Ergon Energy Pricing Proposal

Distribution services for 1 July 2021 to 30 June 2022

31 March 2021

NETWORK

Version	Date	Description
V1.0	31/03/2021	Pricing Proposal submitted to the AER for approval
V2.0	23/04/2021	Updated Pricing Proposal submitted to the AER

Contents

Overview

This pricing proposal is submitted to the Australian Energy Regulator (AER) as required under the requirements of the National Electricity Rules (NER). It provides details of Ergon Energy's proposed 2021-22 network prices for Standard Control Services and Alternative Control Services.

Our pricing proposal is based on the AER approved 2020-25 Tariff Strategy Statement (TSS).

In 2021-22 Ergon Energy is proposing to introduce five new tariffs for low voltage (SAC residential and business) customers:

