, %	19.7%	6.4%	2.7%	2.6%

Figure A6.19. Reassignment of customers with accumulation meters from EA050 Non-TOU/EA051 transitional TOU to EA251 Demand (introductory) on meter replacement due to failure in 2019/20

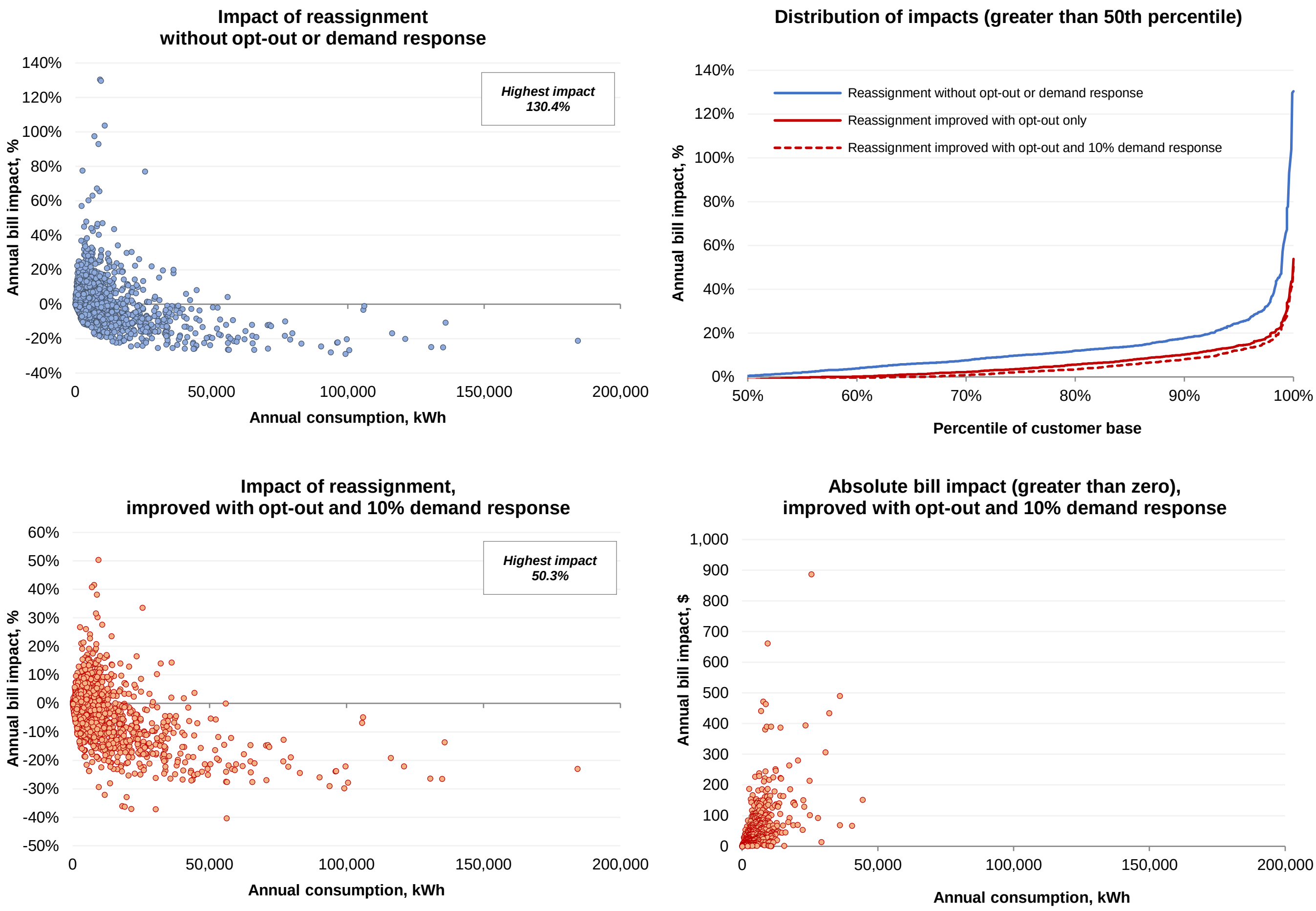






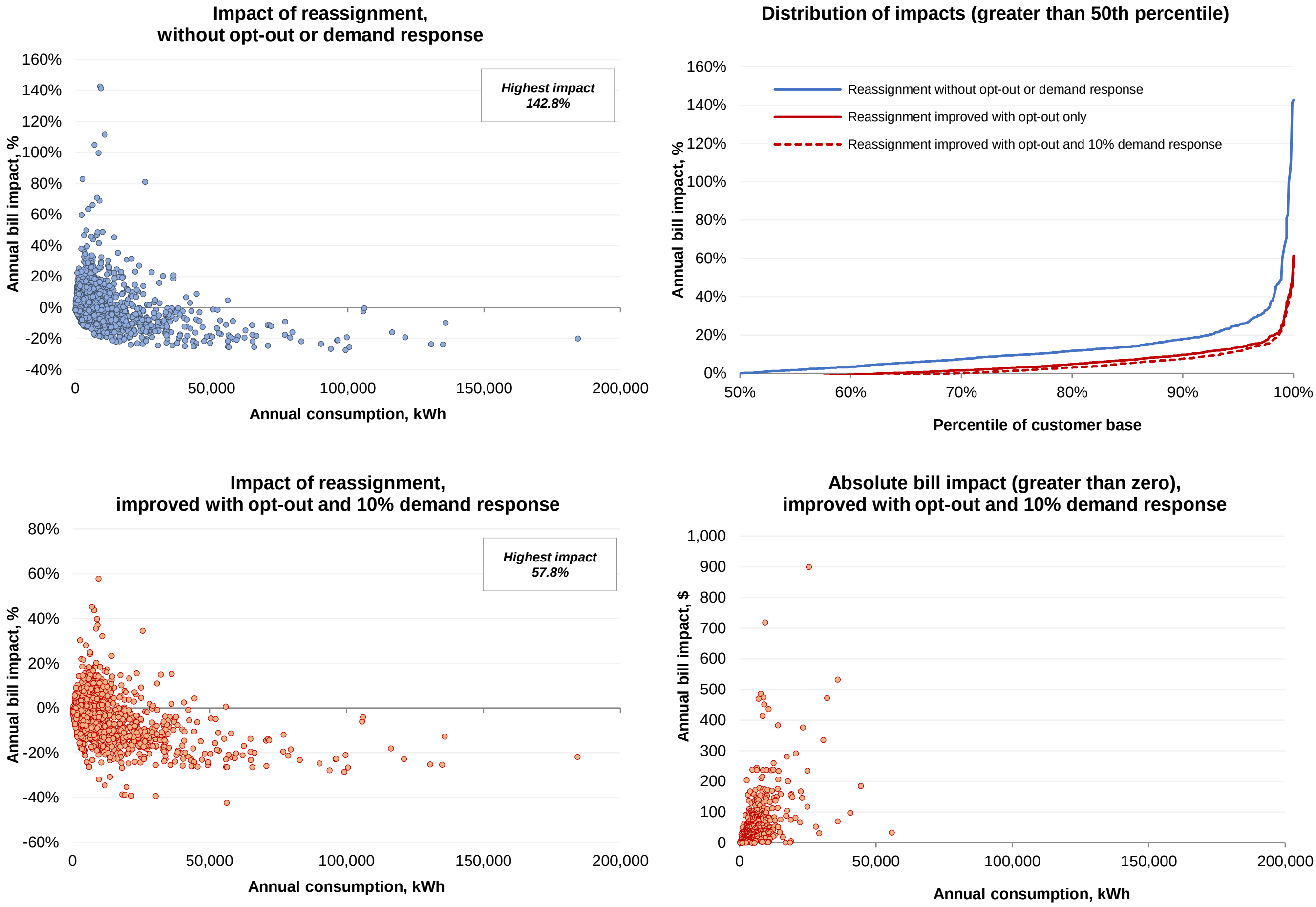
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	3.9%	0.0%	0.0%
Average annual bill impact, %	-1.4%	1.2%	N/A	N/A
Average annual bill impact, $	($27)	$14	N/A	N/A
Average annual consumption, kWh	13,105	7,324	N/A	N/A
Average maximum demand, kW	8.0	17.4	N/A	N/A
Average load factor, %	19.7%	5.4%	N/A	N/A

Figure A6.20. Reassignment of customers from EA251 Demand (introductory) to EA256 Demand after 12 months (in 2020/21)



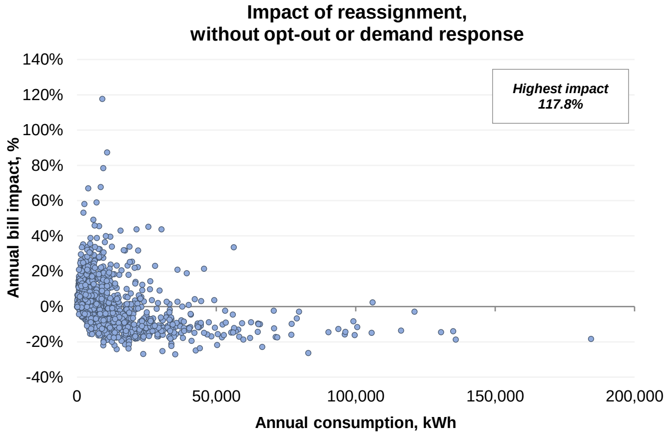
Summary results - improved with opt-out and 10% demand response	**All**	**Impact > 0%**	**Impact > 10%**	**Impact > 20%**
Share in sample	100.0%	33.9%	6.9%	1.3%
Average annual bill impact, %	-2.2%	6.6%	16.7%	30.0%
Average annual bill impact, $	($99)	$74	$201	$370
Average annual consumption, kWh	13,105	6,908	8,725	8,490
Average maximum demand, kW	8.0	8.7	14.8	28.0
Average load factor, %	19.7%	9.0%	7.5%	3.9%

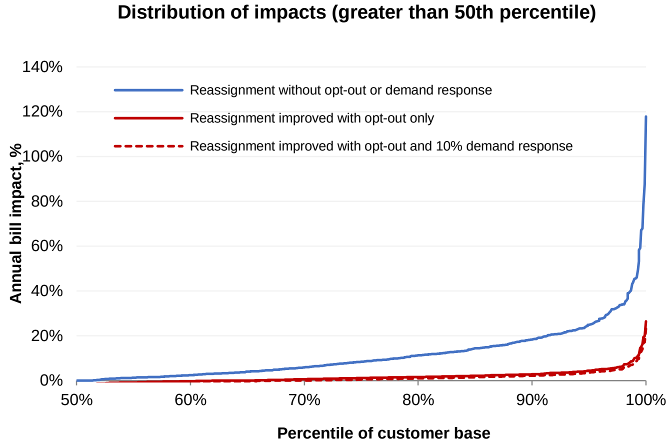
Figure A6.21. Reassignment of customers from EA050 Non-TOU/EA051 transitional TOU to EA256 Demand after meter upgrade to smart meter by customer choice (in 2019/20)

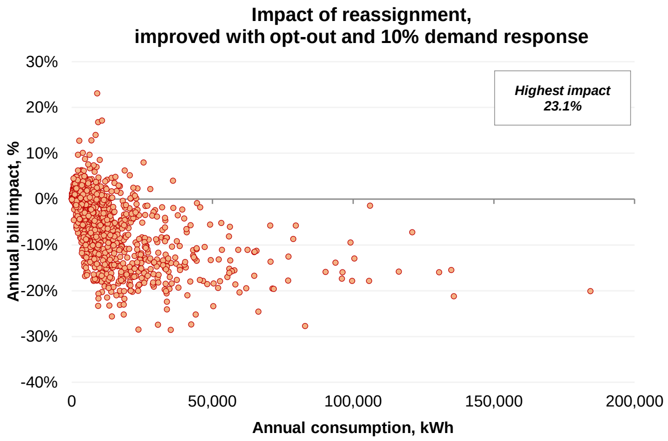


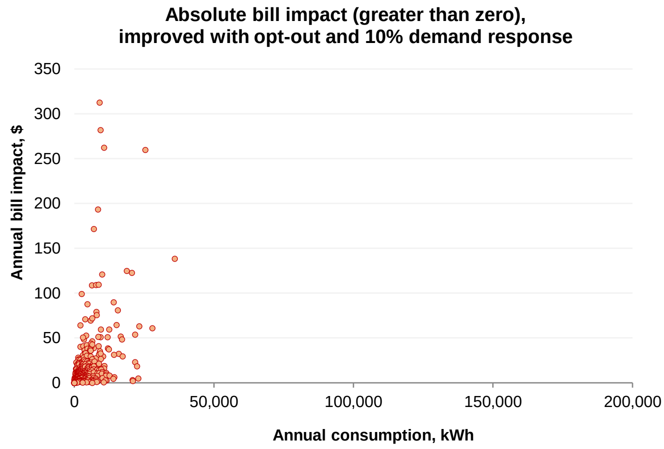
Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	30.6%	6.6%	1.3%
Average annual bill impact, %	-2.9%	6.9%	17.3%	32.6%
Average annual bill impact, $	($109)	$80	$211	$389
Average annual consumption, kWh	13,105	7,673	8,987	8,490
Average maximum demand, kW	8.0	9.4	15.2	28.0
Average load factor, %	19.7%	9.5%	7.4%	3.9%

Figure A6.22. Opt-out of customers from EA225 TOU to EA256 Demand after meter upgrade from interval to smart meter (in 2019/20)



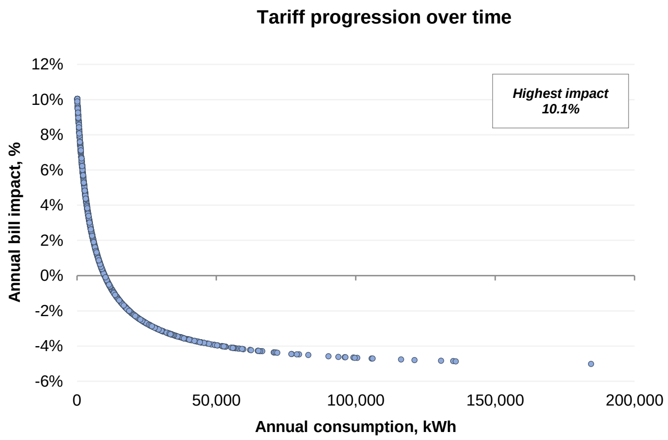


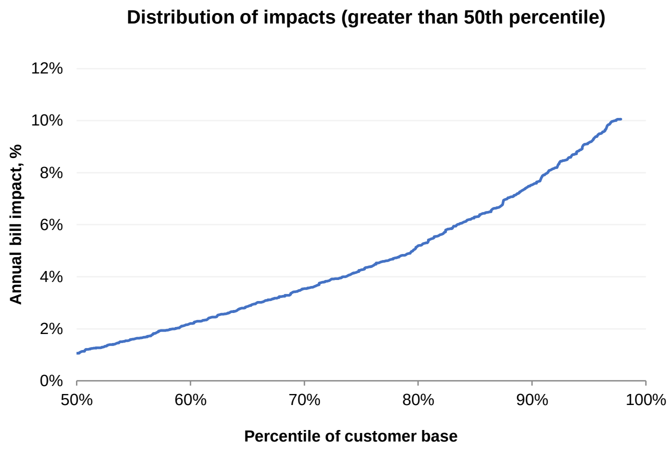


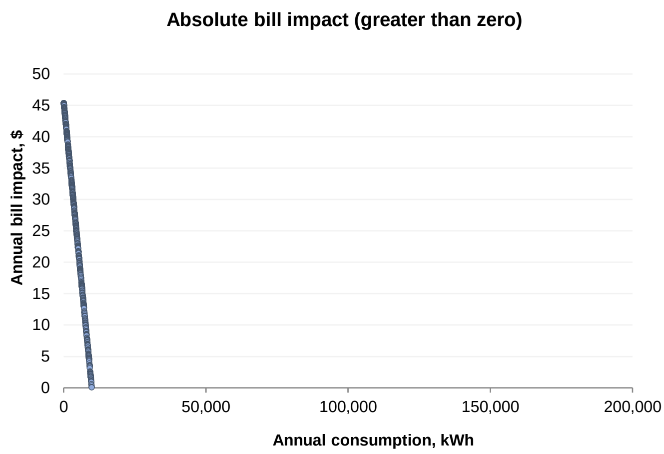


Summary results - improved with opt-out and 10% demand response	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	30.3%	0.6%	0.1%
Average annual bill impact, %	-3.7%	2.2%	15.2%	23.1%
Average annual bill impact, $	($111)	$22	$199	$313
Average annual consumption, kWh	13,105	4,922	7,269	9,016
Average maximum demand, kW	8.0	8.0	34.1	40.0
Average load factor, %	19.7%	7.0%	2.7%	2.6%

Figure A6.23. Tariff progression over time: EA050 Non-TOU/EA051 transitional TOU from 2019/20 to 2023/24

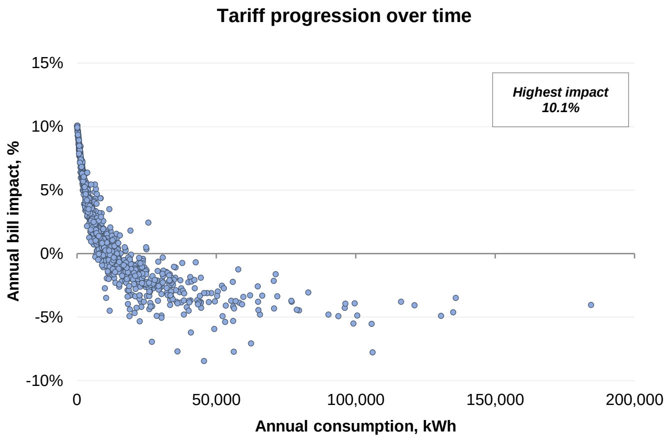


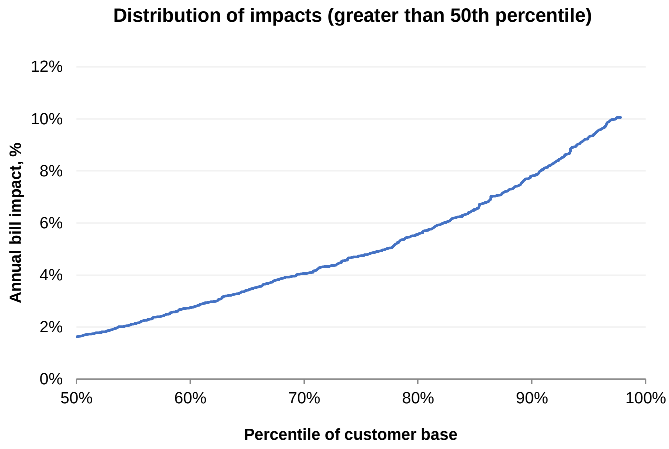


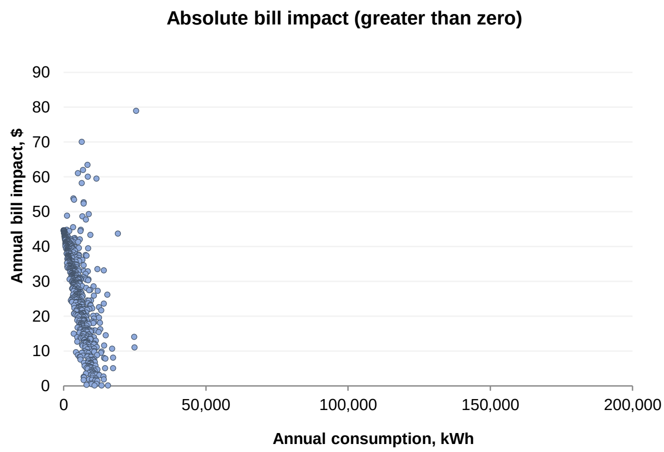


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	60.6%	2.7%	0.0%
Average cumulative bill impact, %	1.6%	4.1%	10.1%	N/A
Average cumulative bill impact, $	($15)	$26	$45	N/A
Average annual consumption, kWh	13,105	4,207	1	N/A
Average maximum demand, kW	8.0	4.5	0.0	N/A
Average load factor, %	19.7%	15.6%	1.7%	N/A

Figure A6.24. Tariff progression over time: EA225 TOU from 2019/20 to 2023/24

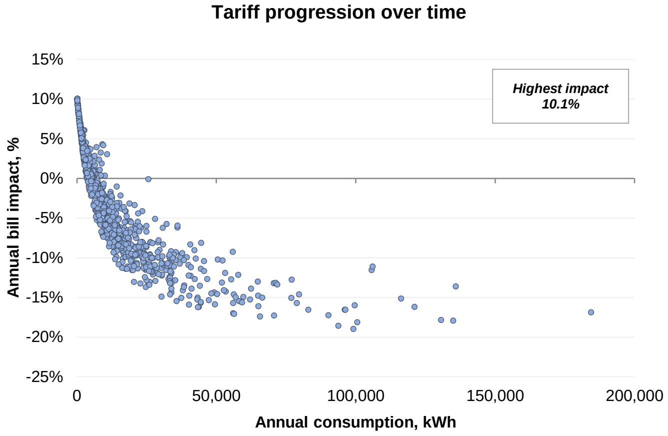


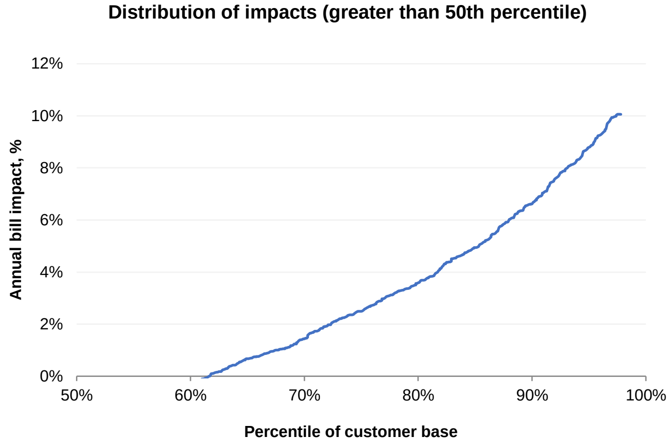


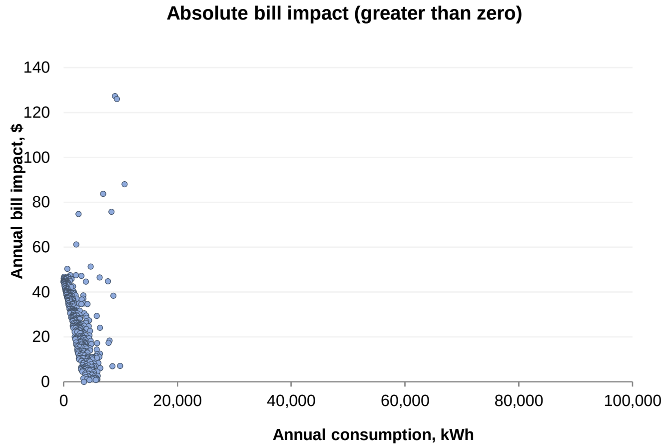


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	66.3%	2.7%	0.0%
Average cumulative bill impact, %	2.0%	4.1%	10.1%	N/A
Average cumulative bill impact, $	($7)	$28	$45	N/A
Average annual consumption, kWh	13,105	4,978	1	N/A
Average maximum demand, kW	8.0	5.1	0.0	N/A
Average load factor, %	19.7%	15.7%	1.7%	N/A

Figure A6.25. Tariff progression over time: EA256 Demand from 2019/20 to 2023/24

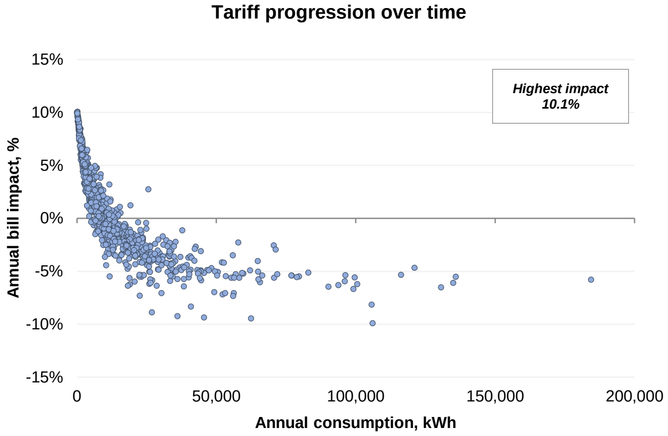


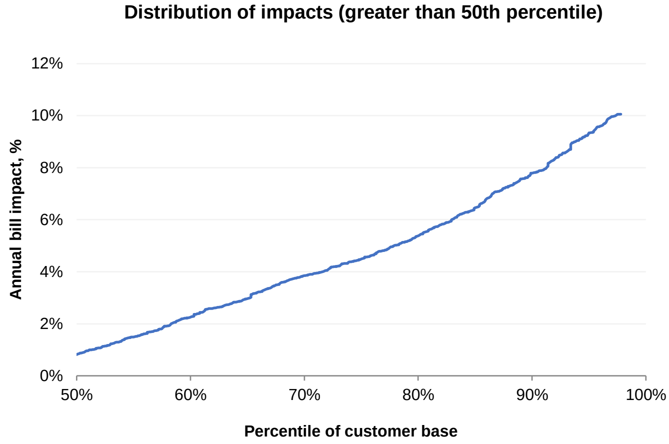


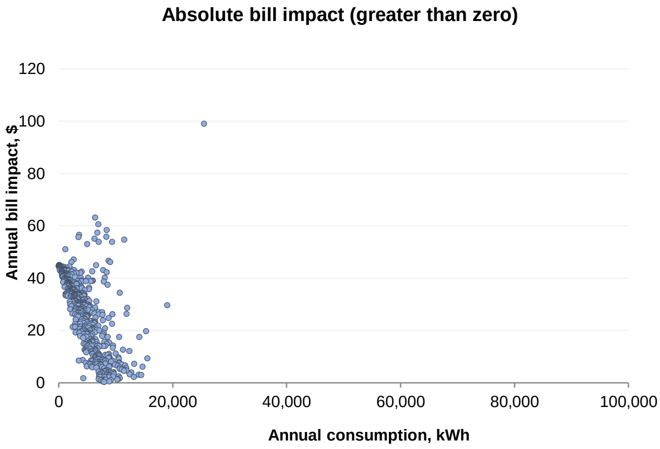


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	38.3%	2.6%	0.0%
Average cumulative bill impact, %	-2.3%	4.4%	10.1%	N/A
Average cumulative bill impact, $	($94)	$27	$45	N/A
Average annual consumption, kWh	13,105	2,532	0	N/A
Average maximum demand, kW	8.0	4.1	0.0	N/A
Average load factor, %	19.7%	13.2%	0.2%	N/A

Figure A6.26. Tariff progression over time: EA255 TOU demand from 2019/20 to 2023/24







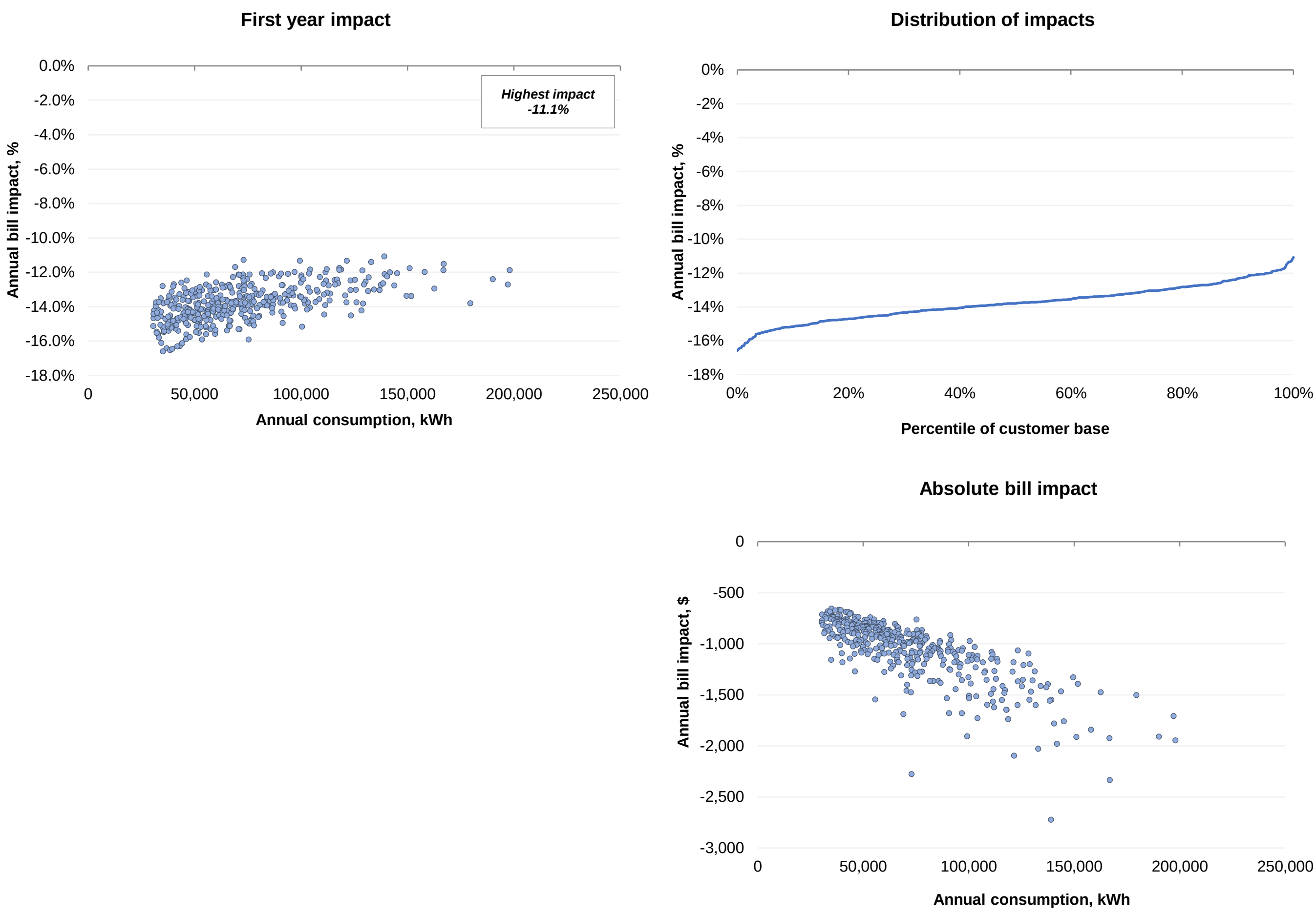
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	58.5%	2.7%	0.0%
Average cumulative bill impact, %	1.3%	4.3%	10.1%	N/A
Average cumulative bill impact, $	($22)	$28	$45	N/A
Average annual consumption, kWh	13,105	4,282	1	N/A
Average maximum demand, kW	8.0	4.9	0.0	N/A
Average load factor, %	19.7%	15.3%	1.7%	N/A

Medium and large business low voltage customer impacts

The following six figures show the impact on customers on three tariffs moving from prices in 2018/19 to new prices in 2019/20 and at the end of the regulatory period in 2023/24.

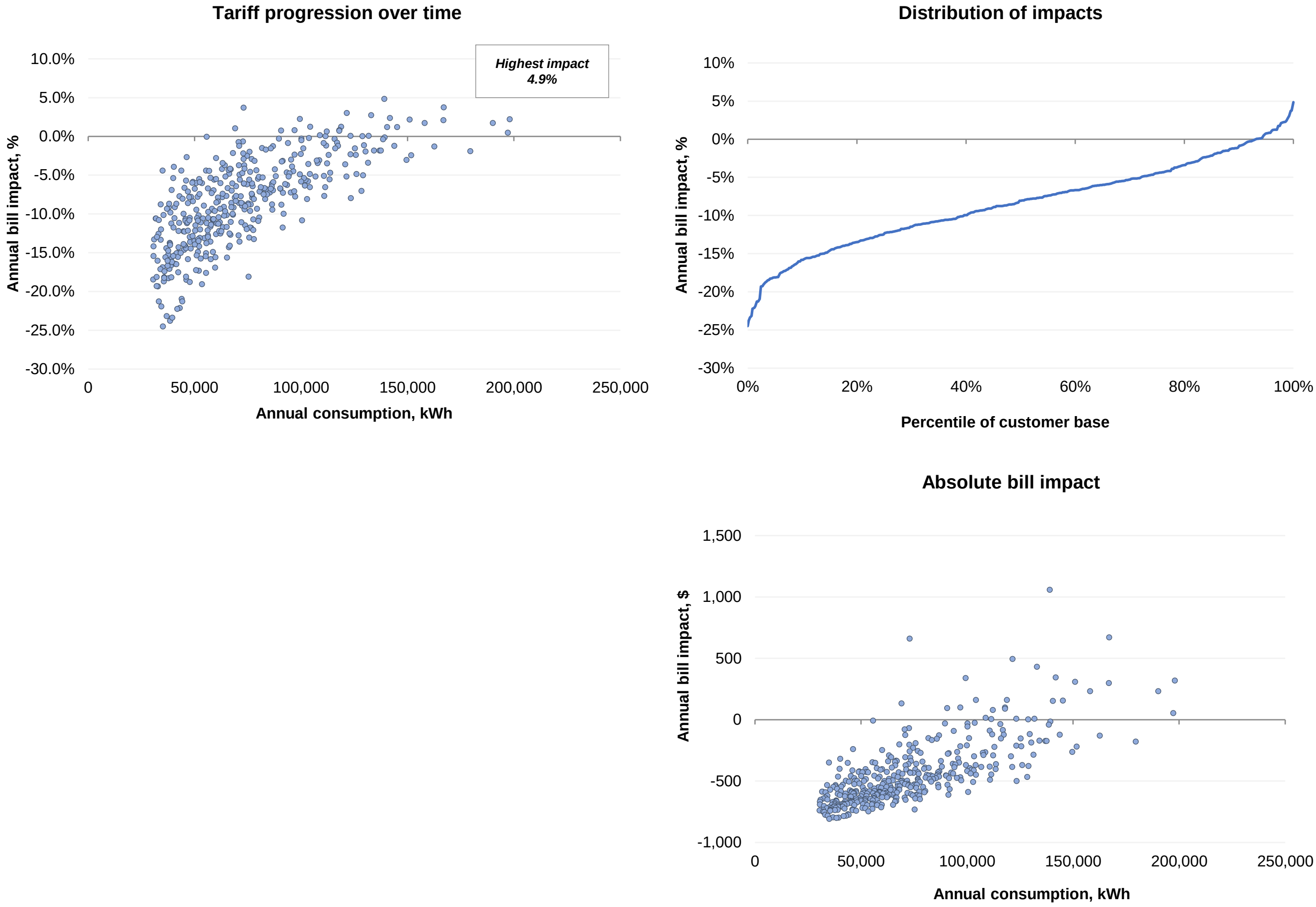
- Figures A6.27 and A6.28: the impact on customers on EA302 40-160 MWh a year of new prices in 2019/20 and at the end of the regulatory period
- Figures A6.29 and A6.30: the impact on customers on EA305 160-750 MWh a year of new prices in 2019/20 and at the end of the regulatory period
- Figures A6.31 and A6.32: the impact on customers on EA310 > 750 MWh a year of new prices in 2019/20 and at the end of the regulatory period.

Figure A6.27. First year impact: EA302 (40-160 MWh pa) from 2018/19 to 2019/20



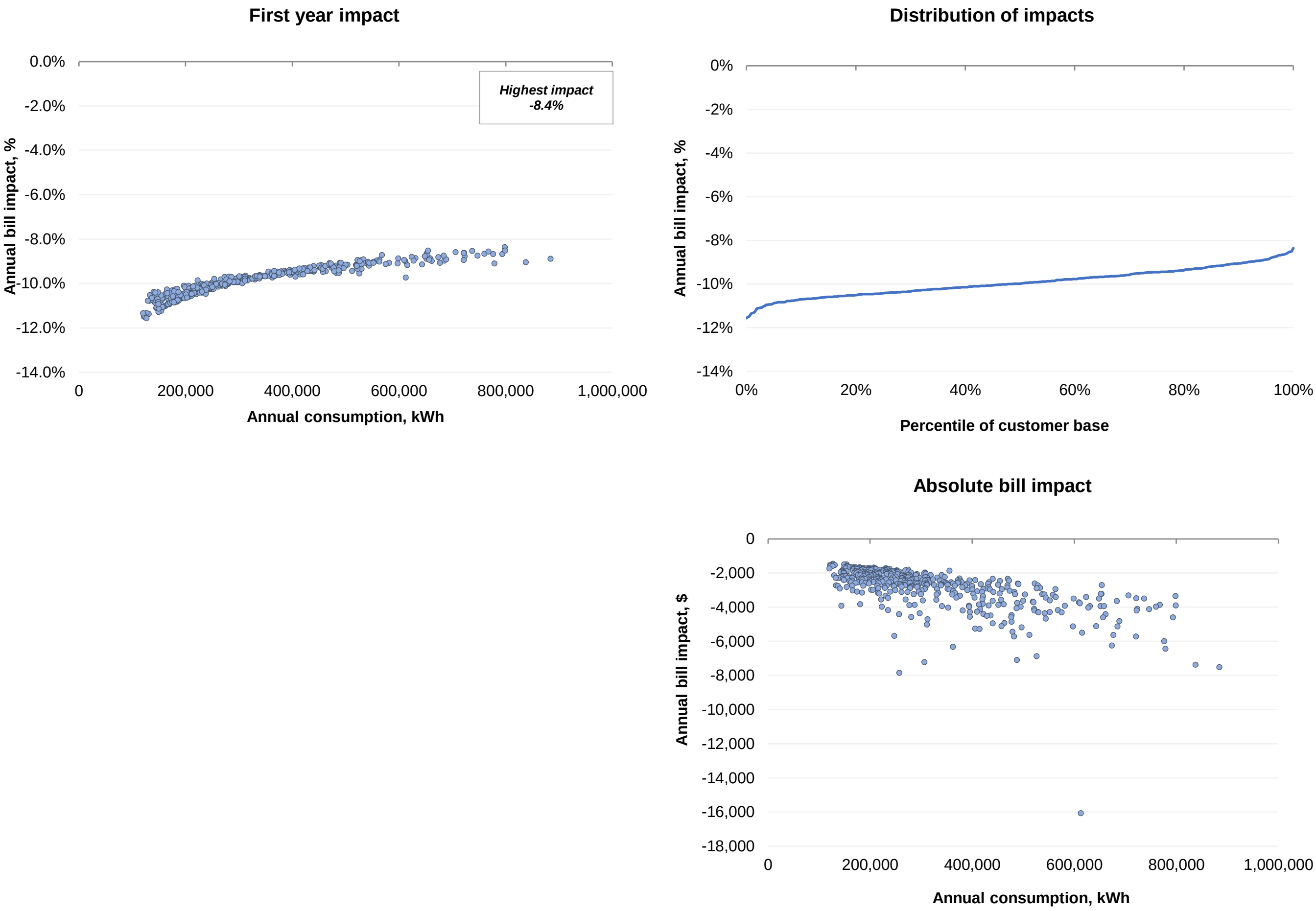
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	0.0%	0.0%	0.0%
Average annual bill impact, %	-13.8%	N/A	N/A	N/A
Average annual bill impact, $	($1,064)	N/A	N/A	N/A
Average annual consumption, kWh	72,391	N/A	N/A	N/A
Average maximum demand, kW	27.4	N/A	N/A	N/A
Average load factor, %	35.7%	N/A	N/A	N/A

Figure A6.28. Tariff progression over time: EA302 (40-160 MWh pa) from 2019/20 to 2023/24



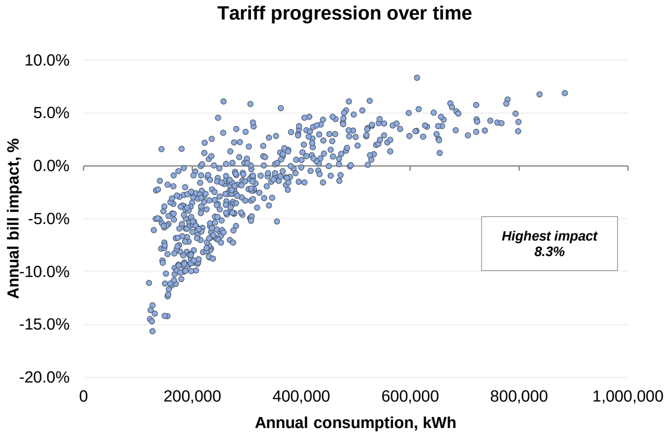
Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	6.9%	0.0%	0.0%
Average cumulative bill impact, %	-8.5%	1.6%	N/A	N/A
Average cumulative bill impact, $	($445)	$243	N/A	N/A
Average annual consumption, kWh	72,391	130,360	N/A	N/A
Average maximum demand, kW	27.4	72.5	N/A	N/A
Average load factor, %	35.7%	22.4%	N/A	N/A

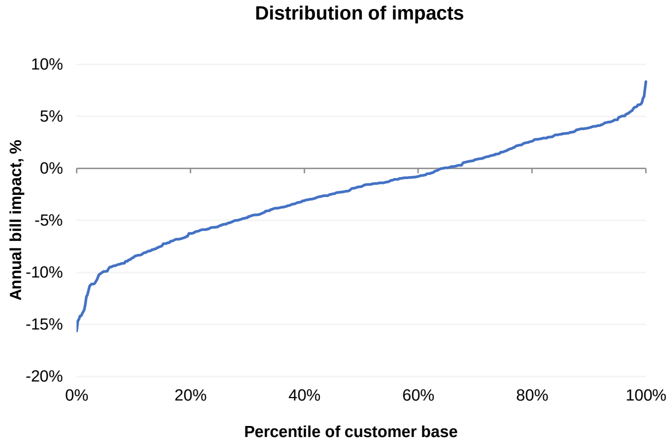
Figure A6.29. First year impact: EA305 (160-750 MWh pa) from 2018/19 to 2019/20

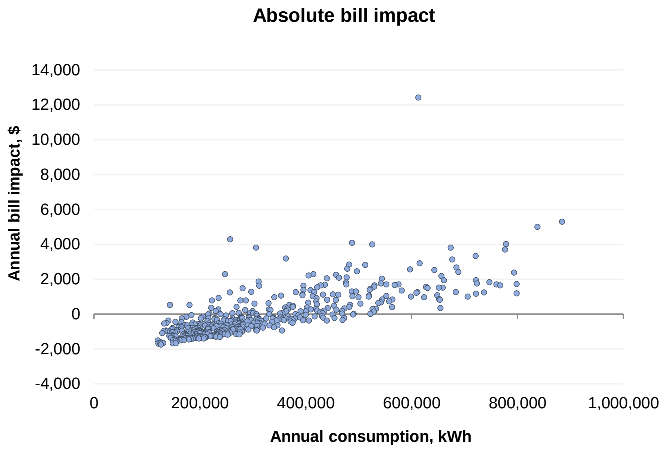


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	0.0%	0.0%	0.0%
Average annual bill impact, %	-9.9%	N/A	N/A	N/A
Average annual bill impact, $	($2,867)	N/A	N/A	N/A
Average annual consumption, kWh	322,616	N/A	N/A	N/A
Average maximum demand, kW	102.8	N/A	N/A	N/A
Average load factor, %	42.7%	N/A	N/A	N/A

Figure A6.30. Tariff progression over time: EA305 (160-750 MWh pa) from 2019/20 to 2023/24

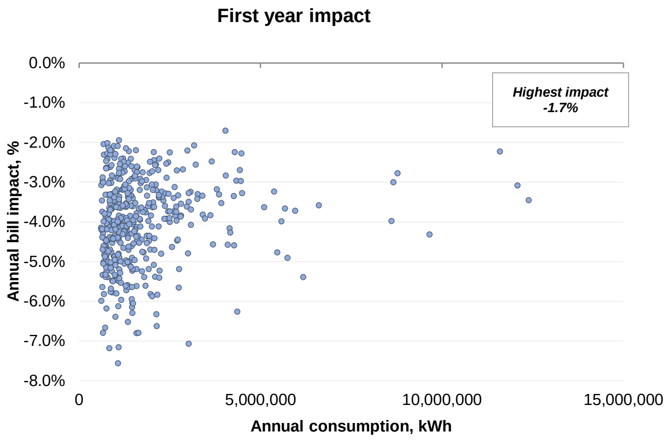


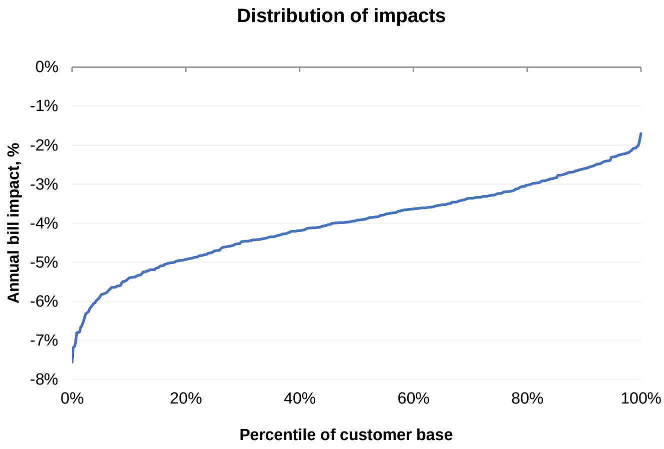


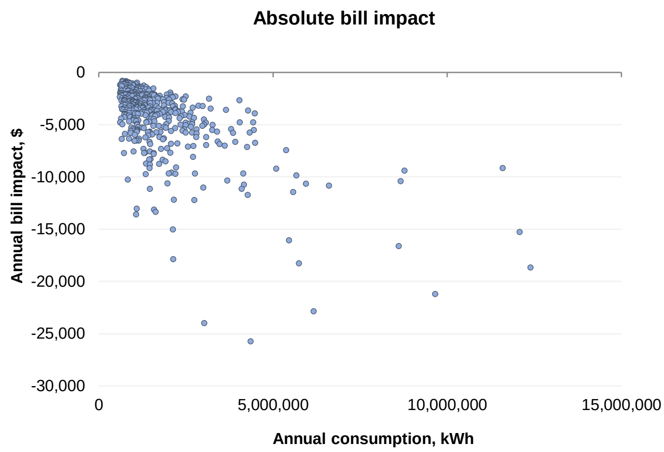


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	35.6%	0.0%	0.0%
Average cumulative bill impact, %	-2.1%	2.9%	N/A	N/A
Average cumulative bill impact, $	($52)	$1,333	N/A	N/A
Average annual consumption, kWh	322,616	477,559	N/A	N/A
Average maximum demand, kW	102.8	170.9	N/A	N/A
Average load factor, %	42.7%	36.3%	N/A	N/A

Figure A6.31. First year impact: EA310 (>750 MWh pa) from 2018/19 to 2019/20

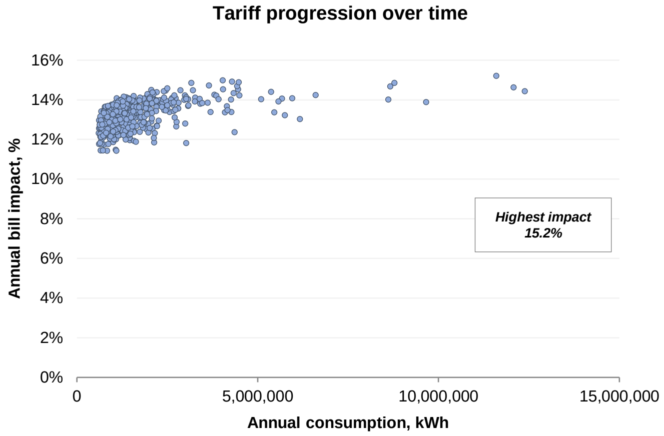


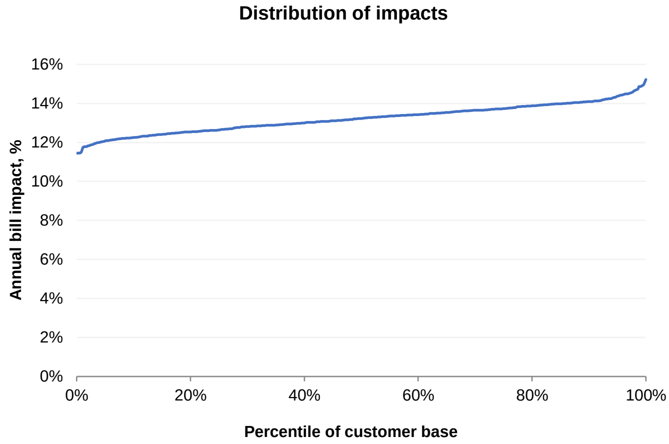


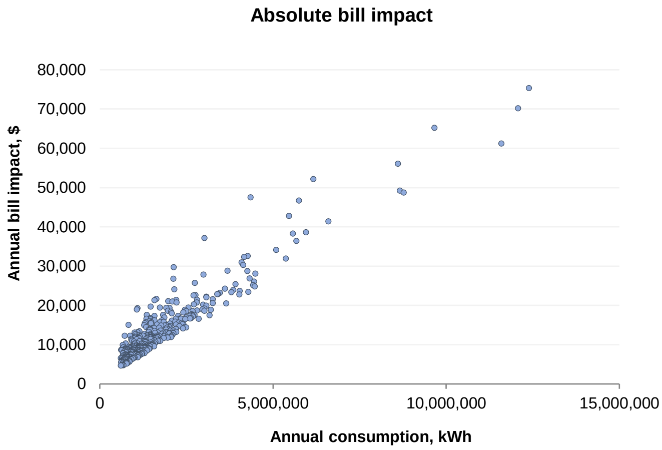


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	0.0%	0.0%	0.0%
Average annual bill impact, %	-4.0%	N/A	N/A	N/A
Average annual bill impact, $	($4,474)	N/A	N/A	N/A
Average annual consumption, kWh	1,760,094	N/A	N/A	N/A
Average maximum demand, kW	466.6	N/A	N/A	N/A
Average load factor, %	46.0%	N/A	N/A	N/A

Figure A6.32. Tariff progression over time: EA310 (>750 MWh pa) from 2019/20 to 2023/24





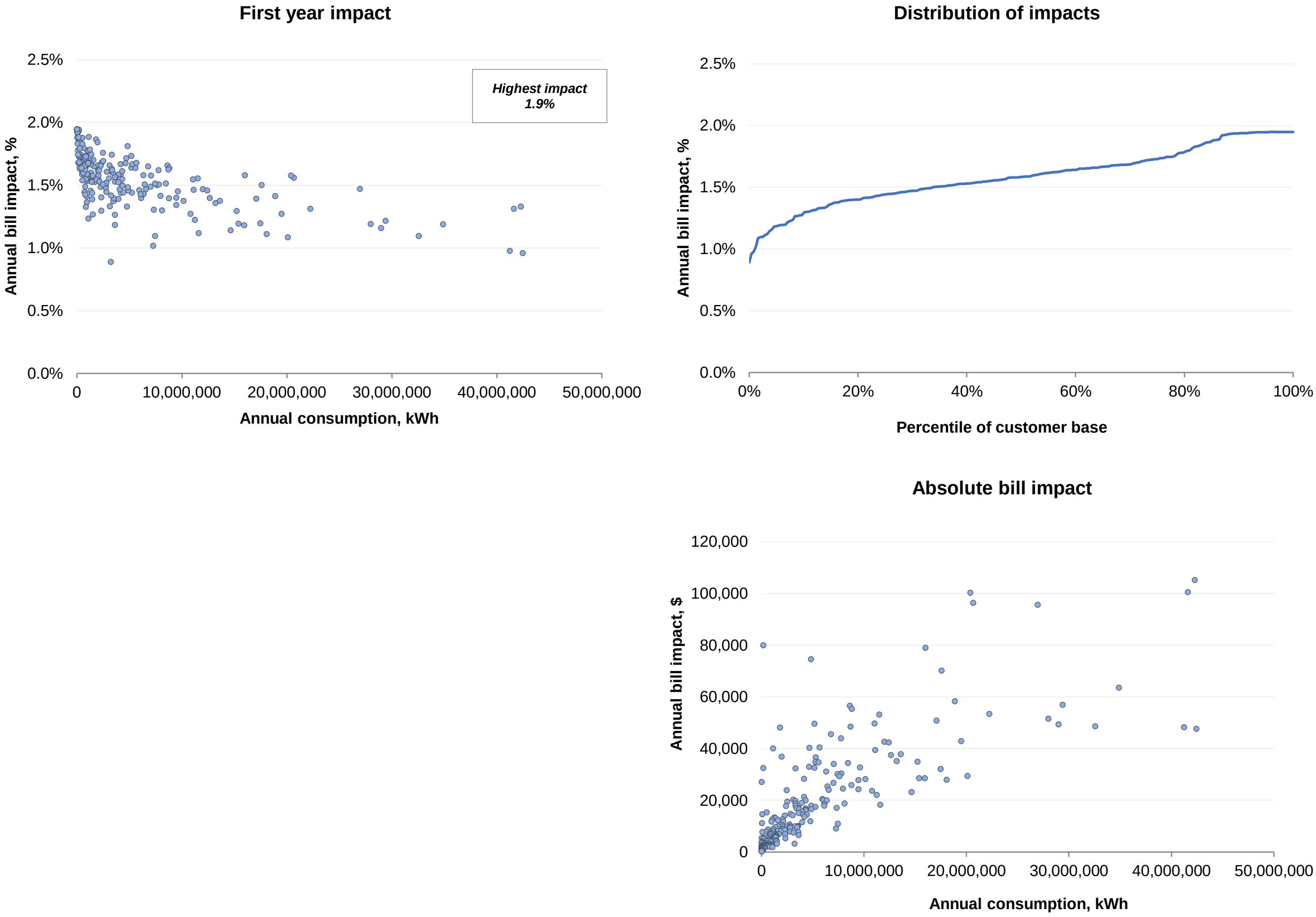


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	100.0%	0.0%
Average cumulative bill impact, %	13.2%	13.2%	13.2%	N/A
Average cumulative bill impact, $	$13,700	$13,700	$13,700	N/A
Average annual consumption, kWh	1,760,094	1,760,094	1,760,094	N/A
Average maximum demand, kW	466.6	466.6	466.6	N/A
Average load factor, %	46.0%	46.0%	46.0%	N/A

High Voltage customer impacts

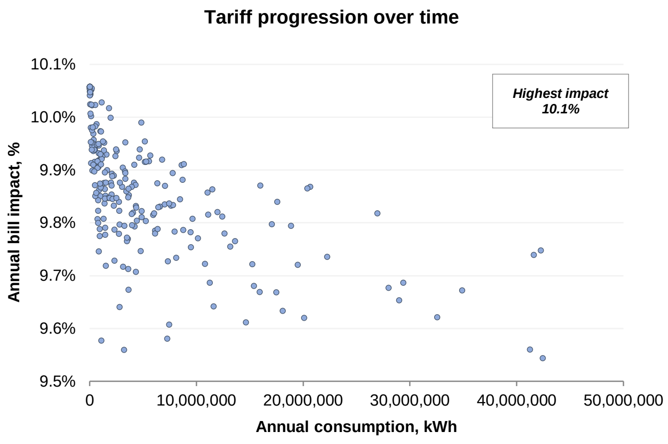
Figures A6.33 and A6.34 show the impact on customers on EA370 High Voltage Connection (system) of new prices in 2019/20 and at the end of the regulatory period in 2023/24. Impacts are based on all customers, not a sample.

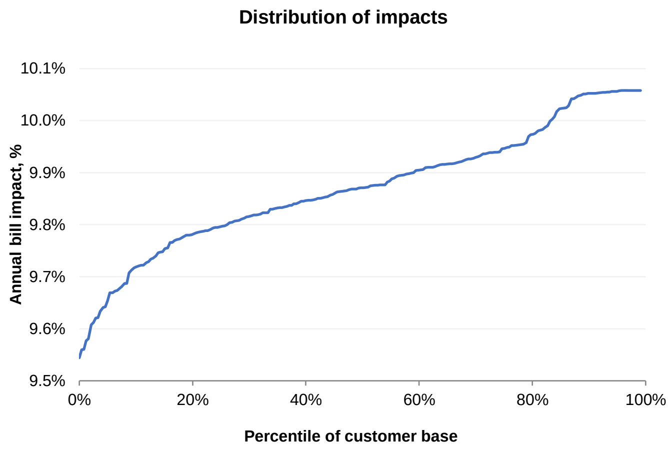
Figure A6.33. First year impact: EA370 (HV Connection System) from 2018/19 to 2019/20

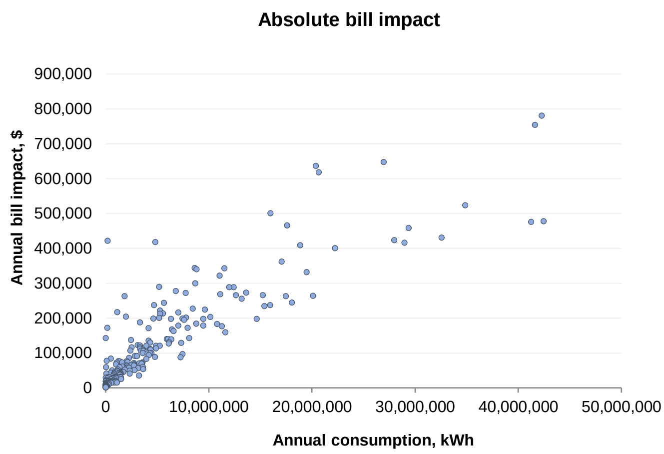


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.0%	0.0%
Average annual bill impact, %	1.6%	1.6%	N/A	N/A
Average annual bill impact, $	$19,031	$19,031	N/A	N/A
Average annual consumption, kWh	5,289,204	5,289,204	N/A	N/A
Average maximum demand, kW	1,336.8	1,336.8	N/A	N/A
Average load factor, %	38.2%	38.2%	N/A	N/A

Figure A6.34. Tariff progression over time: EA370 (HV Connection System) from 2019/20 to 2023/24





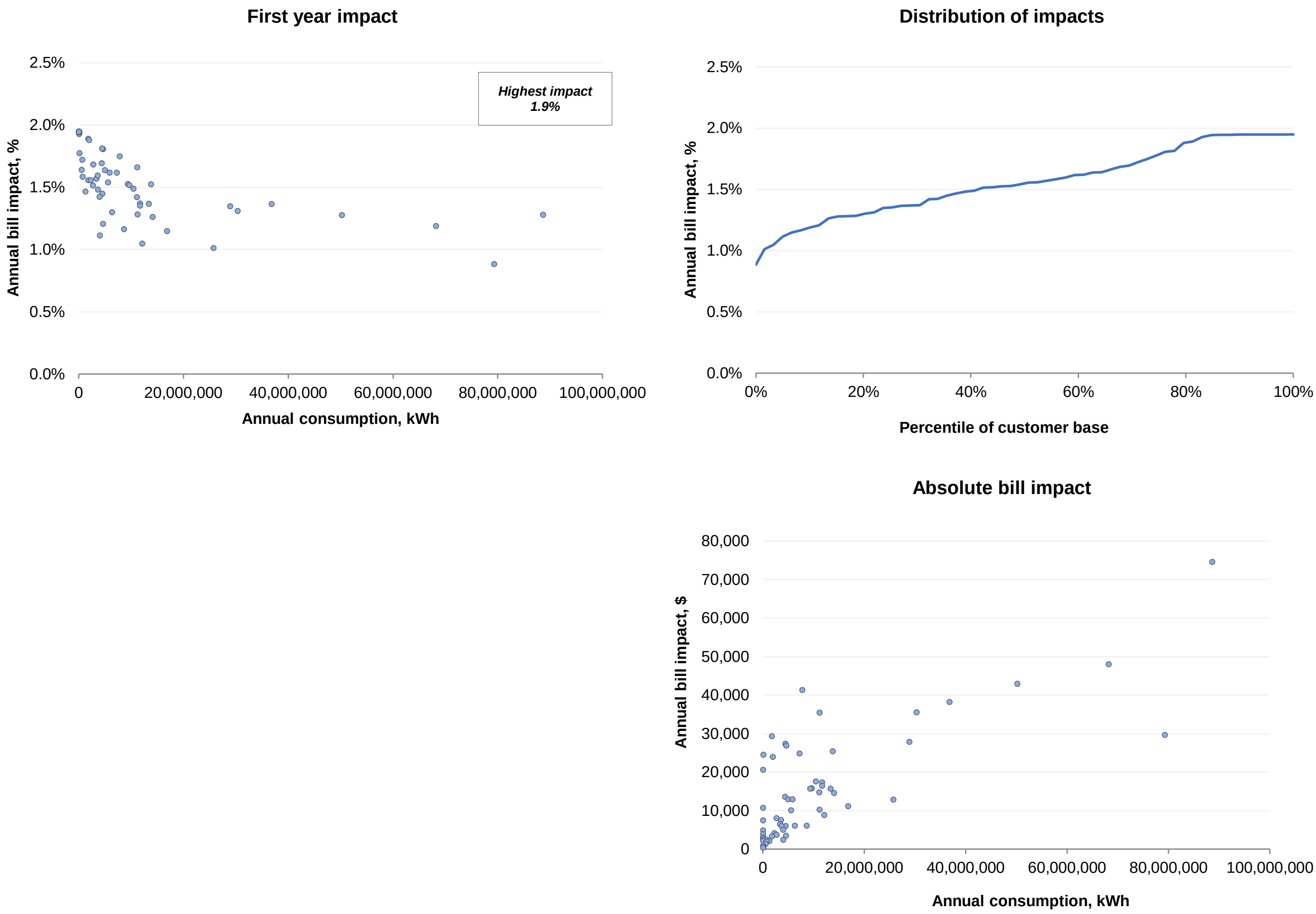


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	16.8%	0.0%
Average cumulative bill impact, %	9.9%	9.9%	10.0%	N/A
Average cumulative bill impact, $	$128,504	$128,504	$44,648	N/A
Average annual consumption, kWh	5,289,204	5,289,204	114,797	N/A
Average maximum demand, kW	1,336.8	1,336.8	335.7	N/A
Average load factor, %	38.2%	38.2%	9.1%	N/A

Subtransmission customer impacts

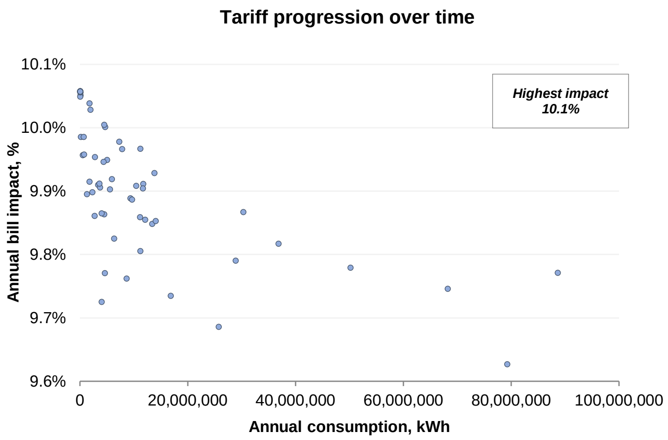
Figures A6.35 and A6.36 show the impact on customers on EA390 ST Connection (system) of new prices in 2019/20 and at the end of the regulatory period in 2023/24. Impacts are based on all customers, not a sample.

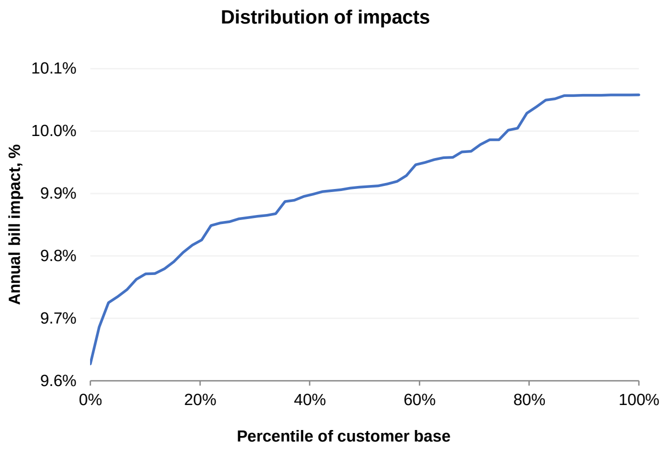
Figure A6.35. First year impact: EA390 (ST Connection) from 2018/19 to 2019/20

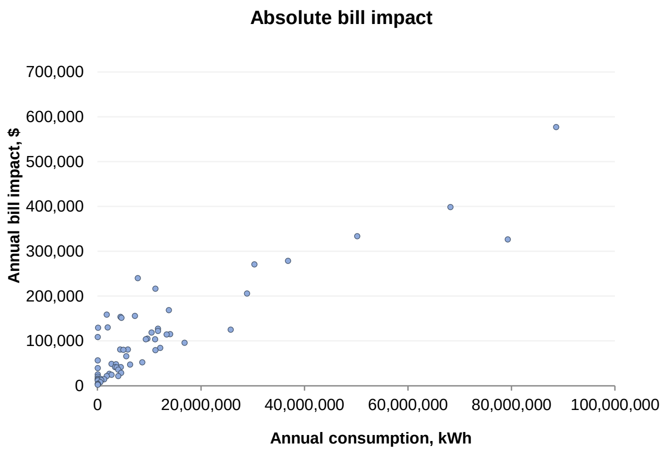


Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	0.0%	0.0%
Average annual bill impact, %	1.6%	1.6%	N/A	N/A
Average annual bill impact, $	$15,229	$15,229	N/A	N/A
Average annual consumption, kWh	11,133,069	11,133,069	N/A	N/A
Average maximum demand, kW	2,889.0	2,889.0	N/A	N/A
Average load factor, %	37.6%	37.6%	N/A	N/A

Figure A6.36. Tariff progression over time: EA390 (ST Connection) from 2019/20 to 2023/24







Summary results	All	Impact > 0%	Impact > 10%	Impact > 20%
Share in sample	100.0%	100.0%	25.0%	0.0%
Average cumulative bill impact, %	9.9%	9.9%	10.0%	N/A
Average cumulative bill impact, $	$105,691	$105,691	$68,405	N/A
Average annual consumption, kWh	11,133,069	11,133,069	865,648	N/A
Average maximum demand, kW	2,889.0	2,889.0	1,261.0	N/A
Average load factor, %	37.6%	37.6%	6.5%	N/A

Spatial analysis of residential customer impacts

The following two figures show the spatial distribution of the impact on residential customers of two types of tariff changes:

- Figure A6.37 shows the impact of opting out from EA025 Time of Use tariff in 2018/19 to EA116 Demand tariff in 2019/20
- Figure A6.38 shows the impact of moving from EA111 Demand (introductory) tariff in 2019/20 to EA116 Demand tariff in 2020/21.

The figures show three levels of bill impacts – a more than 10% decrease (blue dot), a 10% decrease to a 10% increase (grey dot) and a more than 10% increase (red dot) – in areas colour shaded by their level of relative socio-economic disadvantage (darker green for areas of greater relative disadvantage).

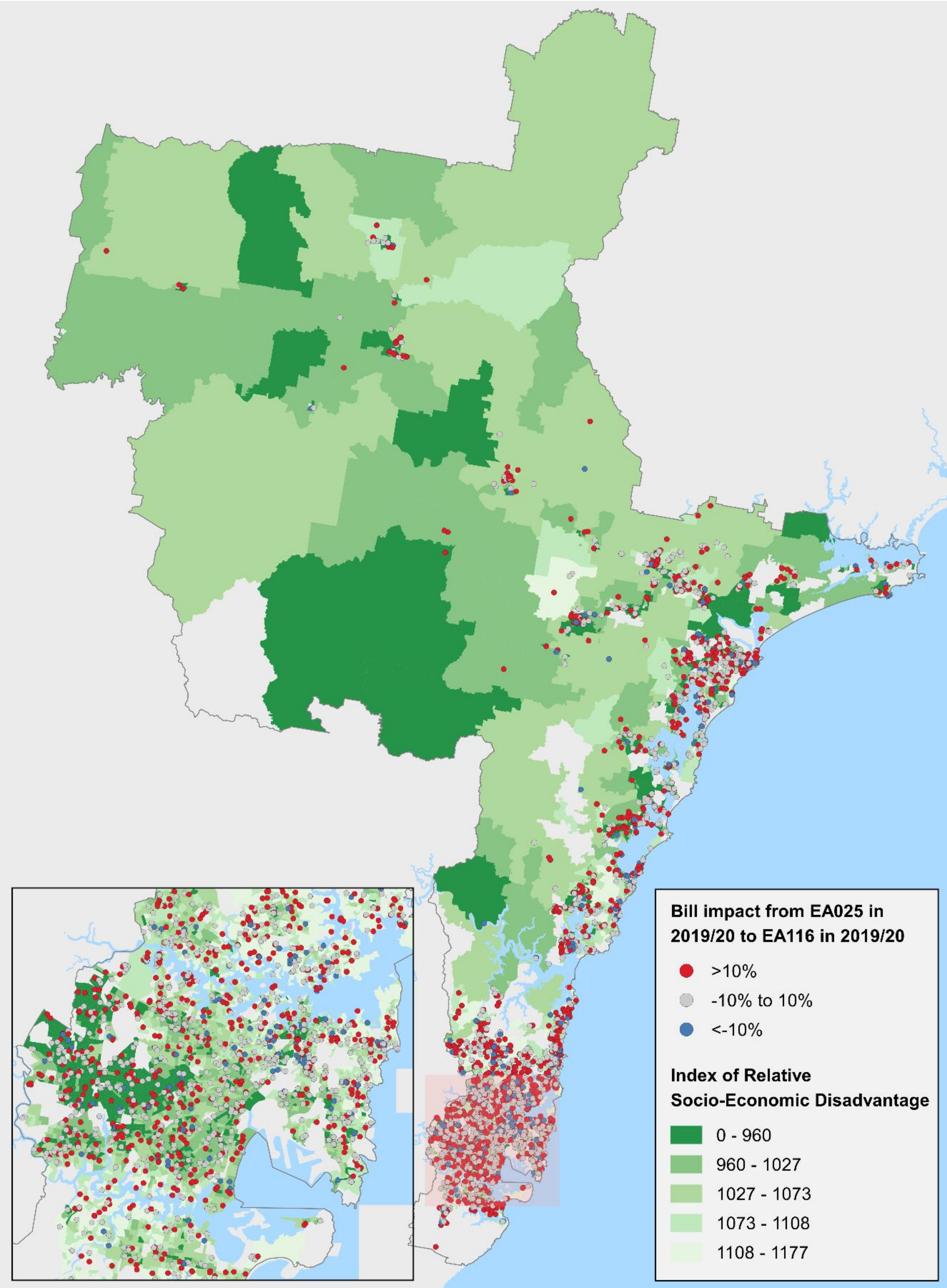
Each dot represents a customer from our sample of 3,500 residential customers and relative disadvantage uses the Australian Bureau of Statistics Index of Relative Socio-Economic Disadvantage[15] which summarises variables that indicate relative disadvantage based on 2016 data. This index ranks areas on a continuum from most disadvantaged to least disadvantaged. A low score on this index indicates a high proportion of relatively disadvantaged people in an area.

Our preliminary analysis indicates that impacts from transition to demand tariffs are geographically dispersed and not concentrated in areas of relative socio-economic disadvantage.

We will do more analysis to segment and identify specific customer groups likely to have adverse impacts and to help co-design targeted complementary measures with customer groups and government.

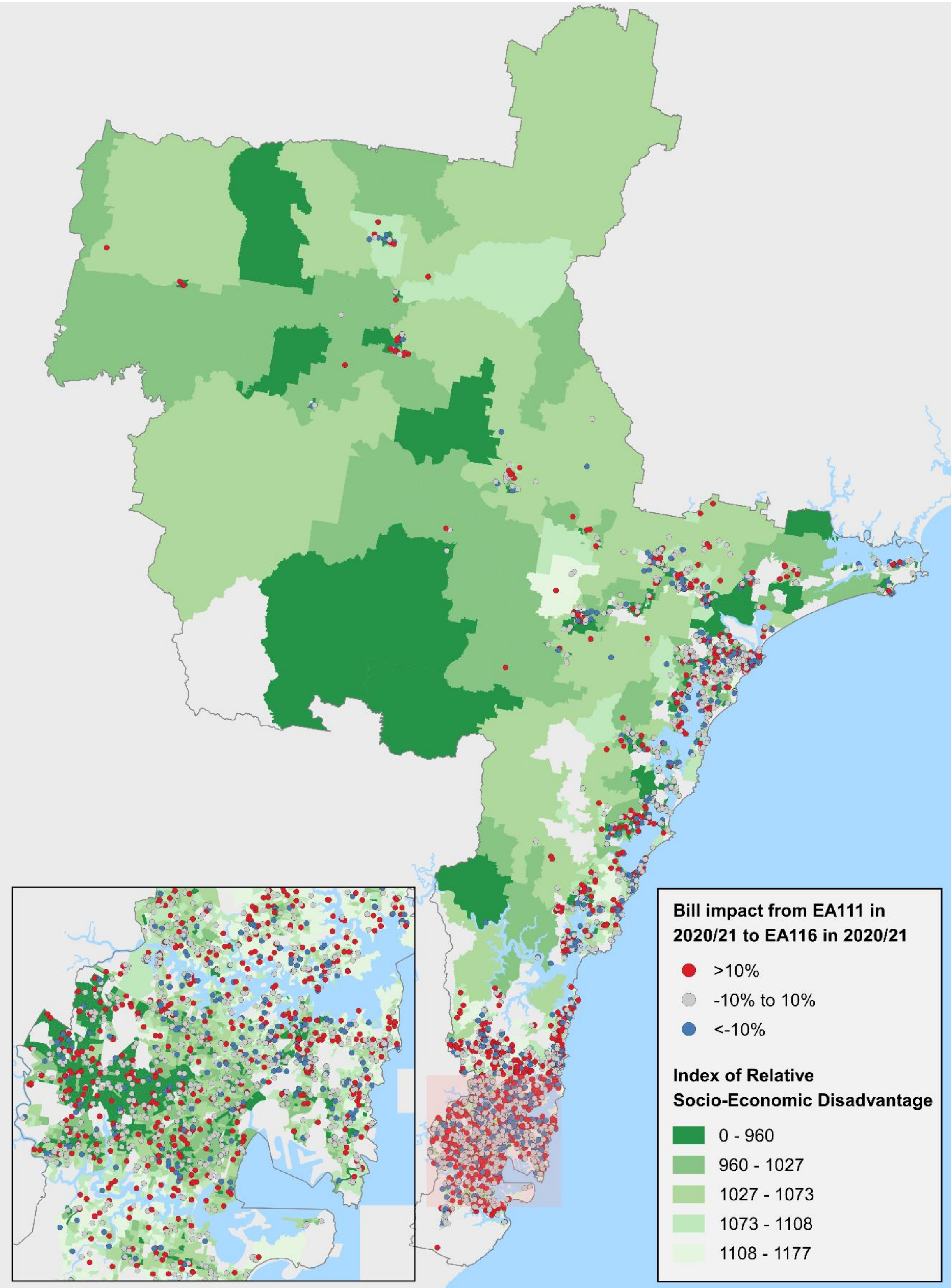
[15] Australian Bureau of Statistics (2018) *Technical Paper: Social and Economic Indexes for Areas (SEIFA) 2016*. Catalogue No. 2033.0.55.001, March 2018.

Figure A6.37. Bill impacts of opting out from EA025 TOU in 2018/19 to EA116 Demand in 2019/20 by Index of Relative Socio-Economic Disadvantage



Note: The Australian Bureau of Statistics Index of Relative Socio-Economic Disadvantage summarises variables that indicate relative disadvantage. This index ranks areas on a continuum from most disadvantaged to least disadvantaged. A low score on this index indicates a high proportion of relatively disadvantaged people in an area. On this figure, there are an equal number of areas in each of the five index categories.

Figure A6.38. Bill impacts of moving from EA111 Demand (introductory) in 2019/20 to EA116 Demand in 2020/21 by Index of Relative Socio-Economic Disadvantage



Note: The Australian Bureau of Statistics Index of Relative Socio-Economic Disadvantage summarises variables that indicate relative disadvantage. This index ranks areas on a continuum from most disadvantaged to least disadvantaged. A low score on this index indicates a high proportion of relatively disadvantaged people in an area. On this figure, there are an equal number of areas in each of the five index categories.

A.7 Complementary measures

Complementary measures can help customers to manage costs, both before and after they receive a bill. There are currently a range of measures available from different sources to assist customers manage their energy costs. These existing measures will be reviewed and extended, and new measures developed to best meet customer needs associated with the introduction of demand tariffs.

Considering types of complementary measures

Complementary measures may include existing and new measures such as:

- Energy efficiency measures and programs with funding for appliances, heating, lighting and cooking including:
    - active monitoring and energy management: in house energy management systems to help customers monitor use in real time
    - energy calculators modified to calculate peak 30 minute cost and help customers choose the most cost reflective retail tariff (similar to a 'green button' initiative)
- Communications campaigns on understanding demand tariffs and customer actions to reduce costs such as Shift, Stagger Save, with online information and tools to help customers understand the energy demand of appliances, manage their usage and assess the best network tariff for particular usage patterns
- Demand management and demand response programs including network-initiated demand reduction (see Section A.2) and customer-initiated demand response through Shift, Stagger, Save
- Technology measures including installation of distributed energy resources supported by existing government rebates, which may include the installation of solar hot water systems or heat pump technology, and could extend to access to community solar and battery storage schemes suitable for those who cannot install distributed energy resources
- Helping eligible customers access existing government rebate schemes.

Government rebates and concessions

There are existing NSW government assistance schemes to assist various types of customers with their energy bills. Retailers such as Energy Australia also offer programs.

Current NSW Government support programs include:

- The **Low Income Household Rebate** helps people who hold eligible concession cards issued by the Commonwealth Department of Human Services or the Department of Veterans' Affairs pay their electricity bill. The rebate is paid as a credit on each quarterly energy bill, up to a total of $285 a year.
- The **Energy Accounts Payment Assistance Scheme** helps people experiencing a short term financial crisis or emergency to pay their electricity or natural gas bill. This scheme is only for short term assistance. Vouchers, each worth $50, are usually paid electronically to retailers, and are distributed by community organisations.
- The **Family Energy Rebate** helps eligible households pay their electricity bill if they have dependent children and received the Family Tax Benefit payment from the Commonwealth Department of Human Services. The Family Energy Rebate gives eligible energy account holders a credit on an energy bill of up to $180.

- The **Life Support Rebate** helps people pay their electricity bills if they are required or have someone living with them who is required to use approved energy-intensive equipment at home. The application form lists the rebate by type of equipment by day. The highest rebate is $3.68 per day for a ventilator or phototherapy equipment, followed by $3.11 for an oxygen concentrator in use continuously for 24 hours a day.
- The **Medical Energy Rebate** helps people who hold eligible concession cards issued by the Commonwealth Department of Human Services or the Department of Veterans' Affairs pay their electricity bill if either they or someone living with them has an inability to self-regulate body temperature when exposed to extremes of environmental temperatures (hot or cold). It is $285 for 2017/18 financial year, paid at $71 per quarter.

Developing complementary measures

We will work closely with stakeholders and customer representatives such as the Energy and Water Ombudsman of NSW, our consultation groups including our Customer Consultative Committee and Pricing Working Group, government and industry to develop and promote a package of complementary measures to support the introduction of demand tariffs and manage customer impacts.

Some measures will be available to all customers, while other measures may have eligibility criteria to target assistance.

Where historical interval demand data is available for a customer undergoing a tariff reassignment (i.e. where it is not associated with a meter upgrade), we will analyse predicted bill impacts based on historical demand. Where we identify customers as likely to experience a network bill increase over a specific threshold to be determined in conjunction with the Pricing Working Group, we will take proactive measures to ensure those customers and/or their retailers are made aware or otherwise supported with targeted complementary measures to mitigate those impacts.

A.8 Glossary

The following terms are used in the Tariff Structure Statement and/or Explanatory Notes.

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Basic accumulation metering	Accumulation meters keep track only of the total accumulated electricity usage. Customers are charged the same amount regardless of when the electricity is used.
CCF	Climate Change Fund
Charging parameter	Pricing component that makes up a tariff.
CRNP	Cost Reflective Network Price. An individually calculated “customised” tariff that is available to transmission-connected sites or certain large loads.
Current Transformer (CT) connection	A connection where the transformer for use with meters and/or protection devices in which the current in the secondary winding is, within prescribed error limits, proportional to and in phase with the current in the primary winding.
Customer class	Refer to Tariff class
Determination	A decision by the AER that determines the revenue allowance for network service providers under the Rules.
Distributed Energy Resources (DER)	Small-scale energy resources such as advanced renewable energy generation and energy storage technologies
Distribution Network Service Providers	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a Network Service Provider.
Distribution-connected sites	Customers that are connected to the electricity distribution network.
DUOS	Distribution Use of System
Efficiency	Signifies a level of performance that describes a process that uses the lowest amount of inputs to create the greatest amount of outputs.
Fixed daily charge	A charging parameter expressed in cents per day. Also known as Network Access Charge.
High voltage tariff	A tariff that applies to connections that are connected at high voltages 5kV, 11kV or 22kV (as measured at the metering point) that is neither a Subtransmission nor a CRNP tariff.
Interval meter	A meter that records how much electricity is used every 30 minutes.
Low voltage tariff	A tariff that applies to connections that are connected at low voltages 230V or 400V (as measured at the metering point).
LRMC	Long Run Marginal Cost
Metering point	The physical point of connection between the Consumers Mains and the electrical network. Each separate overhead or underground service is a separate connection point. Each separate busbar or direct cable supply from a single substation is a separate connection point, e.g. two busbar supplies equal two connection points.
Metering services	Services that measure the customers’ energy consumption and can assist customers to better understand and manage their energy usage.
National Electricity Law	The National Electricity Law set out in the schedule to the National Electricity (South Australia) Act 1996 (SA) and applied in each of the participating jurisdictions.
National Electricity Rules	Refers to the National Electricity Rules (Rules) which governs the operation of the National Electricity Market. The Rules have the force of law and are made under the National Electricity Law.
Network services	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.

NUOS	Network Use of System price, which is composed of DUOS, TUOS and CCF prices.
Phase	As defined in the *Service and Installation Rules of New South Wales August 2012.*
Primary tariff	A network use of system tariff payable by a customer that relates to the principal load of a Distribution Customer
Public lighting services	Services that involve maintaining and improving the standards of streetlights on behalf of local councils, community associations and statutory authorities across Ausgrid's network.
Single phase connection	Refer to Phase
Subtransmission voltage tariff	A tariff that applies to connections that are connected at subtransmission voltages 33kV or greater (as measured at the metering point).
Tariff	The monetary value assigned to individual charging parameters (i.e. cents per kVA or cents per day).
Tariff class	A class of retail customers for one or more direct control services who are subject to a particular network tariff or particular network tariffs as defined in the Rules.
Tariff code	A unique code that identifies each different network tariff.
TSS	Tariff Structure Statement referred to in clause 6.18.1A in the Rules that has been approved by the AER for that Distribution Network Service Provider.
Three phase connection	Refer to Phase
Time of Use (TOU) tariff	A tariff with a structure that applies a different price for energy consumed at times of the day.
Transmission-connected sites	Customers that are connected to the electricity transmission network.
TUOS	Transmission Use of System
Type 5 meter	A metering installation containing an electronic meter, or meters, capable of recording electrical energy consumption in 30 minute market intervals in accordance with the Rules. Such meters are read manually by meter readers. Data is down-loaded via probes into a hand-held data collection device carried by Ausgrid meter readers. Also known as an MRIM, TOU or interval meters.
Type 6 meter	A metering installation containing a meter, or meters, (electronic or electromechanical) capable of recording cumulative electrical energy consumption only. Such meters are read manually by Ausgrid meter readers who record the total cumulative consumption readings displayed on the Type 6 meter register. All meters can support a Type 6 Installation, but they are predominantly installed with mechanical meters or simple electronic meters. Also known as BASIC, Flat Rate or accumulation meters.
Unmetered tariff	A tariff for unmetered supply

A.9 List of attachments and status

This document, our Tariff Structure Statement including Appendix A Explanatory Notes, is Attachment 10.01 to our Revised Proposal. Other attachments referred to in this document and part of our Revised Proposal are listed below. Attachments in bold have been revised for our Revised Proposal or are new. The amendment to the TSS includes Appendix B Explanatory Notes to the Amendment.

Attachment	Status
This document is **10.01 Tariff Structure Statement**	Revised, split into two documents including Appendix A Explanatory Notes
10.02 Procedure for Assigning Customers to a Tariff Class	No change from Initial Proposal
10.03 Long Run Marginal Cost Model	No change from Initial Proposal
10.04 Long Run Marginal Cost Methodology Report	No change from Initial Proposal
10.05 Tariff Model (Standard Control Services)	Revised to reflect our Revised Proposal
10.06 ES7 Network Price Guide, July 2019	Revised to reflect our Revised Proposal
10.07 Price Elasticity	No change from Initial Proposal
10.08 Transmission Pricing Methodology	No change from Initial Proposal
10.09 Methodology for Avoided TUOS Charges	No change from Initial Proposal
10.10 Indicative Pricing Schedule – DUOS Charges	Revised to reflect our Revised Proposal
10.11 Indicative Pricing Schedule – TUOS Charges	Revised to reflect our Revised Proposal
10.12 Indicative Pricing Schedule – ACS Charges	Revised to reflect our Revised Proposal
10.13 Indicative Pricing Schedule – Climate Change Fund	Revised to reflect our Revised Proposal
10.14 Pricing Directions: A Stakeholder Perspective	No change from Initial Proposal
10.15 Energy Volume Forecast, January 2019	New for Revised Proposal

Amendment to the Tariff Structure Statement 2019-24 – Explanatory Notes to the Amendment

September 2019

APPENDIX B – EXPLANATORY NOTES TO THE AMENDMENT

These Explanatory Notes to the Amendment provide additional information to support our proposed Amendment to the Tariff Structure Statement. The Explanatory Notes to the Amendment are structured in the same way as the Explanatory Notes for the approved TSS 2019-24.

APPENDIX B – EXPLANATORY NOTES TO THE AMENDMENT

B.1 Overview

Why an amended Tariff Structure Statement?

We are seeking the AER's approval to amend our Tariff Structure Statement for the 2019-24 regulatory control period, approved by the AER in April 2019 (referred to as 'approved TSS for 2019-24', or 'April 2019 TSS'). We seek this amendment under cl 6.18.1B of the National Electricity Rules (NER, or 'the Rules').

We make this request by enclosing the proposed amended TSS (cl 6.18.1B(b)(1)). This document Explanatory Notes to the Amendment (Appendix B) is structured identically to the Explanatory Notes to the TSS (Appendix A), to enable easy mapping of the new material. If our proposed amendment is accepted, our amended TSS would replace our April 2019 TSS.

The events that caused Ausgrid to seek an amendment to the TSS were:

- The Australian Energy Market Commission (AEMC)'s final report *Updating the Regulatory Frameworks for Embedded Networks* (June 2019) and the proposed rule change on the regulatory framework for embedded networks (ENs). The outcomes of this review could not have been reasonably foreseen at the time of our revised TSS submission in January 2019.

- The acceleration of the pace of creation of new ENs, and conversion of existing connections to form ENs, in our distribution area.

- The AER's rejection in April 2019 of our placeholder EN tariff proposed in our revised TSS in January 2019.

These events were beyond our reasonable control (cl 6.18.1B(b)(2)(i)) and could not have been reasonably foreseen by Ausgrid at the time of the TSS approval in April 2019. Box B1.1 below provides a timeline of key regulatory events supporting our argument.

The difference between the approved TSS (April 2019) and the proposed amended TSS is the default tariffs for ENs presented in this document (cl 6.18.1B(b)(3)).

We are proposing an EN tariff to improve the efficiency of our tariffs and ensure a fair contribution to funding network costs by all customers. Under current arrangements, the cost of running the distribution network is not shared equitably between customers within ENs and those outside ENs. We are pioneering an EN tariff through this amendment to protect the long-term interests of current and future customers who share our network assets. Importantly, because our revenues are subject to a revenue cap, this new tariff will not result in us earning more revenue. We are seeking this amendment in the interest of our customers who are effectively cross-subsidising ENs under the current tariff arrangements

To support our EN tariff we provide:

- evidence that the proposed tariffs are more cost-reflective than existing arrangements

- information on the existing ENs operating on the network

- analysis of EN and average customer including consumption, load shape and diversity, and

- evidence that the proposed tariffs will promote efficient competition for the EN services.

In providing this analysis, we are guided by the AER's response to TasNetworks initial proposal of an EN tariff that was not pursued further,[1] and the AER's final decision on our TSS that rejected the placeholder EN tariff.[2]

We have consulted with our customer groups and retailers (Customer Consultative Committee, 25 July 2019, and Pricing Working Group on 12 August 2019, and the Customer Consultation Forum on 17 September 2019) in developing the proposed amended TSS. Concerns raised by our customers and our proposed response to those concerns are discussed in section B.3 (cl 6.18.1B(b)(6)).

Key benefits of introducing EN tariffs

With this proposed amendment, our TSS would better comply with pricing principles for direct control services, because the new EN tariffs are:

- addressing the growth of ENs within the Ausgrid distribution area
    - We have experienced a consistent over-forecasting of our residential customer numbers coincident with the increase in the ENs in our distribution area. For the remainder of the current regulatory period, our proposed amendment will ensure that revenue collected from C&I tariffs, including the revenue from the new EN tariffs, when summed up with the revenue expected to the received from all other tariffs, permit us to recover our expected allowed revenue (cl 6.18.5(g)(2)).
- improving the efficiency of our tariffs
    - The efficiency of our tariffs would improve by ensuring that customers with similar load profiles are treated in a similar way. We have conducted analysis and demonstrated that ENs are different from the commercial and industrial (C&I) customers in their load profile, peak consumption and diversity (the timing of their peak). Our tariffs become more efficient if the difference between ENs and C&I customers is recognised (cl 6.18.1B(b)(5)).
    - We are continuously assessing contribution of tariffs and tariff classes to peak demand and will be revising allocation of costs to these tariffs in line with the change in these contributions. Our pricing will reward customers for reduction in their peak demand.
- ensuring fair contribution to funding network costs
    - The fairness of contribution to funding network costs will improve, ensuring that our existing customers do not cross-subsidise ENs. Our proposed EN tariffs help make ENs contribute more equitably to postage stamp pricing and universal service obligations that we are required to deliver to our customers.
    - Non-EN customers are effectively subsidising ENs. While unable to remove the cross-subsidy completely, the proposed tariffs improve efficiency by bridging the gap between the costs recovered from essentially similar customers within and outside ENs.
    - Our new residential and small business demand tariffs introduced from 1 July 2019 create incentives for conversion of the existing high density residential and commercial precincts into ENs. The benefits of demand tariffs should be shared with our broader customer base, including with customers on legacy tariffs that bear the large proportion of total network costs.

[1] AER (2018) *Draft Decision TasNetworks Distribution Determination Attachment 18 – Tariff Structure Statement,* pp 18-28 and 18-29.

[2] AER (2019) F*inal Decision – Ausgrid Distribution Determination 2019 to 2024, Attachment 18 Tariff Structure Statement*, April 2019, p 219.

- promoting entry of efficient EN service providers
    - The EN tariff supports efficient competition in the EN market by replicating the outcome of applying the efficient component pricing rule (ECPR) that encourages efficient entry into downstream market. Our rationale for this tariff is supported by the NSW IPART's decision to apply 'retail minus' to wholesale customers in water and wastewater industry, as the only approach compatible with postage stamp price regulation.
    - The proposed new tariff would ensure that conversions to ENs occur only if they are efficient and provide value added services to end customers that future members of the EN are willing to fund, without any cross-subsidy from our existing customer base.

This is a good fit with our tariff reform focus on cost reflective tariffs and demand response through behavioural change or technical measures.

Stakeholder feedback on the EN tariff and grandfathering provisions

Stakeholder consultation provided valuable feedback which has shaped and improved our proposed tariff approach. We consulted on a secondary tariff for ENs based on a fixed charge applied to the forecast number of child connections, by child connection type. Through consultation stakeholders pointed out the difficulty of implementing the secondary tariff in the way proposed, especially to establish clear and transparent processes to determine actual child numbers.

In response to stakeholder feedback, we converted the secondary tariffs we consulted on into a primary EN tariff that is more cost reflective for these customers based on the nature of their usage. It also rewards EN customers for reducing their peak demand.

We propose a new primary tariff for ENs as a default assignment for new ENs energised after 1 July 2020, and existing ENs upgrading or modifying their connection after 1 July 2020, unless exempt under the AER's Registration Exemption Guidelines valid at the time of energisation or connection change.[3]

We include this exemption provision in response to our stakeholders concerns about the potential impact of the EN tariff on within-EN customers if the costs are passed through by the EN operators. Customer representatives in the Pricing Working Group, especially Energy Consumers Australia (ECA), raised concerns on the potential impact on vulnerable customers, such as caravan park residents. At the same time, they did not support grandfathering all existing ENs as this would lock in the current level of cross-subsidy that our customers do not find acceptable.

EN customers were critical of the proposed tariff and supported grandfathering should the secondary tariff be introduced.

We agree that without the safety net provided to within-EN customers by exposure to retail competition, our proposed EN tariff could result in the price increase to within-EN end users. We note that the AEMC decided to exclude legacy ENs subject to deemed and individual exemptions from the transitional framework.

We propose that legacy ENs remain on the C&I tariff appropriate to the extent of their usage and are grandfathered from the new EN tariff until they modify or upgrade their connection after 1 July 2020, unless exempt under the new AER Exempt Network Guidelines valid at the time of connection change.

We have considered impacts on our EN customers and on our broader customer base (cl 6.18.5(d)) (see section B.6).

[3] The current version of the AER Exemption Guidelines is AER (2018), *Electricity Network Service Provider - Registration Exemption Guideline,* Version 6, March 2018, to be revised in line with the updated regulatory framework.

Ausgrid pioneers this reform not to benefit from it, but to protect the long-term interest of its current and future customers who share the network assets. The proposed change will have implications for other distributors who are grappling with the similar issues in their distribution areas.

Box B1.1. Timeline of key regulatory events preceding this proposed amendment

- On 26 January 2017, AEMC commenced review of regulatory arrangements for ENs on request from the Council of Australian Governments (COAG) Energy Council.
- On 28 November 2017, AEMC concluded its review of regulatory arrangements for ENs and found current regulatory arrangements are not fit for purpose.
- On 30 April 2018, Ausgrid submitted an initial regulatory proposal to the AER for the 2019-24 regulatory control period.
- On 30 August 2018, AEMC commenced work to provide advice to governments on a new regulatory framework for ENs.
- On 30 October 2018, AER published its draft decision on Ausgrid's 2019-24 Revenue Determination and draft TSS. The AER did not approve key features of Ausgrid's draft TSS, including tariff assignment policy and the lack of a demand tariff.
- On 8 January 2019, Ausgrid submitted its 2019-24 Revised Proposal and Revised TSS to the AER. The revised TSS was a substantially new TSS that offered a suite of residential and small business demand tariffs. It also contained a placeholder EN tariff.
- On 31 January 2019, AEMC published a draft report for its review into a new regulatory framework for ENs.
- On 30 April 2019, AER published its final decision on Ausgrid's 2019-24 Revenue Determination and TSS. The AER did not approve the placeholder EN tariff.
- On 20 June 2019, AEMC published its final report with a new regulatory framework for ENs. The framework included a shadow network tariff for customers that go on market.
- July – September 2019 Ausgrid's consulted on the proposed EN tariff, including:
    - 25 July 2019 - Customer Consultative Committee
    - 12 August 2019 - Pricing Working Group
    - 17 September 2019 - Customer Consultation Forum.
- On 30 September 2019 – Ausgrid lodged this application to amend the TSS with the AER.

AEMC report is the trigger event for us to seek amendment

We expect changes to regulation of ENs in the 2019-24 regulatory period which will result in better protections and access to more competitive retail offers for consumers in ENs. The AEMC recommended new regulatory arrangements for ENs in its final report in November 2017[4].

[4] AEMC (2017) *Review of Regulatory Arrangements for Embedded Networks*, Final Report, 28 November 2017.

Following that report, a 2019 review by the AEMC has identified a package of law and rule changes required to implement these recommendations to update the regulatory frameworks that apply to ENs. The AEMC's draft report on updating the regulatory frameworks for ENs was released in January 2019[5] and the final report in June 2019.[6] AER's final decision on our revised TSS was made in April 2019, before the outcome of the AEMC review became known.[7]

On 20 June 2019 the AEMC published the final report for its review into updating the regulatory arrangements for ENs.[8]

The AEMC's recommendations are significant and driven by the needs of customers and not the business model of suppliers. Proposed regulatory changes include:

- improved consumer protections
- financial and data transfer processes to help drive competition
- metering obligations
- rights when upgrading connections, and
- improved access to concession schemes.

ENs would be elevated into the national regulatory frameworks, including through the registration of embedded network service providers (ENSPs), the authorisation of on-selling retailers and the extension of standard NEM metering arrangements to ENs.

AEMC's 'shadow price' highlights arbitrage of network charges

AEMC's final report recommends standardised billing arrangements for the recovery of external network charges from EN customers who choose to go 'on-market' with an alternative retailer.

The AEMC believes the introduction of standardised billing arrangements for the recovery of external network charges from EN customers who choose to go 'on-market' with an alternative retailer will support retail competition. These retailers purchase electricity directly from the NEM and sell it to the EN customer, rather than on-sell electricity bought at the connection point of the EN to the Local Network Service Provider's (LNSP's) distribution network. As a result, the external network charges are still paid by the exempt ENSP at the connection point to the LNSP's distribution network.

Currently, retailers are required to manually process and manage a large amount of transactions for exempt network service providers. This deters consumers from accessing retail market competition and being able to choose a market offer with an alternative retailer outside the EN. The AEMC developed a new framework to resolve this for ENSPs registered under the new framework and existing exempt network service providers by:

- setting network charges at a level no greater than the amount that the customer would have paid had it been directly connected to the LNSP's distribution network to which the EN is connected (the 'shadow price')
- using standardised processes and data formats to bill retailers these charges for on-market customers.

The AEMC's recommendation is to assign the role of billing NEM retailers for on-market customers to ENSPs.

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5 AEMC (2019) *Updating the Regulatory Frameworks for Embedded Networks*, Draft Report, 31 January 2019.
6 AEMC (2019) *Updating the Regulatory Frameworks for Embedded Networks*, Final Report, 20 June 2019.
7 AER (2019) F*inal Decision – Ausgrid Distribution Determination 2019 to 2024, Attachment 18 Tariff Structure Statement*, April 2019, p 219.
8 AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, p xi

The AEMC recommendation links the ‘shadow price’ network charges for on-market child customers to our network tariffs for similar customers. As demonstrated in our analysis in section B.2, this linkage brings into prominence the network tariff arbitrage that until now was a salient feature of many EN business models. The AEMC report states that:

> “The Commission recognised that this approach could allow ENSPs to arbitrage the network tariff. However, the Commission considered that the benefits of using shadow network tariffs outweighed any concerns regarding ENSPs 'over-recovering' network charges from on-market customers”.[9]

AEMC report offers protection to end users within ENs

We agree that from the within-EN’s customer perspective, the AEMC approach provides a balanced solution. It is also the case that end customers outside ENs (that is, our network customers) are already protected by the provisions of the National Energy Retail Law (NERL). Both protections apply at retail level. Consideration of broader distributional effects of ENs on network charges for all network customers was outside the scope of the AEMC’s review.

Our proposed amendment is driven by our concern about the impact of EN growth on our existing customer base. We argue that ENs should share equitably in funding efficient network costs. Currently this is not the case, as demonstrated by our analysis presented in section B.2.

AEMC report defines exemptions from transition

AEMC’s final report proposes a scope and outcome of the transitional framework for existing ENs to comply with the proposed new regulatory requirements.

AEMC decided to exclude those legacy ENs subject to deemed and individual exemptions from the transitional framework.[10] Current deemed exemption classes are provided in AER’s registration exemption guidelines (March 2018).[11]

The transitional framework will apply to all legacy ENs that have registrable exemptions, according to one of three possible pathways:

- **Full transition** to the new framework for ENs established:
    - from 1 January 2020 to the *effective date* – within 9 months of the effective date
    - from 1 December 2017 to 31 December 2019 - within 2 years of the effective date of the new framework.
- **Partial transition** for the legacy ENs established prior to 1 December 2017, to be required to comply with the arrangements for off-market retailers, exempt from the metering provisions; required to comply with the AER’s pricing schedule; have network exemptions grandfathered into the new arrangements.
- **Individual exemption** from having to register as an ENSP and seek authorisation by the AER as an off-market retailer, can be sought by legacy ENs. If granted, such networks do not need to transition.

Effective date of the new regulatory requirements is the first anniversary of the commencement day. Estimated commencement day is 1 July 2020, and effective date 1 July 2021.[12]

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[9] AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, p 138.

[10] AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, pp 210-213.

[11] AER (2018), *Electricity Network Service Provider - Registration Exemption Guideline,* Version 6, March 2018, pp 29-31.

[12] AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, pp 210-213.

The AER will be required to make the initial AER Exempt Network Guidelines which prescribe the classes of persons who are eligible to register a network exemption under the revised Chapter 2 of the NER, to come into effect one year after the commencement day.

We propose to limit application of the new EN tariff to those ENs that are not exempt under the new framework.

The growth of ENs has accelerated

The number of ENs within the Ausgrid network is growing. We provide supporting evidence in section B.2.

The accelerated growth of ENs prompted us to seek the amendment to the TSS as it is not in the long-term interests of customers under current tariffs:

- Many ENs have been driven by arbitrage between residential and non-residential network tariffs and not by efficient competition to service end customers. The arbitrage opportunities under our approved TSS are illustrated in section B.2.
- By absorbing the growth in residential and small business customer numbers, while taking advantage of a tariff arbitrage, ENs do not share equitably with the broader customers base in funding network costs. If EN growth continues at its recent pace, forecast customer numbers will not materialise. This would mean that current indicative prices for residential and small business customers are set too low and would need to increase in the following year.
- Maintaining the current pricing is not in the long-term interests of the broader customer base who carry the higher share of residual costs after the establishment of ENs. This is especially the case for legacy flat tariffs with large customer numbers. From 1 July 2019, our new residential and small business customers are assigned to a default demand tariff – a key feature of our tariff reform. Customers within ENs are not exposed to comparable network price signals.

AER rejected our placeholder tariff in April 2019

The AER's final decision on our Revised TSS was to remove Ausgrid's proposed 'placeholder' tariffs that do not specify the tariff structure or an approach to annual pricing. [13] In our revised TSS (January 2019) we proposed a placeholder tariff EA333 *Embedded network* in anticipation of the AEMC introducing new regulatory arrangements for ENs. The AER considered that the undefined tariffs (ie, tariffs without tariff structures or indicative tariff levels) were not consistent with the Rules, because customers cannot understand undefined tariff structures, as the charging components are unknown (cl 6.18.5(i)). It was also not possible to assess whether the placeholder tariffs contribute to greater cost reflectivity or what impact they will have on customers (cl 6.18.5(d)).

This proposed amendment to the TSS contains the tariff structure and indicative levels for the tariff that was not approved as an undefined placeholder tariff in April 2019. The amendment is limited to one targeted intervention to ensure that our approved TSS 2019-24 tariff structures and price paths for the remainder of the regulatory period remain on track. This ensures tariff certainty for the vast majority of our customers for the remainder of the period.

What is our proposed amendment?

In our amendment to the TSS, our guiding principles and objectives for pricing are unchanged. Our overarching principle for pricing reform is to reduce customers' bills by lowering whole of system costs and make sure that our network costs are shared fairly between our customers. Our

[13] AER F*inal Decision – Ausgrid Distribution Determination 2019 to 2024, Attachment 18 Tariff Structure Statement*, April 2019, p 219.

analysis shows that our revised approach meets the National Electricity Rules and balances objectives.

Our proposed amendment is targeted and limited

In our amendment, we are seeking a targeted change by proposing new EN tariffs as a default assignment for new ENs energised after 1 July 2020, or existing ENs upgrading or modifying their connection after 1 July 2020, unless exempt under the AER Exemption Guidelines valid at that time of energisation or connection change.

We consulted on a secondary tariff as a fixed charge

At our Customer Forum on 17 September 2019, we consulted on a secondary EN tariff that took form of a fixed charge. For example, for Low Voltage ENs, secondary tariff in 2020-21 would be a fixed daily charge of about:

- 30c per day per residential child connection
- $1 per day per small business child connection (<40MWh pa)
- $4 per day per medium child connection (40-160 MWh pa)
- $11 per day per large child connection (160-750 MWh pa).

The information on the number and types of child connections would be updated annually and used as the basis for the secondary tariff for the following year. We would require ENs to report this information to us. If an EN failed to provide us with the data on the count and types of child connections, we would estimate them based on the best available information and use as a basis for charging during the year. These numbers would be submitted to the AER as part of the annual pricing proposal.

We calculated the indicative prices for the remainder of the 2019-24 regulatory period for ENs in Low Voltage, High Voltage and Sub-transmission classes (see section B.4).

We received stakeholder comments opposing the shape and form of the tariff. Stakeholders argued that a demand based charge would be more cost reflective rewarding ENs for their additional actions to reduce peak demand. Stakeholders also commented on the administrative difficulty in applying the tariff based on the number of child connections by connection type.

In response to stakeholders' comments we converted the secondary tariff we consulted on into a primary tariff that raises the equivalent amount of revenue by a mark-up on the capacity charge (see section B.4). This is the tariff that constitutes our proposed amendment to the TSS for the remainder of the 2019-24 regulatory period.

Our approach is effectively a modified 'retail-minus' approach by IPART

The secondary tariff we consulted on was based on a modified 'retail-minus' approach. The 'retail-minus' approach was used in the 2017 wholesale price review by the NSW Independent Pricing and Regulatory Tribunal (IPART) for Sydney Water and Hunter Water. [14] It is consistent with the efficient component pricing rule (ECPR) that encourages efficient entry into downstream market. IPART found that only a 'retail minus' approach is compatible with postage stamp price regulation.

Applying IPART's methodology to electricity distribution services, the 'retail minus' approach would be based on network tariffs to end-users as if they were directly connected to the Ausgrid distribution system (these are 'shadow prices' in the AEMC's 2019 final report). The 'minus' component of retail-minus prices reflect the costs a reasonably efficient competitor would incur in performing local reticulation services for their end-use customers (ie, the services from the point of

[14] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017.

wholesale purchase to end-use customers). Tariffs set at this level would encourage efficient entry into the local reticulation services market.

While providing an efficient price signal for new entry, the ‘retail-minus’ approach is not implementable in our case due to data limitations. DNSPs do not have visibility of child connection consumption behind the parent meter. If this changes in future (eg, if DSNPs provide a billing function to enable child connections to go on-market, or if access to on-market child consumption data is provided by other means), a full ‘retail-minus’ approach would be possible.

The ‘second-best’ tariff we consulted on relied on more readily available information. It removes most of the arbitrage on fixed charges and allows the savings on aggregated energy consumption and diversified demand to be retained by ENs and their customers. It is easy to understand (cl 6.18.5(h)(3)). This secondary tariff would minimise distortions to price signals for efficient usage, by taking the form of a fixed charge not affecting the peak price signal (cl 6.18.5(g)(3)).

When presenting this tariff to our customer forum, we argued that this ‘second-best’ approach would strike an appropriate balance between providing certainty of tariff structure and price levels to the vast majority of our customers while addressing the inefficiency of network cost allocation to C&I tariffs due to ENs, for the remainder of this regulatory period.

We received stakeholder comments opposing the fixed charge secondary EN tariff and supporting development of a primary EN tariff that realigns the demand charge for ENs to reflect the difference in the nature and extent of their usage, the nature of their network connection, and their load profiles (cl 6.18.4).

We have converted the secondary EN tariff we consulted on, into a primary tariff that applies to customers whose nature of use is to on-supply to their end customers. We changed our tariff assignment rules to reflect this. We explain our rationale for the tariff and its calculation in section B.4.

Who is affected by our proposed amendment, and how?

The AEMC’s proposed regulatory changes pave the way for us to address distributional effects of ENs in our distribution areas while managing the impact on within-EN customers.

Customers that are affected by our proposal are EN operators and their (within-EN) customers, and our wider customer base. Our wider customer base benefits from the proposed new tariff, as our customers will pay a smaller, and fairer, share of total efficient costs as a result of the proposal. The proposed tariff will reduce cross-subsidies from the wider customer base to ENs (see section B.6 on customer impacts).

New ENs energised after 1 July 2020 will have made their business decision with the knowledge of the tariff that would apply to them. They would also have built into their business model additional compliance costs associated with the AEMC’s proposed updated regulatory framework.

There is no impact on existing ENs on 1 July 2020. Existing ENs will be impacted when they upgrade or modify their connection after 1 July 2020. We propose to manage these impacts by grandfathering legacy exempt ENs from the EN tariff until they modify or upgrade their connection, and then align exemption criteria with those set by the AER’s guidelines applicable at the time of the connection change.

Within-EN customers will be protected by retail competition that the updated regulatory framework entails. End users within legacy ENs will be protected via grandfathering of exempt legacy ENs. In making this proposal we address the concerns of our customer advocates regarding vulnerable customers (such as caravan parks) that might be affected by our proposed changes unless protected by access to retail competition or retail price regulation by the AER. We limit application of the new EN tariffs to customers with consumption above 160 MWh pa, so that small legacy ENs such as caravan parks are not affected by this proposal.

We estimate that our proposed secondary tariff, assuming grandfathering of existing legacy ENs, removes 20% of total cross-subsidy and delivers a benefit of $10 per customer per year by 2023-24. Our customer impact analysis is presented in section B.6.

How will the proposed amendment work and meet the Rules?

Our amended TSS would better comply with pricing principles for direct control services, because:

- Our tariffs become more efficient if the difference between ENs and C&I customers is recognised (cl 6.18.1B(b)(5)).
- It improves fairness of contribution to funding network costs, reduces cross-subsidies, and makes ENs contribute more equitably to postage stamp pricing and universal service obligations that we are required to deliver to our customers.
- It supports efficient competition in the EN market.

Our proposed EN tariffs contribute to improving efficiency of our C&I tariffs by having regard to the additional costs likely to be associated with meeting demand from EN customers at times of greatest utilisation of our network (cl 6.18.5(f)(2)). Our current C&I peak charging windows do not coincide with the time when residential and mixed residential ENs peak. Our proposed new EN tariff achieves more equitable recovery of residual costs by a mark-up on the C&I capacity charge.

For the remainder of the current regulatory period, our proposed amendment will ensure that revenue collected from C&I tariffs, supplemented with the revenue from the EN tariffs, when summed up with the revenue expected to the received from all other tariffs, permit us to recover our expected allowed revenue (cl 6.18.5(g)(2)).

We have engaged with EN customers, retailers and our customer advocates to develop the proposed amendment to the TSS, and modified our approach based on their feedback that strikes an acceptable balance (cl 6.18.1B(b)(6)).

Our amended TSS, these Explanatory Notes to the Amendment, and accompanying attachments together explain how our proposed amended TSS including the new EN tariffs meets the National Electricity Rules to ensure prices are cost reflective. Additional details are provided in section B.5.

When will the proposed amendment be implemented?

We propose to introduce the new EN tariffs from 1 July 2020, for newly energised ENs and for existing ENs upgrading or modifying their connection (unless exempt under the AER's exemption guidelines applicable at the time).

Because the charging parameters and charging windows of the proposed new EN tariffs are identical to those of our existing C&I tariffs, changes to the billing systems should be manageable within the remaining time to 1 July 2020. We will engage with retailers early on the proposed new tariffs and their implementation.

What happens next?

We recognise that introducing the default EN tariffs is a substantial change for EN operators, their retailers and potentially their customers which requires a comprehensive communication campaign from all stakeholders. Our proposed tariffs support our broader tariff reform towards cost reflective pricing.

Following receipt, the AER is required to publish this Amendment on its website. We expect that the AER will consult on our Amendment prior to making a decision on our Amendment by the end of February 2020.

The timing of the AER's final decision by end of February 2020 will enable us to build and communicate the new EN tariffs to be applied from 1 July 2020. We will be working closely with retailers to enable application of the new tariffs.

We are continuing to work with customer advocates including the Energy and Water Ombudsman of NSW and our Pricing Working Group to support communication of our tariff reform which includes these proposed EN tariffs. We are working with retailers on the implementation of the proposed new tariffs. We are discussing our proposal and common network challenges with our fellow distributors in NSW, Endeavour Energy and Essential Energy.

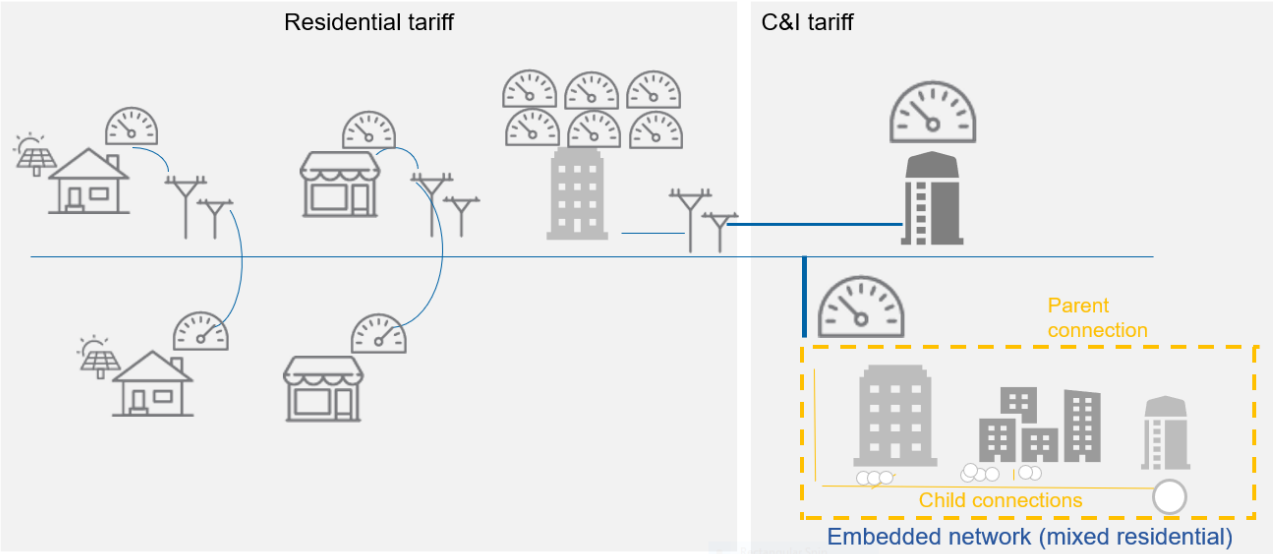
B.2 Our network and our customers

This section provides additional information on ENs in our distribution area, and their impact on our broader customer base.

Growth of ENs in our distribution area

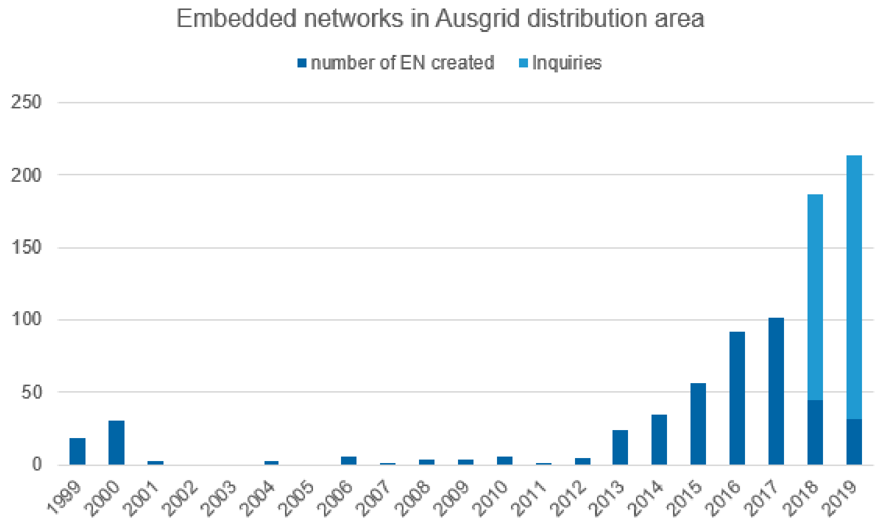
ENs are private electricity networks that serve multiple customers and are connected to another distribution or transmission system in the national grid through a parent connection point. A schematic representation of an EN connection to our network is presented in Figure B2.1.

Figure B2.1. Tariff treatment of embedded networks in our distribution area



As of June 2019, there were about 420 known ENs in our distribution area. The number of new EN inquiries increased from 1 per month prior to 2016 to 12 applications per month in 2017-18 and 15 applications per month in 2018-19 (see Figure B2.2).

Figure B2.2. Number of ENs and new EN applications to Ausgrid

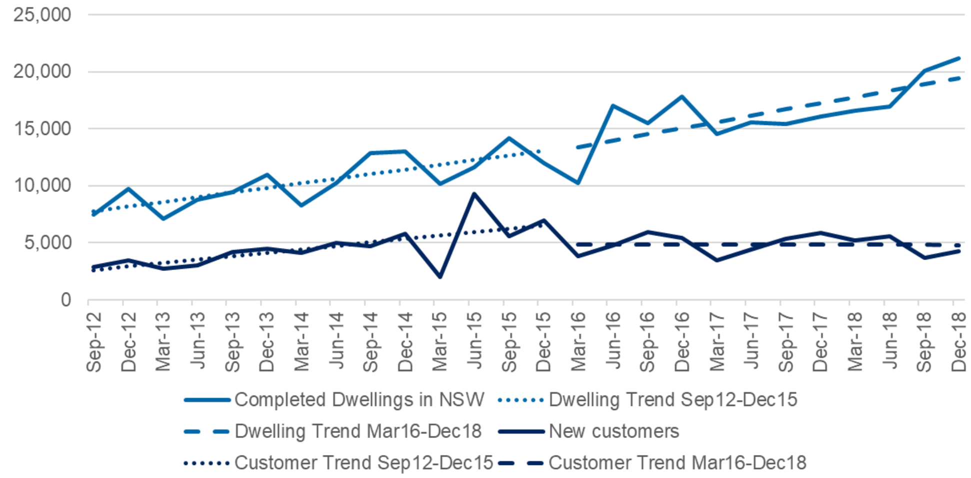


Based on the current regulatory settings and connection application rates, we expect the number of ENs to continue to increase over time.

The acceleration of EN formation in our distribution area coincided with a period of urban development, and an increasing share of apartments in multi-storey buildings.

The recent period of urban growth was not matched by comparable growth in our customer numbers. Our forecast of future residential customer numbers is based on the model that links the new customer numbers to dwelling completions. However, this nexus has weakened. By December 2018, the gap between our actual cumulative new customer numbers and forecast numbers based on the trend in new dwellings in our distribution area has grown to an estimated 44,000 customers (see Figure B2.3).

Figure B2.3. Trends in the number of new Ausgrid customers vs NSW completed dwellings



At the same time, ‘residential’ ENs as a share of the total number of ENs established and operating in our distribution area increased from about 9% in June 2015 to 53% in June 2019. This corresponds to a 23-fold increase in residential EN numbers, from 10 to 225 over the corresponding period. More than 80% of the new ENs created since January 2018 are residential.

We substantially adjusted forecast new customer numbers down between our initial Regulatory Proposal in April 2018, Revised Proposal in January 2019, and the Initial Pricing Proposal in April 2019. Sustained EN growth will require further adjustments over the 2019-24 regulatory period.

2019. Sustained EN growth will require further adjustments over the 2019-24 regulatory period.

The shift of forecast customers from residential to ENs would not be a problem if there was no tariff arbitrage and these two groups contributed equally to network costs. As it stands, if the prices for residential tariffs were set too low based on overly optimistic new residential customer numbers, all other things being equal, there would be an under-recovery of revenue from these customers during the year. This revenue shortfall would then be added to the revenue to be recovered from the customers the following year, pushing residential prices up. There would also be within year cashflow implications unless the shortfall of revenue from residential tariffs was offset by increased revenue from C&I tariffs, due to EN growth in the C&I category. However, as our analysis in the later sections demonstrates, the additional revenue from higher than forecast EN customers is insufficient to offset the loss of residential tariff revenue. Similar reasoning applies to the small business customer category. As a result, our existing residential and small business customers, especially those on legacy flat tariffs, effectively provide a subsidy to ENs.

Current default assignment of ENs is to C&I tariffs

Our default tariff assignment for ENs is based on the nature of connection (connection voltage) that defines the tariff class – Low Voltage (LV), High Voltage (HV) or Sub-transmission (ST). Within the LV class, new ENs are assigned to an appropriate non-residential tariff based on the extent of network usage (expected annual consumption).[15]

Most of the recently created ENs are in the large Low Voltage (LV) class, predominantly on LV large customer tariffs EA310 (>750 MWh pa), followed by EA305 (160-750 MWh pa). High Voltage ENs, while representing a substantial share based on consumption, have been growing at a slower pace (see Figure B2.4).

Figure B2.4. Energy consumption by ENs by tariff type

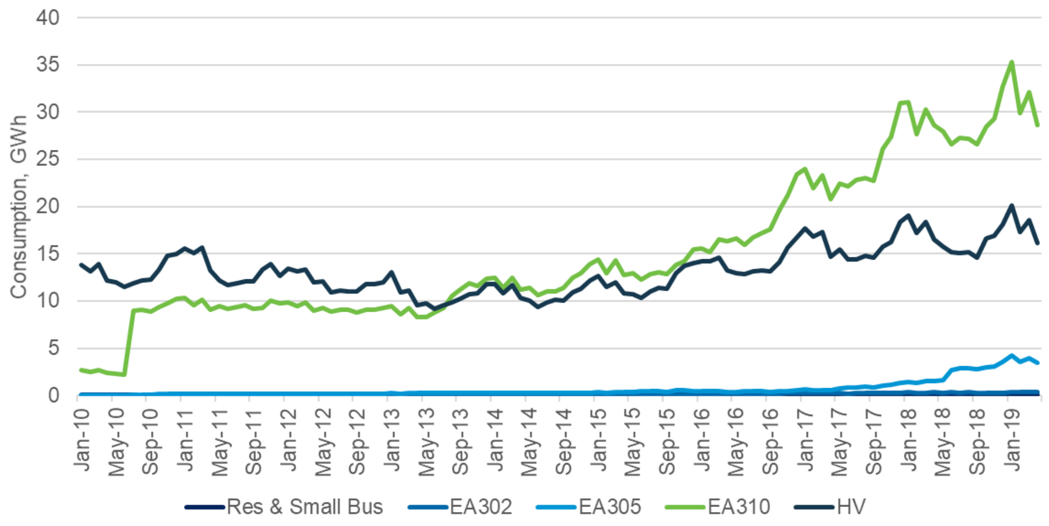
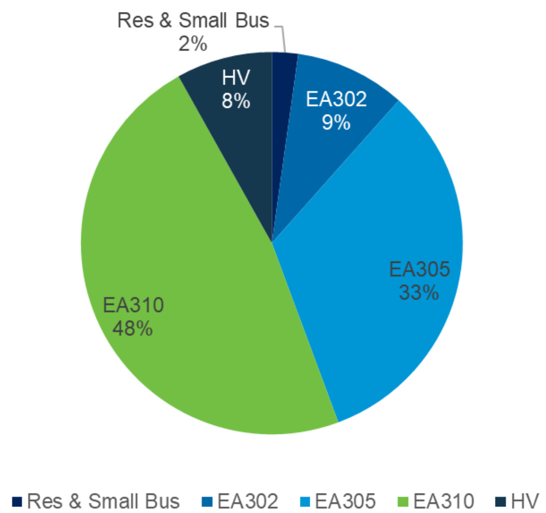


Figure B2.5. Number of ENs by tariff type



LV ENs lead also in terms of customer numbers (50% of our current ENs are LV EA310 (>750 MWh pa) and 31% are LV EA305 (160-750 MWh pa) customers (see Figure B2.5).

[15] Tariff Structure Statement 2019-24, Figure 2.2, p 8.

ENs load profiles are different from an average C&I customer

We analysed the load profiles of our known EN customers and established that their load profiles differ significantly from the load profile of a typical C&I customer. A profile of our average LV EA310 (>750 MWh pa) customer was compared with the average profile of a LV EN, classified as either 'residential' or 'non-residential'. We classified an EN as 'residential' if it represented mostly a collection of residential apartments or units. Note that a C&I tariff applies to 'residential' EN parent connections.

In summary,

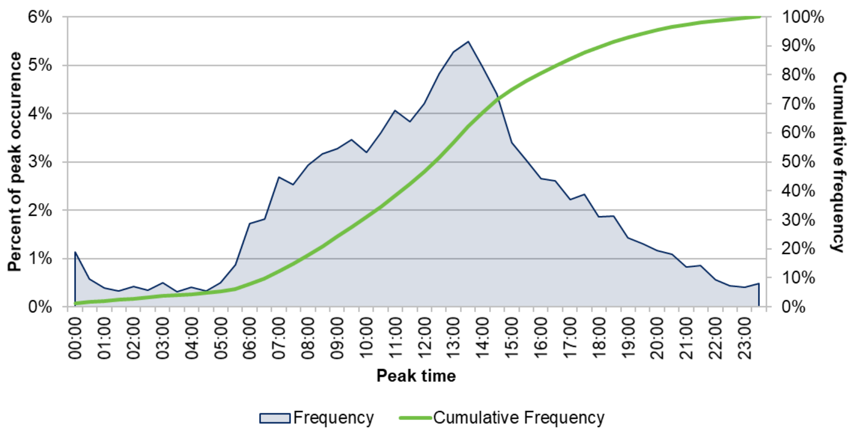
- Residential ENs demonstrate evening hours peak consistent with the typical residential load, are smaller than the average C&I and are more diverse (Figures B2.6 and B2.7)
- Non-residential ENs are more concentrated than an average C&I customer, are larger and less diverse (that is, displaying more concentrated distribution of the daily peaks, or peaking at about same time) (Figures B2.6 and B2.8)
- Distribution of peak demand periods is also different between ENs and C&I customers. Relative to C&I customers ENs:
    - peak in the evening hours outside the non-residential (C&I) peak window of 2-8 pm for residential ENs (Figure B2.9), and
    - exhibit a higher share of load in the peak window for non-residential ENs (Figure B2.10).

Analysis for HV tariff class is presented in Figures B2.11 - B2.13.

Analysis for ST tariff class is presented in Figures B2.14 - B2.16.

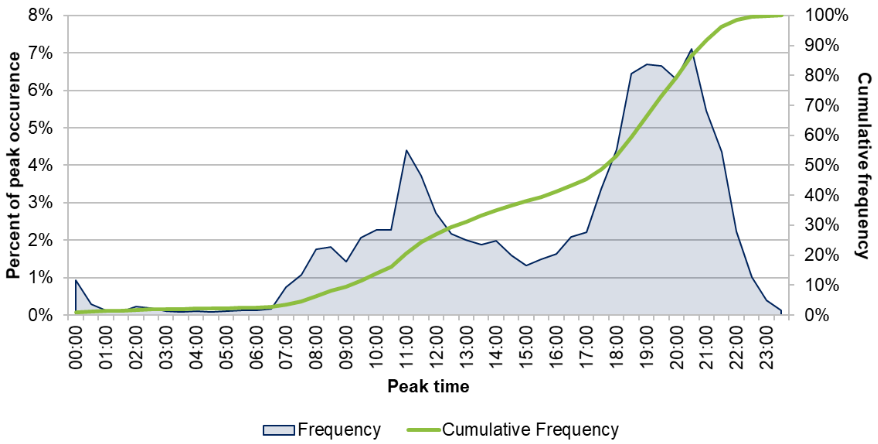
In both cases, the load profile of an EN is significantly different from the substantially flat profiles of the HV and ST customers, with incidence of later hours peaks not captured by our non-residential peak charging windows of 2-8 pm. One of the implications of this finding is that ENs do not respond to time of use (TOU) price signals in the way other C&I customers do.

Figure B2.6. Distribution of daily peaks of LV C&I (EA310) customers



Residential ENs demonstrate a clear residential peak, are smaller than the average C&I and are more diverse (see Figure B2.7).

Figure B2.7. Distribution of daily peaks of LV residential EN customers



Large non-res EN are more concentrated than the average C&I customer, larger and less diverse (see Figure B2.8). The pattern repeats for HV and ST ENs.

Figure B2.8. Distribution of daily peaks of LV non-residential EN customers

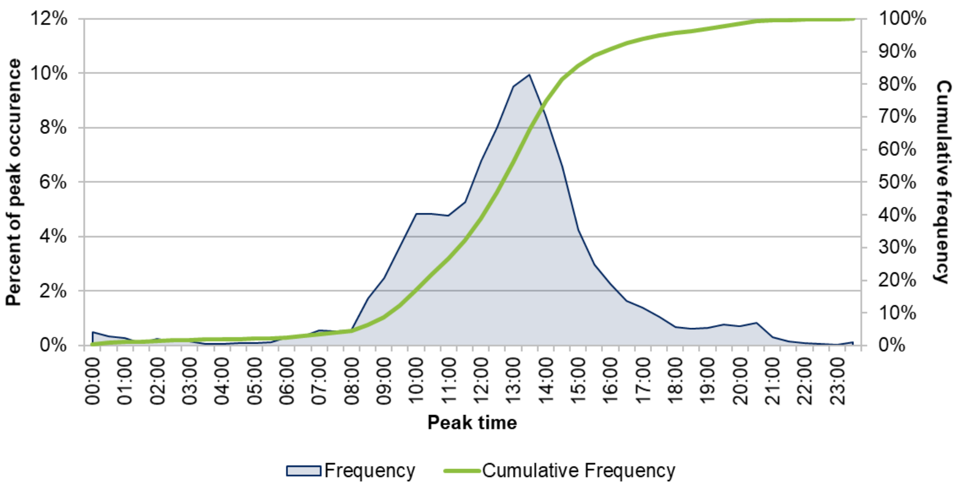


Figure B2.9. Daily demand pattern for LV residential EN vs average LV C&I customer

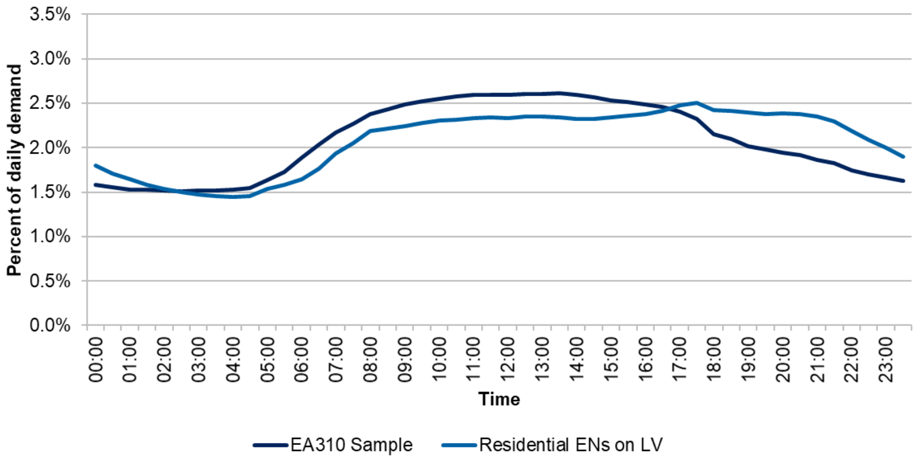


Figure B2.10. Daily demand pattern for LV non-residential EN vs average C&I customer

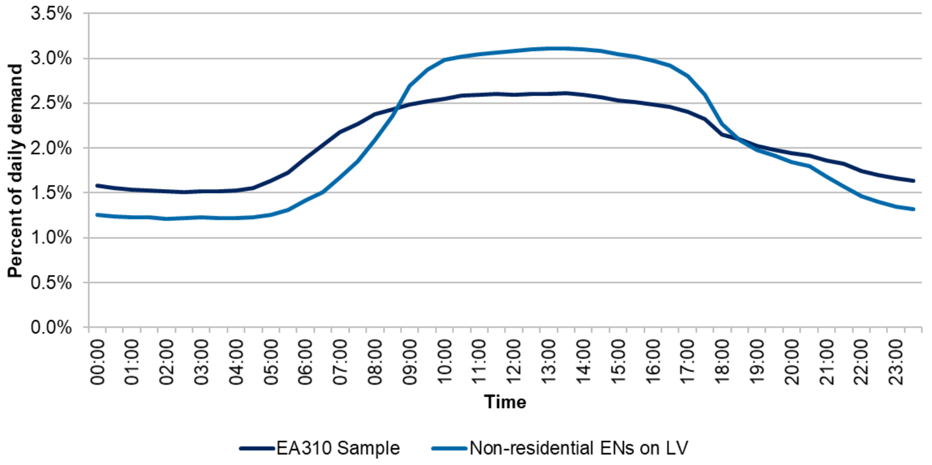


Figure B2.11. Distribution of daily peaks of HV C&I customers

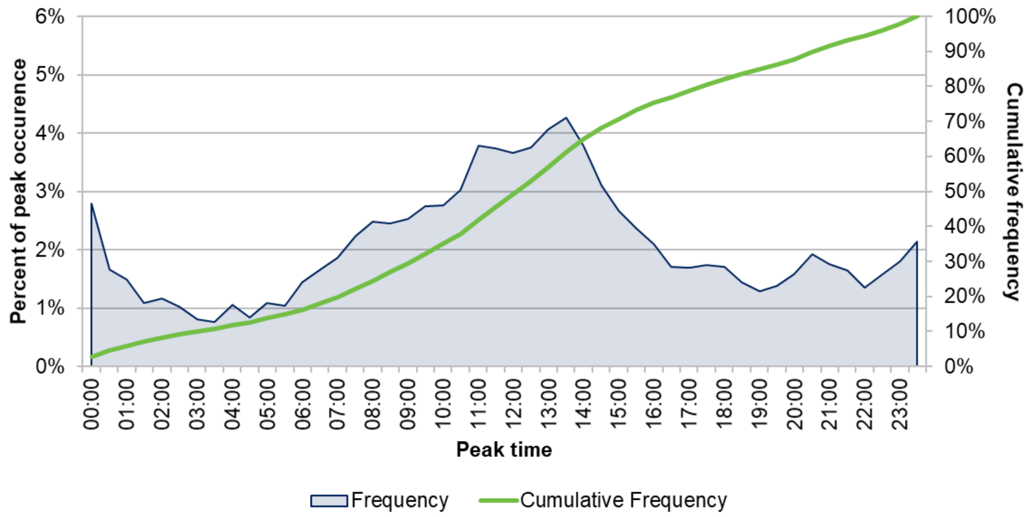


Figure B2.12. Distribution of daily peaks of a sample HV mixed residential EN

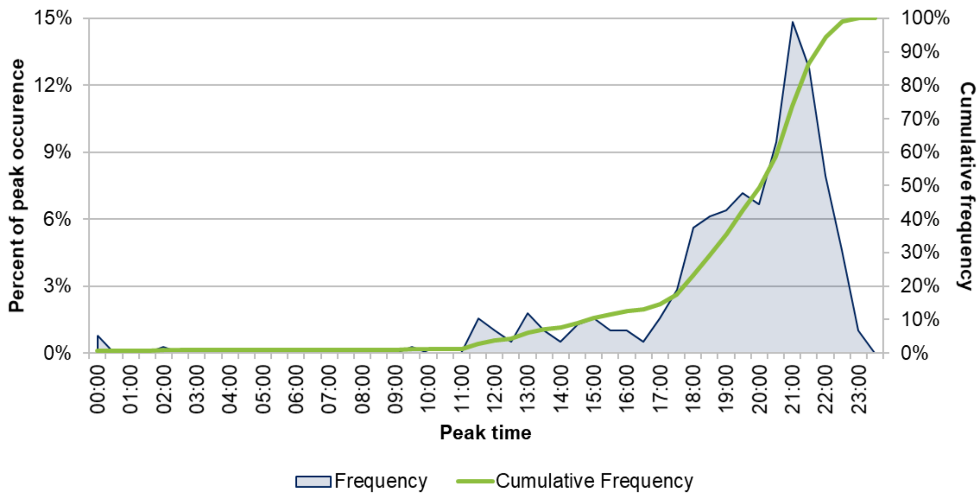


Figure B2.13. Daily demand pattern for a sample HV mixed residential EN vs HV C&I

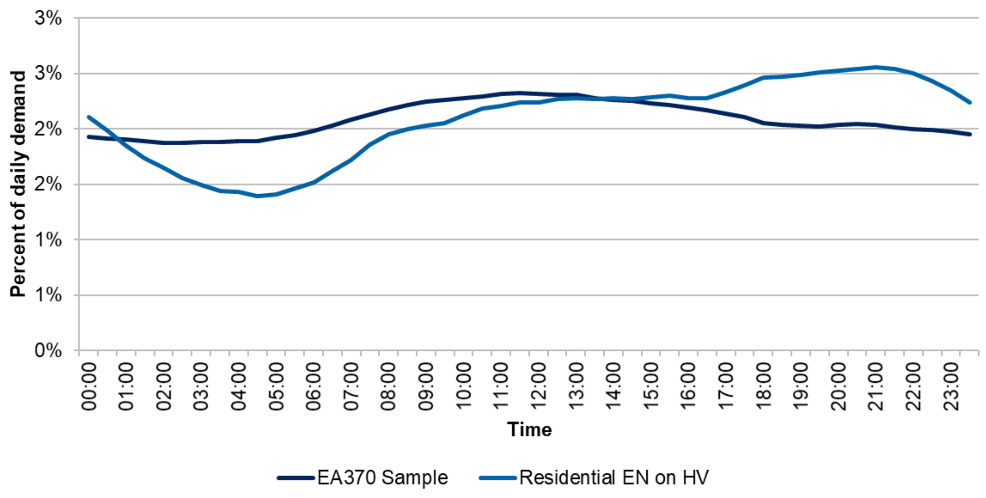


Figure B2.14. Distribution of daily peaks of ST C&I customers

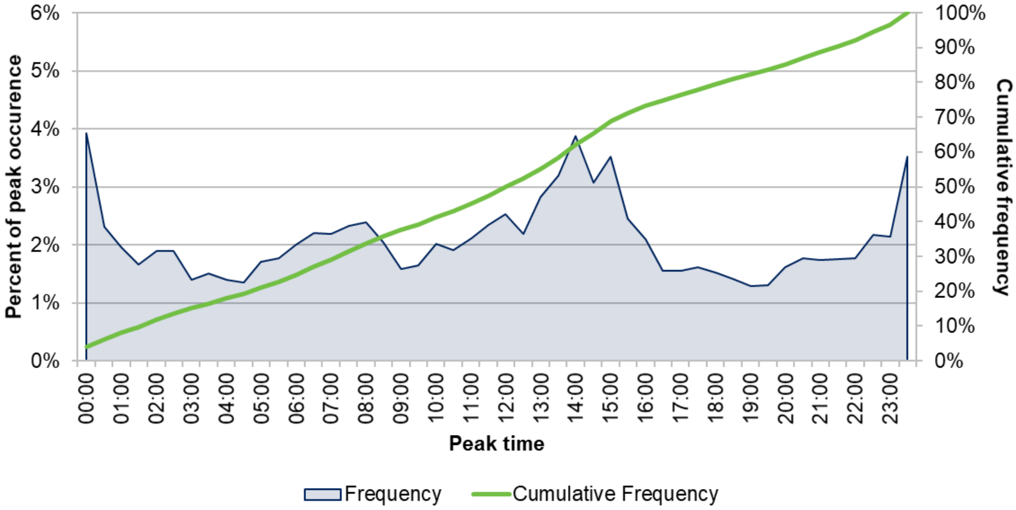


Figure B2.15. Distribution of daily peaks of a sample ST mixed residential EN

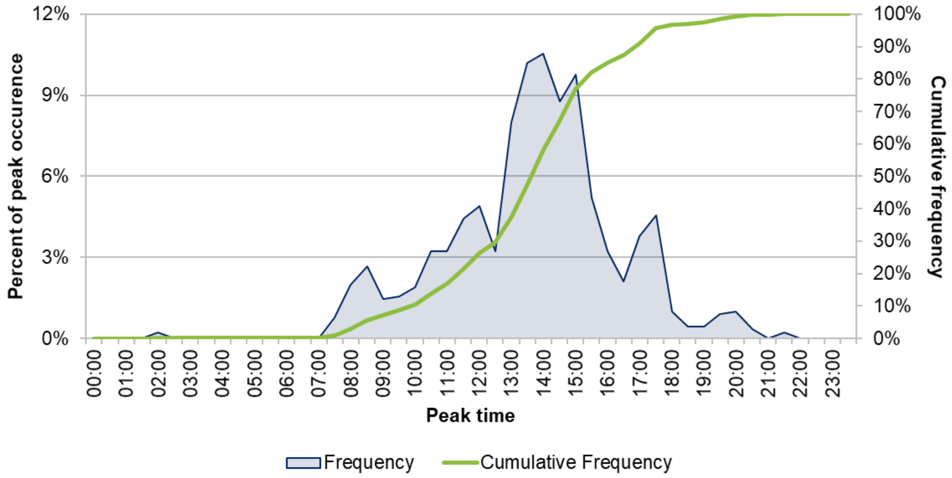
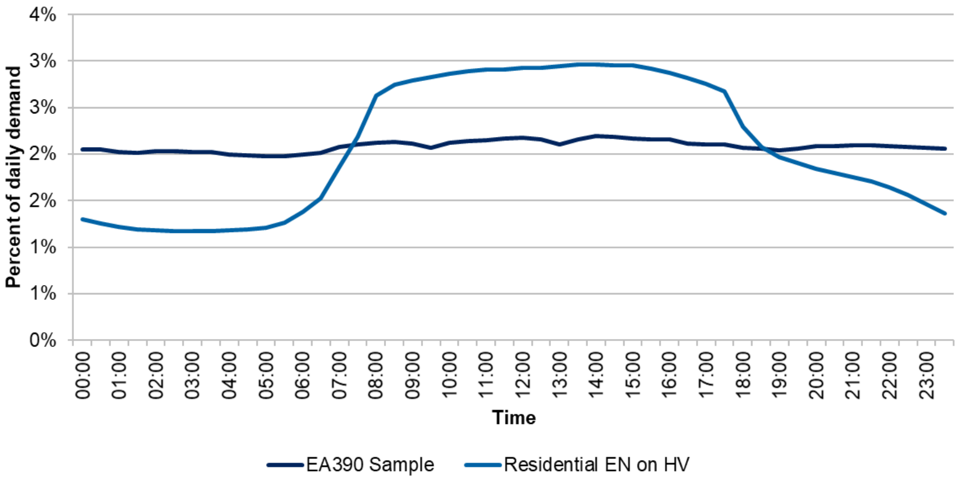


Figure B2.16. Daily demand pattern for a sample ST mixed residential EN vs ST C&I



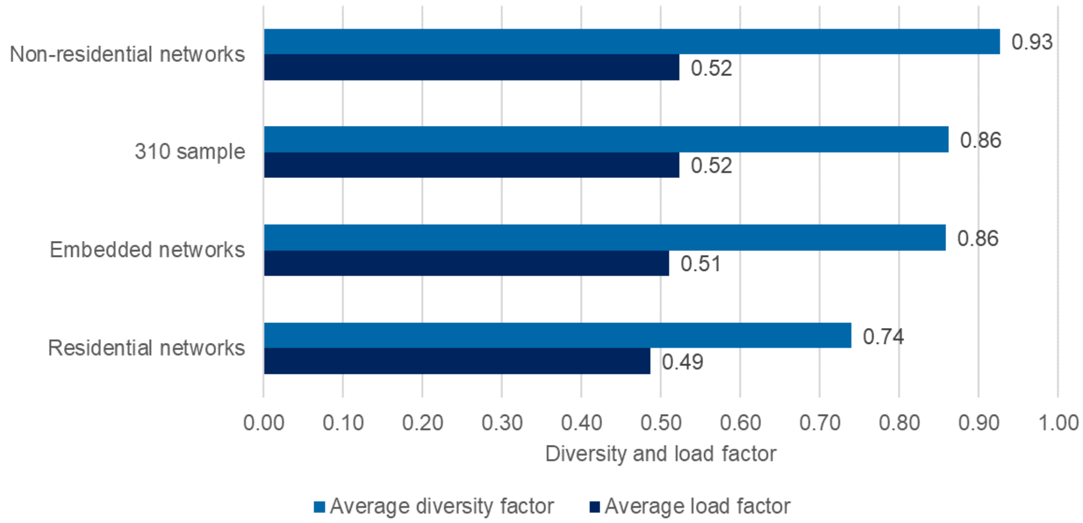
ENs' load and diversity factors are different

The randomness of individual peak timing during the day ensures a smoother aggregate demand peak, as everyone is peaking at a different time and not necessarily at the time of the network peak. This diversity of use and behaviours is the cornerstone of network planning which allows us to size our network to accommodate the growth in aggregate demand rather than individual demand. Diversity is a benefit to all our customers. Even if the same cost-reflective (eg residential demand) tariff applied to the aggregated profile of residential customers, the total charge for the collection of these customers would be lower than the sum of individual residential charges, due to the diversity of individual uses resulting in lower peak demand of the aggregate compared to the sum of individual peak demands.

ENs capture the benefits of diversity without necessarily reducing individual peak demands. Our residential and small business customers are as a result denied the full benefits of the tariff reform that introduced default demand tariffs, to make the whole group of tariffs more cost reflective. Within-EN customers do not necessarily receive cost reflective price signals, hence our tariff reform would not be as effective as envisaged under our original new customer forecasts.

Residential ENs have a lower load factor and are more diverse than the average C&I customer.[16] Non-residential ENs differ from an average C&I customer in presenting a much lower diversity factor and being of a significantly larger size. (see Figure B2.17).

Figure B2.17. Average diversity factor[a] and load factor[b] for LV EN and C&I customers



Note: [a]Diversity factor is defined as the customer's demand at the time of system peak, as a proportion of own peak demand. The higher diversity factor, the more likely the customer's peak is close in time with the system peak. The higher the average diversity factor, the less diverse the group of customers is, with more customers peaking at around the system peak time. [b]Load factor is the ratio of average demand to maximum demand.

If ENs remain within the C&I tariff, the net effect on this tariff's share in peak demand and the average load factor would depend on the relative mix of residential vs commercial EN in the future growth.

- If commercial ENs prevail, the overall diversity factor of C&I tariff customers will increase (that is, customers would appear to be increasingly more like each other at the time of system peak). This would make the C&I tariff customers' contribution to future augmentation costs higher. To remain cost reflective, the prices for all C&I customers would need to increase.

[16] We based the LV analysis on a sample of EA310 (>750 MWh) C&I customers.

- If residential ENs prevail, this would reduce overall diversity of the C&I tariff, making it seemingly overpriced for other C&I customers. Prices for other customers (eg, residential) would need to increase.

By differentiating ENs from the C&I tariff, the EN tariff improves overall efficiency of our tariffs and their compliance with the pricing principles recognising customers with systemic difference in their load profiles (cl 6.18.1B(b)(5)).

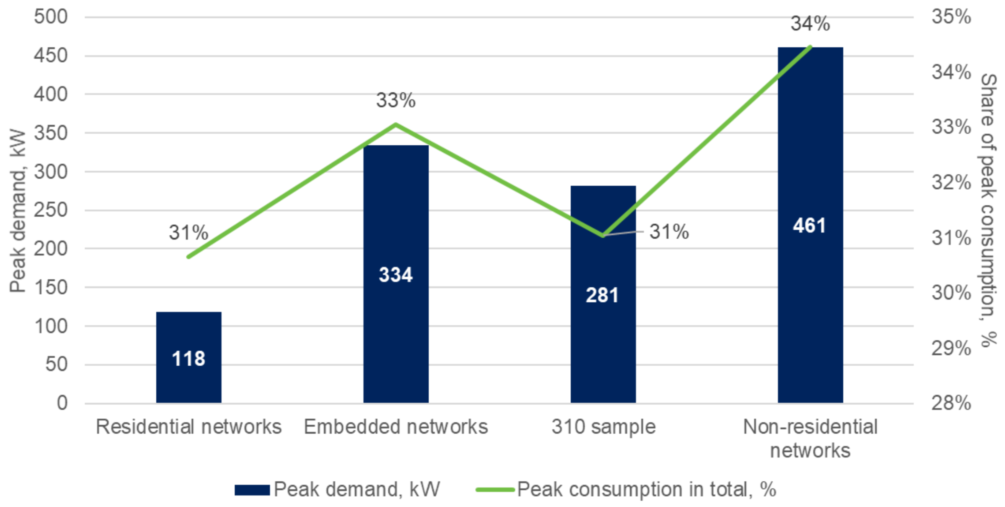
ENs are different in the size and shape of their peak

Non-residential ENs have a higher share of consumption in the peak hours compared to the C&I group (see Figure B2.18). Their peak consumption and peak demand drive the cost for the whole tariff up, because our methodology determines the revenue share payable by a tariff on the basis of its contribution to network peak demands and total energy use.

By consuming proportionately less in peak billing periods, residential ENs are not paying their fair share, as their peak hours fit better with residential peak hours. Note winter peak hours for residential customers are 5-9 pm. Residential ENs' capacity is measured based on a 2-8 pm charging window throughout the year. As such, any peaks between 8-9 pm are not priced.

By differentiating EN from the LV C&I tariff we are guided by clause 6.18.4 of the NER that retail customers with a similar connection and usage profile should be treated on an equal basis when assigning or re-assigning customers to tariff classes.

Figure B2.18. Peak demand and peak period consumption for LV EN and C&I customers



Current tariffs provide arbitrage opportunities

ENs aggregate residential and small business loads, allowing the savings on aggregated fixed daily charges, energy consumption and diversified demand to be retained within the EN.

We estimate that the current (2019-20) impact of ENs on our existing customers is about $29 per customer per year (see section B.6). The impact represents the arbitrage between residential/small business individual tariffs and the C&I tariffs for the aggregated load if these customers are removed from our customer base.

Due to the unavailability of within-EN child consumption data, we created synthetic examples of ENs using actual data of our direct customers in settings that can be configured as an EN. We applied our current 2019-20 network prices to calculate and compare network bills under two scenarios: direct individual connection to our network, and a total bill for an EN comprised of these child connections. We modelled residential, commercial and mixed ENs:

- residential EN was modelled by aggregating a set of existing residential NMIs into an EN (arbitrage of $61,000 or 46% of network charges, see Box B2.1)
- commercial (non-residential) ENs are modelled in two configurations of different sizes (arbitrage of $40,000 or 23%, and $25,000 or 31% of network charges, see Box B2.2)
- mixed residential is modelled by aggregating a set of existing residential and non-residential NMIs into a single EN (arbitrage of $74,000 or 42% of network charges, see Box B2.3).

These examples illustrate there is a clear tariff arbitrage incentive to establish an EN. This incentive is particularly significant for residential ENs. Our worked example shows that the C&I tariff that applies to a collection of 315 residential customers in a single EN is 46% lower than the sum of individual network charges, generating an arbitrage of about $61,000 (or $190 per within-EN customer) per year.

Residential ENs in the LV class eliminate almost none of our costs (see section B.4). By not contributing equitably to our network costs, ENs push costs onto our wider customer base. Current pricing arrangements for ENs are not in the long-term interest of our customers who would carry a higher share of residual costs after the establishment of ENs.

To address the recent growth in the EN formation within our distribution area, we are proposing a default tariff for ENs to ensure that the cross-subsidy does not grow and our indicative prices in the approved TSS and the initial pricing proposal remain on track.

We have consulted with our customers when preparing this amendment to the TSS. Section B.3 outlines our customer consultation.

Box B2.1. Analysis of revenue impact from EN – residential

Modelling inputs

Interval data for 315 NMIs of residents in an apartment block each on a TOU network tariff.

The what if scenario

Total Network Use of System charges for the 315 individual NMIs on the 2019-20 seasonal TOU tariff (EA025) vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff.

Comparison of Network Use of System revenue, 2019-20

Embedded network:315 NMIs	Individual NMIs in Ausgrid Network (EA025 TOU)	Individual NMIs in EN (EA310)
Consumption per NMI	3,268 kWh	
Total consumption	1,029,409 kWh	
Fixed – network access charges	$52,934	$9,106
Energy consumption charge (kWh)	$72,506	$19,082
Demand/capacity charge (kVA)	-	$36,161
Secondary EN charge	-	-
Total network bill pa	**$125,441**	**$64,349**
Difference ($)		**-$61,092**
Difference (%)		**-46%**

Box B2.2. Analysis of revenue impact from EN– two businesses

Modelling inputs

Data from NMIs on a mix of tariffs using two business examples: two buildings likely to be a business centre with many offices.

The what if scenario

Total Network Use of System charges for the individual NMIs on their 2019-20 tariff vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff.

Comparison of Network Use of System revenue, 2019-20

Embedded network A: 13 NMIs on 4 different tariffs	Individual NMIs in Ausgrid Network (EA225, EA302, EA305, EA316)	Individual NMIs in EN (EA310)
Consumption per NMI	147,014 kWh	
Total consumption	1,911,176 kWh	
Fixed – network access charges	$26,851	$9,10
Energy consumption charge (kWh)	$56,283	$37,78
Demand/capacity charge (kVA)	$91,459	$88,15
Secondary EN charge	-	
Total network bill pa	**$174,593**	**$135,04**
Difference ($)		**-$39,54**
Difference (%)		**-23%**

Embedded network B: 25 NMIs on 3 different tariffs	Individual NMIs in Ausgrid Network (EA050, EA225, EA302)	Individual NMIs in EN (EA310)
Consumption per NMI	30,387 kWh	
Total consumption	759,666 kWh	
Fixed – network access charges	$22,541	$9,10
Energy consumption charge (kWh)	$4,812	$14,74
Demand/capacity charge (kVA)	$13,787	$32,35
Secondary EN charge	-	
Total network bill pa	**$81,140**	**$56,20**
Difference ($)		**-$24,93**
Difference (%)		**-31%**

Box B2.3. Analysis of revenue impact from EN– mixed residential and non-residential

Modelling inputs

Data from NMIs on a mix of residential and non-residential tariffs – 315 residential NMIs on EA025 and 6 non-residential NMIs on EA025, EA225 and EA302.

The what if scenario

Total Network Use of System charges for the individual NMIs on their 2019-20 tariff vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff.

Comparison of Network Use of System revenue, 2019-20

Embedded network: 75 residential NMIs and 18 non-residential NMIs	Individual NMIs in Ausgrid Network (EA025, EA225, EA302)	Individual NMIs in EN (EA310)
Consumption per NMI	17,874 kWh	
Total consumption	1,662,272 kWh	
Fixed – network access charges	$58,447	$9,106
Energy consumption charge (kWh)	$110,061	$30,449
Demand/capacity charge (kVA)	$6,102	$61,109
Total network bill pa	**$174,611**	**$100,664**
Difference ($)		**-$73,947**
Difference (%)		**-42%**

B.3 Our customer consultation

Our process for customer consultation on pricing reform includes engaging our Customer Consultative Committee and Pricing Working Group. We have continued this engagement in preparing this amendment to the TSS.

Customer Consultative Committee

The Customer Consultative Committee is the main body we use to provide customer and external stakeholder perspectives on our plans, policies and service delivery, our regulatory submissions and the regulatory framework; and ensure appropriate and effective customer and stakeholder engagement. Box B3.1 lists the current members and observers.

Box B3.1. Customer Consultative Committee members and observers

- Council on the Ageing NSW
- Energy & Water Ombudsman NSW
- Energy Consumers Australia
- Ethnic Communities Council NSW
- Major Energy Users
- NSW Council of Social Services
- Public Interest Advocacy Centre
- St Vincent de Paul Society
- Total Environment Centre
- Consumer Challenge Panel (observer)

Pricing Working Group

Since the submission of our Initial Proposal in April 2018, we set up a Pricing Working Group to guide our pricing reforms. The Pricing Working Group helped us develop the pricing strategy in our TSS that fairly recovers the costs of providing network services, while also giving customers transparent price signals that enable them to benefit from more efficient use of the network. This strategy now includes demand tariffs for residential and small business customers, co-designed with customer advocates.

Members of the Pricing Working Group are:

- the AER Consumer Challenge Panel
- Energy Consumers Australia
- Energy Users Association Australia
- NSW Business Chamber
- Public Interest Advocacy Centre
- St Vincent de Paul Society, and
- Total Environment Centre.

EN Customer Forum

We engaged with retailers, industry and ENs customers at the Ausgrid EN Customer Forum on 17 September 2019. We received questions and comments from Lend Lease, Shopping Centre

Council, Flow Systems, UNSW, ECA, Pricing Working Group, WINConnect, Caravan and Camping Industry Association NSW, and retailers.

How we have responded to feedback

SSince the 17 September public forum, we have continued to engage with many stakeholders on our proposed EN tariff. Stakeholders have sent through questions and spoken to us on the phone about our plans.

Across all channels of engagement we received valuable feedback which has challenged, shaped and greatly improved our proposed EN tariffs.

In the short time since the public forum we worked intensively to address all the queries we received. We modified our proposal to introduce a primary EN tariff that applies a mark-up to a capacity charge, achieving the same outcome as the secondary tariff we consulted on, but at a lesser administrative cost.

The new tariff rewards ENs for their additional actions that reduce the peak demand which is the major driver of our future augmentation costs. At the same time, it recovers an equivalent amount of revenue to our secondary tariff. Importantly, our customers' feedback also led us to amend our proposed grandfathering arrangements.

How we have responded to stakeholder feedback is outlined in Table B3.1 below.

Table B3.1. Our response to stakeholder feedback on the proposed Amendment

Feedback from stakeholders	How we have responded
Grandfathering Customer advocates were generally opposed to the grandfathering of existing ENs from our EN tariff. EN operators, on the other hand, support grandfathering of existing ENs and a delayed implementation of our EN tariff.	We have modified our approach to grandfathering following stakeholder feedback. We included exemption provisions for the EN tariff to apply. Despite the views of our customer advocates, we support grandfathering existing ENs from the EN tariff until such time when they upgrade or modify their connection. We are also proposing to align exemption criteria with those set by the AER's guidelines applicable at the time. We considered stakeholder feedback that additional time would assist ENs transitioning to our EN tariff. We recognise the effect that the growth of ENs is having on our customers. Delaying this tariff is not in the long-term interest of our customers. We now propose to apply our primary EN tariffs from 1 July 2020, to newly energised ENs and existing ENs modifying or upgrading their connections, unless exempt under the AER guidelines at that time of energisation or connection change.
Cost reflective pricing At our public forum, stakeholders queried why the secondary EN tariff is needed if C&I are already 'cost reflective.'	In this document, we have explained how cost reflective prices incorporate both: - a signal to customers of future network costs that could be avoided (also known as long run marginal cost) and - a share of the efficient regulator approved costs of building the network (also known as residual costs) Based on their share of residual costs, load profile and loss of network diversity, this TSS Amendment explains how the C&I tariff paid by EN operators is not reflective of the costs they impose on the network. We converted the secondary tariffs we consulted on, into a primary EN tariff that is more cost reflective for these customers based on the nature of their usage It also rewards EN customers for reducing their peak demand.

Equity issues Stakeholders queried the equity of the secondary EN tariff if it will capture low consumption users in small dwellings	In this TSS Amendment we explain how our postage stamp pricing approach means similar customers are charged (through their retailer) the same network access charge and energy consumption charge. Under present arrangements, depending on whether they source their electricity from within or outside an EN, customers with identical consumption and usage profiles make different contributions to the overall cost of running the network. In our view, it is inequitable for a customer outside an EN to effectively be subsidising a customer within an EN. Our proposed primary EN tariffs address this inequity.
Vulnerable customers Stakeholders pointed out that customers within certain types of EN can be on lower-incomes	We have carefully considered whether the secondary EN tariff we consulted on would apply to all, or a subset of ENs. We recognise that: - not all ENs will be subject to the AEMC's new regulatory framework, with the AER exemption framework playing a role in determining which will be captured by the new arrangements and which will not, and - different pricing protections will apply to different types of ENs, with the *Residential (Land Lease) Communities Act* and *Holiday Parks (Long-term) Casual Occupation) Act 2002* providing consumer protections for residents of residential land lease communities and holiday parks. Consistent with the AEMC's new regulatory framework, we consulted on limiting application of the EN tariffs to those ENs that are not exempt under the new framework. We are now proposing a primary tariff that responds to stakeholder concerns. For the remainder of the 2019-24 regulatory period, the EN tariff will not apply to customers below a 160 MWh consumption threshold, where smaller unregistered ENs might be present. This measure offers a reasonable degree of protection to smaller ENs such as lifestyle villages, residential parks and residential land lease communities.
We consulted on how the secondary EN tariff would be charged	We considered that retailers would be charged the secondary EN tariff as a separate line item in addition to the EN's primary C&I tariff. The charge would be based on the total number of child connections (both on-market and off-market), by connection type. This number would be reported to us annually by the EN's retailer by 31 December. We received stakeholder feedback on the difficulties to implement the secondary tariff, especially to establish clear and transparent processes to determine actual child numbers. In response to stakeholder comments, we converted the secondary tariff into a primary EN tariff that we propose in the Amendment. This tariff is less informationally demanding allowing us to achieve the same level of cost recovery through a directly observable existing charging parameter (ie, capacity charge).
Trigger for TSS Amendment Stakeholders queried how the AEMC's decision could be considered a 'trigger' for the purposes of the rules.	Section B.1 clearly outlines what we consider to be the unforeseen circumstances that have led us to seek amendment of our TSS. These factors are: - new regulatory arrangements for ENs, including 'shadow tariff' arrangements - acceleration of growth in ENs in our network area - AER rejection of our placeholder tariff in April 2019 final determination.

WINConnect made a submission after our Customer Forum supporting more cost reflective network tariffs and arguing that a flat rate per child customer is a poor reflection of true network cost. It raises concerns about collecting data on the number of child connections, the accuracy of this data, transparency of the process to validate this data, and administrative costs including regulatory oversight.

WINConnect suggested that instead of pursuing secondary tariffs per child connection charge, “if Ausgrid believe there is a true variation in cost between the load factors of ENs and other C&I connection profiles, then they should focus on realigning the tariff component best placed to cover that cost component – the demand charge”.

WinConnect also argued against grandfathering existing sites or exempting small customers such as caravan parks.

Caravan & Camping Industry Association NSW expressed concerns about vulnerable customers and provided data on their member energy consumption.

B.4 Our pricing reform

Cost reflective pricing and balancing objectives

We are committed to transitioning to efficient, cost reflective tariffs in a manner that best promotes the long-term interests of our customers, but recognise the efficient pricing outcome is constantly changing. Our customers' preferences and technology are changing, altering the way customers use our network, the costs imposed on our network, and the most efficient means of providing the services our customers expect. In practical terms, tariff efficiency is an objective that we may be constantly working towards, without ever achieving in full, since it is always changing.

Cost reflective pricing must both:

- signal to customers future network costs (also known as Long Run Marginal Cost, LRMC) that could be avoided and
- recover the historical cost of the network (also known as 'residual costs') in a manner that has as little distortionary effect on customer behaviour as possible.

In section B.2 above we demonstrated that our current C&I tariffs are not cost reflective for existing ENs on our network.

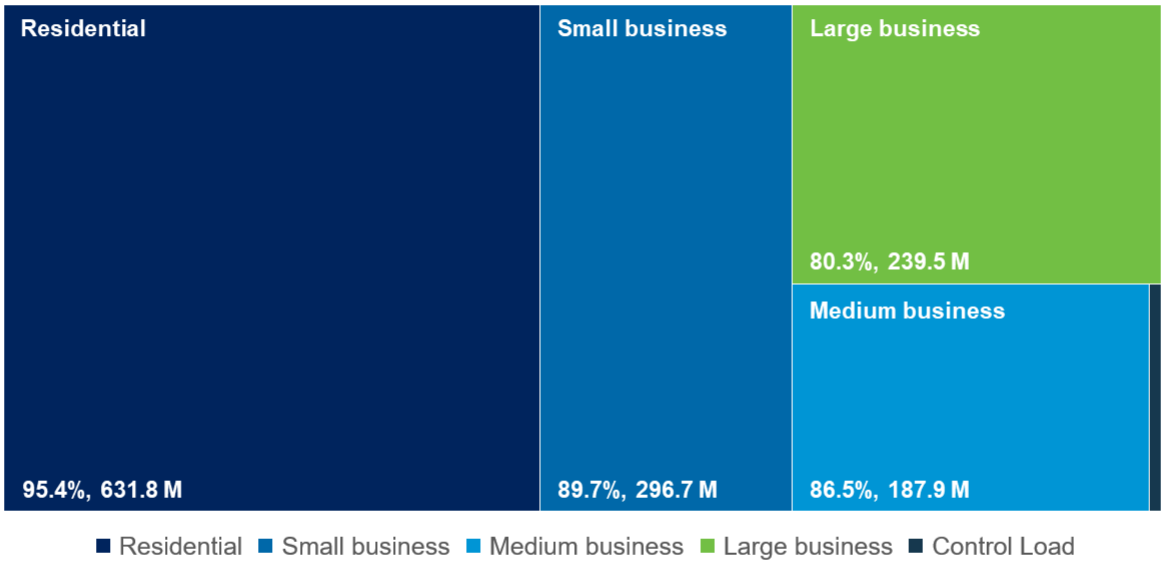
Our tariffs need to recover full efficient costs including residual costs

Our pricing principles imply that peak price should signal Long Run Marginal Cost (LRMC) – the forward looking cost of future network augmentation.

However, pricing at floor LRMC would recover only about 10% of our efficient Distribution Use of System (DUOS) costs. Remaining (residual) costs are allocated across various tariffs, targeting the recovery in the least distortionary way. Some categories of customers bear a larger share of residual costs than other, especially those on legacy (non-cost reflective) tariffs with large customer numbers.

Residential group's residual costs represented 95% of revenue from the group. Large business' residual costs are 80% of the revenue from this group (see Figure B4.1 below). Customers within residential ENs modelled in section B.2 are not different from our residential customers. However, they do not share in residual costs in a similar way.

Figure B4.1. Share of residual costs in DUOS tariff revenue in LV class



Recognising that EN load profiles are different improves tariff efficiency

As demonstrated in section B.2, ENs are different from our average C&I customer. The location of EN creation is also different from our average C&I customer. Recognising these differences with a designated tariff improves overall tariff efficiency. We propose to do so with a default tariff that would apply to newly energised ENs and existing ENs modifying their connection from 1 July 2020, unless exempt by the AER guidelines at that time. We distinguish between residential (including mixed residential) and non-residential ENs, as our analysis in section B.2 demonstrates they have different load profiles.

Our tariffs also fund government policies such as postage stamp pricing and the Universal Service Obligation to connect customers in our distribution area. This is part of our social licence, and customers share the costs of funding these policies as discussed below. An efficient tariff structure would ensure that ENs contribute more equitably to the funding of network policy obligations. Our proposed EN tariffs aim to achieve this objective.

Postage stamp pricing policy

The current postage stamp pricing policy means we charge all our customers, based on their tariff within the tariff class and load profile, the same unit price for our area of operations. Charging parameters (network access charge, energy consumption price and/or demand price) do not differ by location regardless of the cost to supply to the particular location and other site-specific factors not captured in the connection agreement.

In other words, network tariffs reflect the system-wide average cost of supplying the service in our area of operations. This results in geographic cost sharing between retail customers where:

- customers located in areas that are lower than average cost to supply (eg, because they are close to a transmission connection point, there is less vegetation management activity on their feeders or there is less congestion on their zone substation) pay more than the actual cost of supply, and
- customers located in areas that cost higher than average to supply (eg, because they are far from the transmission connection point or their local substation is constrained and requires imminent augmentation) pay less than the actual cost of supply.

The EN operator is not required to set prices on a postage stamp basis. Neither is it currently obliged to extend the connection to any customer within its area of operation (although we note that this will become an obligation following implementation of the AEMC recommendations).

If the tariffs for EN operators were based on the costs of actually supplying network services to each area (ie, a bottom-up ‘cost-of-service’ approach), ENs may face a competitive disadvantage in areas that are more expensive to supply. This is because DNSPs can offer lower network prices to end-use customers in these areas (ie, the postage stamp price), rather than a price that reflects the costs to service that particular location, due to these cross-subsidies (geographic averaging of the costs due to the postage stamp pricing). Alternatively, in areas that are less expensive to supply, the DNSPs may face a disadvantage because they must charge a higher price to end-use customers (ie, the postage stamp price), rather than the price that reflects the actual servicing costs.

The latter case would lead to cherry-picking, where entry occurs only in low cost areas, potentially by inefficient ENs. Cherry-picking increases Ausgrid’s average cost by reducing the low cost customer base while leaving the high cost customer base unchanged. This would push up the postage stamp price as higher than average costs need to be recovered from the remaining customers. In turn, this could lead to further cherry-picking.

On-supply of network services is of a different nature of use to end use

Unlike other C&I customers, ENs do not purchase network services for their own use. They purchase our services at a C&I rate to on-sell to their customers, the end users. Until now Ausgrid has not differentiated between tariffs for end-users (residential and non-residential) and tariffs for on-selling network services. We propose to amend the TSS to differentiate on-selling as the nature of usage is distinct from that of non-residential customers who are end users (cl 6.18.4(1)(i)).

As discussed in the section above, ENs do not have an obligation to serve all customers who apply to them to connect. They are also able to choose the geographic location to operate. They can set their prices without regard to the postage stamp pricing policy. Other sectors dealt with similar wholesale issues, with learnings discussed in the following section.

Learnings from other sectors

Regulatory precedents were created in other network services, eg water and wastewater distribution and supply (the NSW Independent Pricing and Regulatory Tribunal (IPART) 2017 wholesale price review) that set prices for on-selling of network services to end users. [17]

IPART considered three possible alternative approaches for pricing wholesale water and sewerage services purchased for the purpose of on-selling to end users:

- retail-minus approach
- cost-of-service approach, and
- non-residential retail price approach.

IPART found that only the 'retail minus' approach is compatible with postage stamp price regulation.

Under a retail-minus approach, the wholesale price for on-selling a service would be based on the total postage stamp retail price of that service, minus the costs of the contestable service (or services).

The contestable service is the service the wholesale customer is providing (or seeking to provide) to retail customers 'upstream' or 'downstream' of the wholesale services it has purchased from the wholesale service provider. These are services between the wholesale connection point and the end-use (retail) customers, such as reticulation and retail services.

IPART's position was that:

> "To ensure a level playing field between wholesale service providers (incumbents) and wholesale customers (new entrants), and therefore efficient entry and competition for the benefit of water consumers, wholesale prices for on-selling water and sewerage services need to reflect the regulated retail prices for these services".[18]

IPART decided to apply a 'retail-minus' approach for wholesale water and sewerage services purchased for the purpose of on-selling to end-use customers because:

> "This pricing approach allows wholesale customers and wholesale service providers to compete for end-use (or 'retail') customers, without being advantaged or disadvantaged by regulated retail pricing policies that apply to Sydney Water and Hunter Water (such as the

[17] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017.

[18] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017.

postage stamp pricing policy, and differences between regulated residential and non-residential prices)". [19]

This decision applied to a vertically integrated industry. However, the logic of the argument can be applied to the electricity distribution network services, which along with the transmission network services are regulated monopolies. Other segments of the energy supply chain (generation and retail) are competitive and separated from the monopoly transmission and distribution network services.

IPART decided that:

> "…the minus component of retail-minus prices for the wholesale services is to reflect the costs a reasonably efficient competitor would incur in performing retail and/or local reticulation services for their end-use customers (ie, the services from point of wholesale purchase to end-use customers). This approach takes account of the likely smaller scale of wholesale customers (compared to Sydney Water and Hunter Water) and is designed to enable reasonably efficient wholesale customers to match Sydney Water or Hunter Water's postage stamp retail price when supplying end-use customers". [20]

Retail-minus approach encourages efficient entry

IPART argued that the retail minus approach is compatible with postage stamp price regulation and encourages efficient entry.

> "Retail-minus pricing creates a margin for the new entrant (the minus) that reflects an estimate of the cost of the contestable services. This ensures the wholesale service provider (incumbent) and wholesale customer (new entrant) are competing on the basis of their respective costs of supplying the contestable services, rather than on the basis of an arbitrage opportunity or artificial margin created by virtue of the nature of regulated retail prices". [21]

A 'retail minus' approach is consistent with the efficient component pricing rule (ECPR) that encourages efficient entry into downstream markets. Access price at the level below that indicated by the ECPR encourages inefficient entry (see Baumol (1983) and Willig (1979)).[22]

Note that NSW water utilities are regulated based on a price cap. Our form of regulation is a revenue cap, which precludes us from earning any excess monopoly profit if the wholesale price is set at a 'retail minus' or the ECPR approach.

How we propose to proceed

We are guided by the IPART 2017 wholesale price review as the starting point for our tariff.

Applying the IPART's reasoning to the distribution services, in the 'retail minus':

- the 'retail' would be based on network tariffs to end-users as if they were directly connected to the Ausgrid distribution system.
- the 'minus' would reflect the costs of a reasonably efficient competitor to supply electricity distribution services to child connections (the end-users of network services) (see Box B4.1)

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[19] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017, p 40.

[20] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017, p 40.

[21] IPART (2017), *Prices for wholesale water and sewerage services - Sydney Water Corporation and Hunter Water Corporation,* Final Report, June 2017.

[22] Baumol, W. (1983), 'Some Subtle Issues in Railway Regulation', *International Journal of Transport Economics* 10, pp 341-55; Willig, R. (1979), 'The Theory of Network Access Pricing', pp. 109-152 in H. Trebing (ed.), *Issues in Public Utility Regulation*, Michigan State University, Public Utilities Papers.

IPART's methodology also included facilitation costs, which in our case would be covered by connection costs under the connection agreement.

IPART's decision was to limit the application of the system-wide prices to where there is not a recycled water plant. This was to recognise the impacts of the operation of a recycled water plant on the costs of the wholesale service provider.

We consider that in a vertically separated industry such a carve-out is not necessary. ENs with generation and storage facilities receive benefits of lower variable charges due to the reductions in the energy consumption and demand. They are rewarded for their investment via a lower network bill, and lower wholesale energy costs. We consider the tariff would apply to all wholesale customers in a technology neutral way (ie, irrespective of the DER behind the parent meter).

Box B4.1. First-best approach - 'retail minus' tariff

Following IPART's methodology, the 'retail minus' approach to wholesale distribution prices would use:

- **'Retail'** equal to the collection of network tariffs to end-users as if they were directly connected to the Ausgrid distribution system (these are **'shadow tariffs**' in the AEMC's 2019 final report).
- The formula for the EN tariff would take the following form:

$$tariff_{EN} = \sum_{i=1}^{N} tariff_{end-user_i} - C$$

where

- *N* – number of child connections s within the EN within the period,
- C – the **'minus'** – is the Reasonably Efficient Competitor Costs for on-selling of electricity distribution service supplied to the EN at its connection point in that period.
- A system-wide C adapted to electricity distribution would be, eg:

$$C = \text{Cost}_{\$,\ \text{fixed}} * N + \text{Cost}_{\$\ \text{per km Overhead lines}} * \text{Length}_{\text{Overhead lines, km}} +$$

$$+ \text{Cost}_{\$\ \text{per km Underground lines}} * \text{Length}_{\text{Underground lines, km}} +$$

$$+ \text{Cost}_{\$\ \text{capitalised voltage transformer}} * \text{Number}_{\text{Transformers}}$$

- However, there is no visibility of child connection consumption data to calculate the 'retail' network tariff, so this approach is not implementable.
- We consulted on the second-best approach that offered a compromise between economic rigor and ability to implement.
- We received feedback from our customers and modified our approach to reduce informational requirements of the EN tariff achieving a comparable outcome.

Modified 'retail minus' tariff that could be implemented

In section B.2 we demonstrated that a special EN tariff would improve efficiency of our tariff structure and lead to a fairer allocation of the residual costs. We observed that the most important part of the arbitrage was due to the difference in fixed charges.

IPART's 'retail minus' formula, however, cannot be implemented as we currently do not have visibility of the child connection data, to calculate the aggregate network tariff. In addition, the 'minus' component would be difficult to apply system-wide.

Note that the benefits of any embedded DER would be realised to the within-EN connections by way of reduced consumption and demand, so our proposed tariff would be suitable for the EN with embedded DER (that is, technology neutral).

We consulted on a secondary tariff for new ENs on our system from 1 July 2020, or the existing ENs when they modify their connection (unless exempt or grandfathered as discussed in section B.6).

The secondary tariff we consulted on would apply in addition to the main tariff and would be based on the number of all child connections by type during the year.[23] The information on the number of child connections would be updated annually and used as the basis for the secondary tariff for the following year. We would require the ENs to report this information to us via their retailers. If the information was not reported, we would use best available information to estimate the number and type of child connections within the EN.

The secondary EN tariff we consulted on was a fixed daily charge per child connection, based on the type of connection. This 'second-best' tariff did not remove the full arbitrage, allowing the savings on aggregated energy consumption and diversified demand to be retained by the EN.

We received stakeholder feedback on the difficulties to implement the secondary tariff, especially to establish clear and transparent processes to determine actual child numbers.

In response to stakeholder comments, we converted the secondary tariff into a primary EN tariff that we now propose. This tariff is less informationally demanding allowing us to achieve the same level of cost recovery through directly observable, existing, charging parameter (ie, capacity charge).

How we calculated the modified 'minus' for the fixed charge

Because the secondary tariff we consulted on was unable to remove all arbitrage, we did not provide the full 'minus' (see Box B4.1). But our 'retail' was also not the full 'retail', only a fixed component of the sum of individual network tariffs for end users.

As such, we estimated the 'minus' that would reasonably apply to the fixed charge. To do that, we estimated savings that accrue to us due to not servicing within-EN customers. Our logic is explained below.

EN arrangements do not save us network connection costs

We compared a standard strata development with an EN.

For a standard strata development that are our direct customers:

- Each customer has their own on market meter.
- These meters are co-located at a single physical location.
- Electrical wiring on common property is owned and managed by the strata.
- Each customer is responsible for the wiring located on their property.
- Ausgrid is responsible for everything upstream of the co-located connection points.
- Metering is a contestable service meaning Ausgrid does not incur meter installation costs.

For a strata development with an EN, up until now the arrangements have been:

[23] This includes both on-market and off-market connections.

- The developer installs a single on market parent meter and applies to Ausgrid to become an EN.
- The Exempt Network Operators (ENO) takes over management of the electricals on the site from the body corporate, and may issue child meters to their embedded customers.
- Ausgrid is responsible for everything upstream of the parent meter.
- Ausgrid has no visibility of child meters or of the ENs customers.
- The co-location of meters in a typical strata means that connection costs to Ausgrid are not different between the two arrangements.

This situation describes a standard LV connection. For higher voltages, there are capital cost savings associated with not owning and maintaining the connection assets. These costs have been annualised and included in the calculation of savings applicable in HV and ST classes.

EN arrangements save us some network operating costs

EN arrangements save us some network operating costs. However, these savings are achieved only by not providing the same level of reliability to within-EN child connections.

- Ausgrid's reliability metrics are based on the number of customers affected by an interruption, and its value and duration.
- These metrics are used to determine our network performance, and in our planning processes to determine the efficient level of investment in network infrastructure, where we must meet minimum service requirements.
- An outage of an EN would be underrepresented in our reliability statistics, as there is only one EN customer effected by the outage, regardless of the number of child connections within it.
- Customers within an EN have no rights to guaranteed service standard payments. These payments are on a per customer basis.
- Life support customers within an EN may not be fully visible (only one life support flag will apply to the parent connections regardless of the actual number of life support customers).

By not being required to provide the same level of reliability and life support obligations to within-EN child connections as for our directly connected customers, Ausgrid does save on operating costs. We estimate these savings to be about $5 per our customer per year. We take these savings into account when calculating the proposed tariff discussed later in this section.

We consulted on a ‘second best’ tariff with our customers

We proposed the ‘second-best’ option in the form of a secondary tariff that only removed the arbitrage in the fixed daily charge component of residual cost allocation. We flagged a possibility of developing a ‘first-best’ shadow tariff in the event that within-EN child meter data becomes available for the next regulatory period.

This ‘second best’ tariff was easy to understand and allowed us to maintain our approved TSS unaltered, providing certainty to the vast majority of our customers.

In proposing the tariff, we needed to balance the competing needs of all customers, including EN customers. Because the tariff did not fully rectify inefficiency, its entailed:

- some level of cross-subsidy from residential and small business customers to ENs persisting in future
- not fully preventing the inefficient entry of ENs whose business model is dependent on arbitrage rather than providing an efficient service.

Considering stakeholder comments on the administrative complexity of the secondary tariff, and that capacity is a better parameter to apply the charge to, we converted the secondary tariff into a primary EN tariff that we propose in this amendment.

The proposed primary EN tariff mimics the effect of an increased fixed charge by applying a mark-up on the capacity charge that applies to a C&I tariff for a customer of a similar usage and profile, but different nature of use (end user vs on-supplier). We distinguish between residential (including mixed residential) and non-residential ENs, as our analysis demonstrates they have different load profiles.

The capacity mark-up is on average proportionate to the number of child connections absorbed by the EN, by way of the diversity factor and the average. EN customers are rewarded if they reduce peak capacity further, by lowering the base to which the capacity charge will apply.

We considered that the mark-up on capacity would compensate for:

- the wider peak windows to include residential evening peaks of residential ENs, and
- for lower diversity of the non-residential ENs within the C&I customer group.

We kept the business peak charging windows unchanged for all C&I customers, to provide certainty for the remainder of the 2019-24 regulatory period and minimise administrative and implementation costs.

Our proposed tariff sends a better signal for efficient entry

Our proposed tariff for ENs sends a better signal for efficient new entry to the market for end-use electricity distribution services and promotes competition for the benefit of all consumers (both within-EN and the wider customer base, including C&I customers and residential customers). The entry would be much less likely to be driven purely by an arbitrage opportunity.

Our proposed EN tariffs:

- encourage efficient entry of EN operators where it would result in lower prices (at the same or better service levels) or enhanced service levels over time for all end-use customers, and
- do not encourage inefficient entry where it would result in higher prices over time for end-use customers.

Structure of the EN tariff

We consulted on a secondary EN tariff as a fixed charge per day per child connection by connection type.

We provided calculations of this tariff with our pricing model. We converted these amounts to primary tariffs applying a mark-up to a capacity charge.

How we calculated this charge

We based our calculation on the EA310 (>750 MWh pa) tariff for large LV customers. This is the tariff where 50% of ENs in our distribution area are assigned to, based on their connection characteristics and consumption level.

We based our tariff on the principle that we require a contribution from within-EN customers equivalent to that by our direct customers in funding the fixed network access costs, adjusted by the costs we avoid or already recover via the primary tariff.

(1). We start with the fixed charges that we would recover on average from a within-EN customer if we service this customer directly. We calculate it as a weighted average fixed charge, weighted by the number of customers assigned to a particular tariff within a group (eg, residential).

(2). To avoid double-recovery of fixed charges already included in the fixed charges under the primary C&I tariff, we:

(a) estimated the ‘multiples’ of residential and business category customers that can fit into an average EA310 customer consumption, based on annual averages.

(b) divided the fixed charge on the primary tariff (modelled as EA310 due to the prevalence of this tariff across ENs in our distribution area), by the equivalent number of average child connections of this type calculated in (a) above, and

(c) subtracted this amount from the daily fixed charge in (1), effectively ‘rebating’ the EN customer for the fixed charge already paid through the primary tariff.

(3). Further reduced the charge to account for cost savings to us resulting from not servicing the within-EN customers directly, including:

(a) avoided costs from outage notification, and

(b) the reduction in the reliability responsibility (see Table A4.2 below).

Table A4.2. Calculation of the secondary charge for a residential child connection.

Steps	Calculation	Price
A	Weighted average fixed charge we would recover from the within – EN customer if we serviced them directly	39 c/day
B	Fixed charge already recovered under the primarty tariff: • Fixed charge included in the primary C&I tariff (e.g. EA310 the most common for ENs) $25.00/day • The load of an average EA310 customer equates to 314 average residential customers • Fixed costs already recovered per customer: $25 / 314 = 8 c/day	Less 8 c/day
C	Cost savings to Ausgrid from not servicing the within – EN customers directly, including avoided costs from outage notification, and reduce reliability responsibility.	Less 1 c/day
	Fixed charge per child residential connection	**30 c/day**

We repeated the calculations for HV and ST ENs to calculate secondary tariffs that would be appropriate to those customers.

Having calculated these amounts, we converted them to the revenue requirement that we now propose to recover by applying a mark-up to a capacity charge on new primary EN tariffs.

B.5 Our pricing principles

New sub-section is added to this section.

Improving efficiency of our tariffs

Unlike other C&I customers, EN operators do not purchase our network services for their own use but on-sell in the downstream markets.

Under the rules, the services need to be provided efficiently. The new tariff methodology will improve economic efficiency of our tariffs ensuring that network services are provided efficiently to all our customers. It would also ensure that new entry to the market for end-use electricity distribution services would promote competition for the benefit of consumers.

Our proposed tariff:

- encourages efficient entry of EN operators where it would result in lower prices (at the same or better service levels) or enhanced service levels over time for all end-use customers, and
- does not encourage inefficient entry where it would result in higher prices over time for end-use customers.

Our tariffs should endeavour to send a price signal for efficient new entry to the market for end-use electricity distribution services and promote competition for the benefit of all consumers.

B.6 Our customer impacts

The AEMC's proposed regulatory changes impose additional obligations on EN businesses which may increase operating costs for some of these businesses. Having considered the trade-offs between the benefits of providing customers with improved protections and access to retail competition and the costs to EN owners and operators, the AEMC proposed a final framework that achieves an appropriate balance, particularly in respect of legacy networks. While the costs to ENs may increase, prices for EN customers may come down due to these EN businesses having to compete with other retailers to keep their customers.[24]

The AEMC's proposed framework facilitates the establishment of ENs where it is efficient to do so, without compromising consumer protections or access to retail market competition.

Implementing the proposed framework may therefore alter the incentives for establishing an EN depending on the nature of the entity, the type of development and the number and types of end customers. The AEMC recognises that small entities, such as a single owners' corporation, will find it costly to become registered and authorised and to comply with the proposed framework. Smaller developments may also find the cost of connecting premises directly to the local distribution network may be more cost effective than establishing EN arrangements.[25]

Our amendment to the TSS appropriately balances the need to improve the efficiency of our network tariffs against the important requirement to consider the impact of these tariff reforms on customers, and to provide price certainty for the remainder of the 2019-24 regulatory period.

The AEMC's proposed regulatory changes pave the way for us to address distributional effects of ENs in our distribution areas while managing the impact on within-EN customers.

Customers that are affected by our proposal are EN operators and their (within-EN) customers, and our wider customer base. Our wider customer base is the beneficiary of the proposed tariff, as they will pay a smaller, and fairer, share of total efficient costs as a result of the proposal. The proposed tariff reduces cross-subsidies from our customers to ENs as demonstrated below.

We discuss in turn the estimated impacts of our proposal on the wider customer base, EN operators, and their end use customers

Our wider customer base is better off under the proposed EN tariff

We note the AER's view that, if distributors believe that differences in network pricing across tariff classes are incentivising ENs, any proposal should be accompanied by detailed modelling establishing that the incentive exists, and its existence is not in the long-term interests of consumers.[26]

In section B.2 we provided examples of the arbitrage that accrues to ENs. We demonstrated and quantified the incentives to create ENs. In section B.4 we argued that inefficient entry of ENs is not in the long-term interest of our customers.

Extrapolating the growth forecast of ENs, we calculated the difference between the sum of residential (or small business) tariffs and the C&I tariff applied to their aggregated load in each new EN.

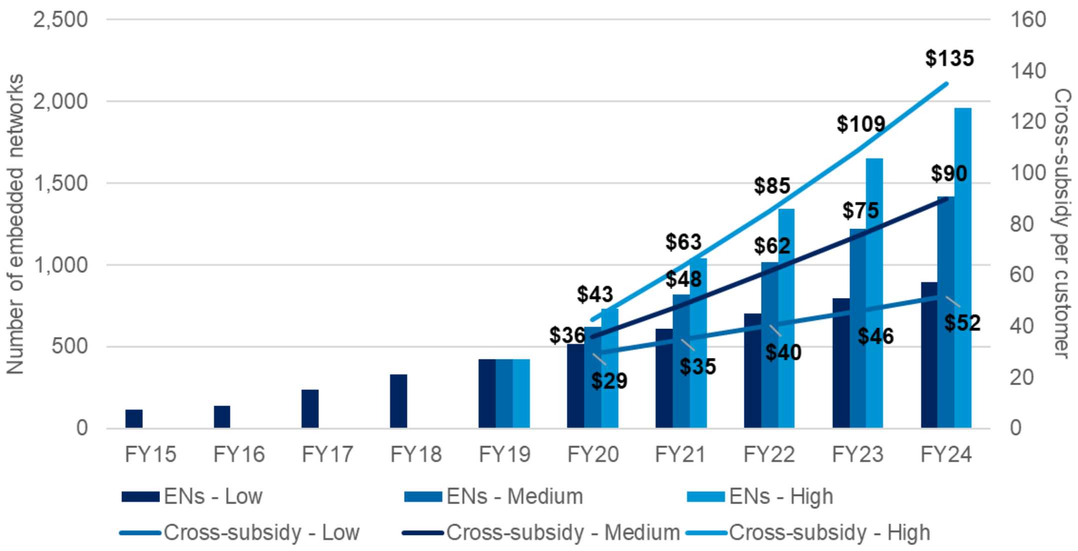
We called this difference a cross-subsidy provided by the wider customer base to ENs. This cross-subsidy is the arbitrage captured by ENs that could otherwise be contributing to shared network costs to the benefit of all customers.

[24] AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, p vii.
[25] AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2019, p vii.
[26] AER (2018) *Draft Decision TasNetworks Distribution Determination Attachment 18 – Tariff Structure Statement,* pp 18-28 and 18-29.

Our conservative estimate of the level of cross-subsidy from our residential and small business customers to ENs is:

- $29 per customer per year in 2019-20, rising to
- $52 per customer per year by 2023-24 if no change to the TSS is made (see Figure B6.1).

Figure B6.1. Estimated growth in ENs vs cross-subsidy



Secondary EN tariffs we consulted on remove about half of cross-subsidy

We applied a secondary EN tariff we consulted on to the synthetic examples of ENs presented in section B.2. We calculated an equivalent EN tariff applied a mark-up on a capacity charge, to achieve a comparable outcome. In our examples, the arbitrage was substantially removed.

In our modelled examples of residential, commercial and mixed ENs:

- residential EN's arbitrage reduced from $61,000 or 46% of network charges under our 2019-20 tariffs, to $27,000 or 21% with the application of a secondary EN tariff, and further to $25,000 or 20% under the EN tariff proposed in this Amendment (see Box B6.1)
- commercial (non-residential) ENs' arbitrage in two configurations reduced from:
  - arbitrage of $40,000 or 23%, to $21,000 or 12% with the application of a secondary EN tariff, and further to $13,000 or 8% under the EN tariff proposed in this Amendment.
  - arbitrage of $25,000 or 31% of network charges, to $7,000 or 9% with the application of a secondary EN tariff, compared to $15,000 or 19% under the EN tariff proposed in this Amendment (see Box B6.2).
  - mixed residential EN's arbitrage reduced from $74,000 or 42% of network charges, to $35,000 or 20% with the application of a secondary EN tariff, and further to $13,000 or 8% under the EN tariff proposed in this Amendment (see Box B6.3).

Box B6.1. Analysis of revenue impact from EN– residential

Modelling inputs

Interval data for 315 NMIs of residents in an apartment block each on a TOU network tariff.

The what if scenario

Total Network Use of System charges for the 315 individual NMIs on the 2019-20 seasonal TOU tariff (EA025) vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff vs as an embedded network on a large business EN tariff of EA347 of LV EN Non-Residential >750 MWh.

Comparison of Network Use of System revenue, 2019-20

EN:315 NMIs	Individual NMIs in Ausgrid Network (EA025 TOU)	Individual NMIs in EN (EA310)	Individual MMIs in EN (EA310 and secondary EN tariff)	Individual NMIs in EN (EA347)
Consumption per NMI	3,268 kWh			
Total consumption	1,029,409 kWh			
Fixed – network access charges	$52,934	$9,106	$9,106	$9,106
Energy consumption charge (kWh)	$72,506	$19,082	$19,082	$19,082
Demand/capacity charge (kVA)	-	$36,161	$36,161	$72,321
Secondary EN charge	-	-	$34,493	-
Total network bill pa	**$125,441**	**$64,349**	**$98,842**	**$100,510**
Difference ($)		**-$61,092**	**-$26,599**	**-$24,931**
Difference (%)		**-46%**	**-21%**	**-20%**

Box B6.2. Analysis of revenue impact from EN – two businesses

Modelling inputs

Data from NMIs on a mix of tariffs using two business examples: two buildings likely to be a business centre with many offices.

The what if scenario

Total Network Use of System charges for the individual NMIs on their 2019-20 tariff vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff vs as an EN on a large business EN tariff of EA357 of LV EN Non-Residential >750 MWh.

Comparison of Network Use of System revenue, 2019-20

EN A: 13 NMIs on 4 different tariffs	**Individual NMIs in Ausgrid Network EA225, EA302, EA305, EA316)**	**Individual NMIs in EN (EA310)**	**Individual NMIs in EN (EA310 and secondary EN tariff)**	**Individual NMIs in EN (EA357)**
Consumption per NMI	147,014 kWh			
Total consumption	1,911,176 kWh			
Fixed – network access charges	$26,851	$9,106	$9,106	$9,106
Energy consumption charge (kWh)	$56,283	$37,788	$37,788	$37,788
Demand/capacity charge (kVA)	$91,459	$88,152	$88,152	$114,598
Secondary EN charge	-	-	$18,980	-
Total network bill pa	**$174,593**	**$135,047**	**$154,027**	**$161,492**
Difference ($)		**-$39,546**	**-$20,566**	**-$13,101**
Difference (%)		**-23%**	**-12%**	**-8%**

EN B: 25 NMIs on 3 different tariffs	**Individual NMIs in Ausgrid Network (EA050, EA225, EA302)**	**Individual NMIs in EN (EA310)**	**Individual NMIs in EN (EA310 and secondary EN tariff)**	**Individual NMIs in EN (EA357)**
Consumption per NMI	30,387 kWh			
Total consumption	759,666 kWh			
Fixed – network access charges	$22,541	$9,106	$9,106	$9,106
Energy consumption charge (kWh)	$4,812	$14,742	$14,742	$14,742
Demand/capacity charge (kVA)	$13,787	$32,359	$32,359	$42,067
Secondary EN charge	-	-	$17,885	-
Total network bill pa	**$81,140**	**$56,207**	**$74,092**	**$65,915**
Difference ($)		**-$24,933**	**-$7,048**	**-$15,225**
Difference (%)		**-31%**	**-9%**	**-19%**

Box B6.3. Analysis of revenue impact from EN– mixed residential

Modelling inputs
Data from NMIs on a mix of residential and non-residential tariffs – 315 residential NMIs on EA025 and 6 non-residential NMIs on EA025, EA225 and EA302.

The what if scenario
Total Network Use of System charges for the individual NMIs on their 2019-20 tariff vs as an EN on a large business tariff of EA310 >750 MWh a year and a secondary EN tariff vs as an EN on a large business EN tariff of EA347 of LV EN Non-Residential >750 MWh.

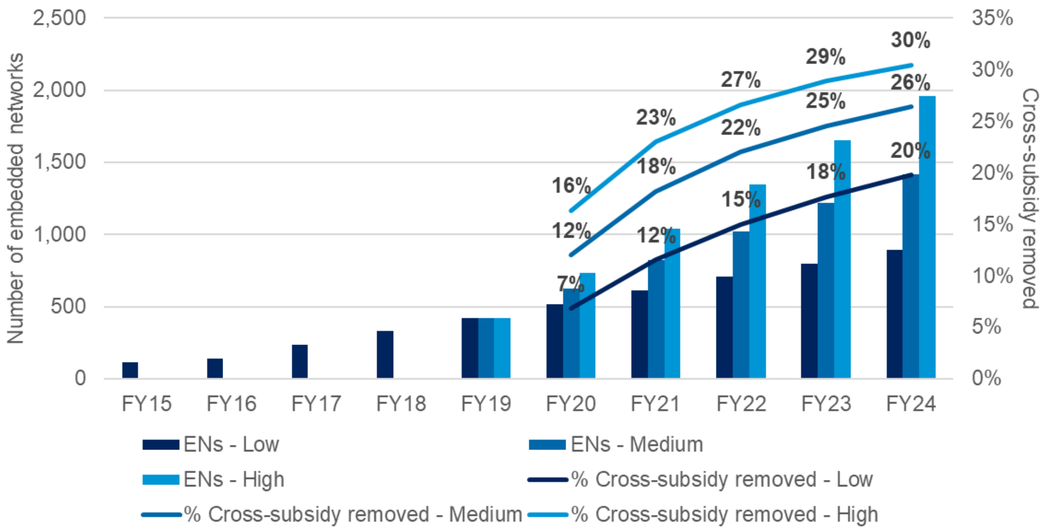
Comparison of Network Use of System revenue, 2019-20

EN: 315 residential NMIs and 6 non-residential NMIs	Individual NMIs in Ausgrid Network (EA025, EA225, EA302)	Individual NMIs in EN (EA310)	Individual NMIs in EN (EA310 and secondary EN tariff)	Individual NMIs in EN (EA347)
Consumption per NMI	17,874 kWh			
Total consumption	1,662,272 kWh			
Fixed – network access charges	$58,447	$9,106	$9,106	$9,106
Energy consumption charge (kWh)	$110,061	$30,449	$30,449	$30,449
Demand/capacity charge (kVA)	$6,102	$61,109	$61,109	$122,217
Secondary EN charge	-	-	$38,873	-
Total network bill pa	**$174,611**	**$100,664**	**$139,537**	**$161,773**
Difference ($)		**-$73,947**	**-$35,074**	**-$12,838**
Difference (%)		**-42%**	**-20%**	**-7%**

The aggregate cross-subsidy to ENs would reduce after application of the EN tariffs. Grandfathering existing ENs limits effectiveness of the EN tariffs by removing part of cross-subsidy from new ENs only. Our proposed EN tariff, assuming grandfathering of existing ENs, removes an estimated 20% of the total cross-subsidy and delivers a benefit of $10 per customer per year by 2023-24 (see Figure B6.2).

We will be reviewing the price levels of our EN tariffs as more data on ENs become available during the 2019-24 regulatory period, to ensure they remain cost reflective and effective.

Figure B6.2. Percent total cross-subsidy removed with the EN tariff



Impacts on legacy ENs are mitigated by grandfathering and exemptions

Our customer advocates told us they do not want existing ENs exempted from the EN tariff as this would result in existing cross-subsidies persisting for longer. Our EN customers oppose the proposed tariff but should it be accepted, argue they should be grandfathered.

On balance, we are reluctant to apply the new EN tariff to existing ENs in this regulatory period as:

- The AEMC upgraded EN framework and rule change will not be in place for some time. Without immediate access to retail competition, the within-EN 'child' customer might receive a price shock if the 'parent' EN passes through the increase in network charges. Retail competition would ensure that such a cost pass-through is not feasible.
- Existing ENs whose business model is dependent on arbitrage may go out of business with the sudden change in costs following the implementation of a secondary tariff, potentially causing serious disruption for their customers.

Our preference is to grandfather existing ENs, only applying the default EN tariff to new ENs and those ENs modifying the existing connection. This will allow EN operators to consider the effect of the EN tariff when making business decisions, preventing bill shocks for existing within-EN customers.

Proposed exemptions follow the AER's Guidelines

The AEMC excluded legacy ENs subject to deemed and individual exemptions from the transitional framework. We propose to limit grandfathering of legacy ENs to the time when they upgrade or modify their connection. This is consistent with our approach to tariff reform, in particular the introduction of demand tariffs for residential and small business customers. We did not permanently grandfather customers on flat tariffs/ accumulation meters. Our logic is consistent in implementing the proposed reform and rolling out of EN tariffs.

There are no impacts on existing ENs on 1 July 2020. Existing ENs would be impacted when they upgrade or modify their connection after 1 July 2020. We propose to manage these impacts by aligning exemption criteria for the EN tariff to those set by the AER's guidelines applicable at the time of connection change.

We consider that new ENs energised after 1 July 2020 will have made their business decision with the knowledge of the secondary tariff that would apply to them. They would also have allowed for additional compliance costs associated with the AEMC's proposed updated regulatory framework that would apply from the effective date (estimated 1 July 2021).

In making this proposal we address the concerns of our customer advocates regarding vulnerable customers (such as caravan parks) that might be affected by our proposed changes unless protected by access to retail competition or retail price regulation by the AER. We also limit application of the EN tariff to customers with consumption above 160 MWh pa, so that small legacy ENs such as caravan parks are not affected by this proposal. These small customers are not included in our EN data analysis, as they have not been registered in our system as an EN.

Timing of the tariff

We propose to apply the new tariff from 1 July 2020 to newly energised ENs and existing ENs upgrading or modifying their connection, unless exempt under the AER's exemption guidelines applicable at the time of energisation or connection change.

We have consulted with our customers at a Customer Forum on aligning the timing of the proposed tariff change to the commencement of the AEMC's proposed regulatory framework for ENs. EN and caravan park industry representatives argued for us waiting until the AEMC proposed reform commences.

The drawback of us waiting for the regulatory reform to become effective is locking in a higher level of cross-subsidy. Delaying the new tariff would disadvantage the wider customer base, advantaging EN operators (by allowing a higher number of them to be grandfathered) and their end customers (by ensuring that retail competition is already protecting them).

Within-EN customers will be protected by retail competition

Within-EN end customers will be protected by retail competition that the updated regulatory framework creates. End users within legacy ENs will be protected by retail price regulation that AER will assume in relation to these customers. We agree that without the safety net provided to within-EN customers by exposure to retail competition, our proposed EN tariff could result in a price increase to within-EN end users.

The AEMC decided to exclude those legacy ENs subject to deemed and individual exemptions from the transitional framework.[27] Current deemed exemption classes are provided in AER's registration exemption guidelines (March 2018).[28] The AEMC's transitional framework is outlined in section B.1.

If we were to align the timing of our tariff to the timeline of the AEMC's regulatory framework, we would limit application of the new EN tariff to those ENs that are not exempt under the new framework. Effective date is the first anniversary of the commencement day. Estimated commencement day is 1 July 2020, and effective date 1 July 2021.[29]

- New ENs that are established from 1 January 2020 to the effective date (1 July 2021) - the EN tariff would apply from 1 July 2022.
- New ENs established after the effective date – from the date when energized.

27 AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2010, pp 210-213.
28 AER (2018), *Electricity Network Service Provider - Registration Exemption Guideline,* Version 6, March 2018, pp 29-31.
29 AEMC (2019), *Updating the regulatory frameworks for embedded networks*, Final report, June 2010, pp 210-213.

- Legacy ENs established between 1 December 2017 – 31 December 2019 upgrading or modifying their connection from 1 January 2020 to the effective date +2 years - that is, the EN tariff would apply from 1 July 2023.
- Legacy ENs established between 1 December 2017 – 31 December 2019 upgrading or modifying their connection after the effective date + 2 years (that is, after 1 July 2023) - from the date of the upgrade.
- Legacy ENs established prior to 1 December 2017 – the AEMC recommended no changes for registered exempt networks. Their arrangements have been grandfathered into the new arrangements. The EN tariff would not apply.

This option would mean that the earliest the EN tariffs apply would be:

- From 1 July 2021 - to new ENs established after the effective date (1 July 2021) that will be required to comply with the new regulatory framework immediately.
- From 1 July 2022 - to new ENs established from 1 January 2020 to the effective date (1 July 2021).
- From 1 July 2023 – to ENs established between 1 December 2017 – 31 December 2019 upgrading or modifying their connection from 1 January 2020 to the effective date (1 July 2021).

In that alternative option, ENs established prior to 1 December 2017 permanently grandfathered from the EN tariff, the existing cross-subsidy would be protected and be given additional time to grow.

Our preferred and proposed is to introduce the new default EN tariff from 1 July 2020, and to apply it to newly energised ENs and existing ENs upgrading or modifying their connection, unless exempt under the AER's guidelines applicable at the time of the energisation or connection change.

B.7 Complementary measures

No change to this section.

B.8 Glossary

These additional terms are added to the Glossary

AEMC	Australian Energy Market Commission
Child connection	The point of supply between an embedded network and a customer, generating unit or other embedded network connected to that embedded network and served by that embedded network
DNSP	Distribution Network Service Provider
Embedded Network	A network other than a registered TNSP or DNSP, which is connected to a distribution or transmission network at a parent connection point, and on-sells to customers connected at 'child' connection points (end users or other embedded networks).
EN	Embedded Network
Parent connection	The agreed point of supply between an embedded network and a transmission or distribution system that is serving an embedded network
TNSP	Transmission Network Service Provider

B.9 List of attachments and status

This document, our Tariff Structure Statement including Appendix A Explanatory Notes, is Attachment 10.01 to our Revised Proposal. Other attachments referred to in this document and part of our Revised Proposal are listed below. **Attachments in bold have been revised for our amended TSS.**

Attachment	Status
This document is **10.01 Tariff Structure Statement**	Revised, split into two documents including Appendix A Explanatory Notes This document is Amended TSS, which includes a new Appendix B Explanatory Notes to the Amendment
10.02 Procedure for Assigning Customers to a Tariff Class	No change from Initial Proposal
10.03 Long Run Marginal Cost Model	No change from Initial Proposal
10.04 Long Run Marginal Cost Methodology Report	No change from Initial Proposal
10.05 Tariff Model (Standard Control Services)	**Revised to include Amended TSS**
10.06 ES7 Network Price Guide, July 2019	**Revised to reflect Amended TSS**
10.07 Price Elasticity	No change from Initial Proposal
10.08 Transmission Pricing Methodology	No change from Initial Proposal
10.09 Methodology for Avoided TUOS Charges	No change from Initial Proposal
10.10 Indicative Pricing Schedule – DUOS Charges	**Revised to reflect Amended TSS**
10.11 Indicative Pricing Schedule – TUOS Charges	**Revised to reflect Amended TSS**
10.12 Indicative Pricing Schedule – ACS Charges	Revised to reflect our Revised Proposal
10.13 Indicative Pricing Schedule – Climate Change Fund	**Revised to reflect Amended TSS**
10.14 Pricing Directions: A Stakeholder Perspective	No change from Initial Proposal
10.15 Energy Volume Forecast, January 2019	New for Revised Proposal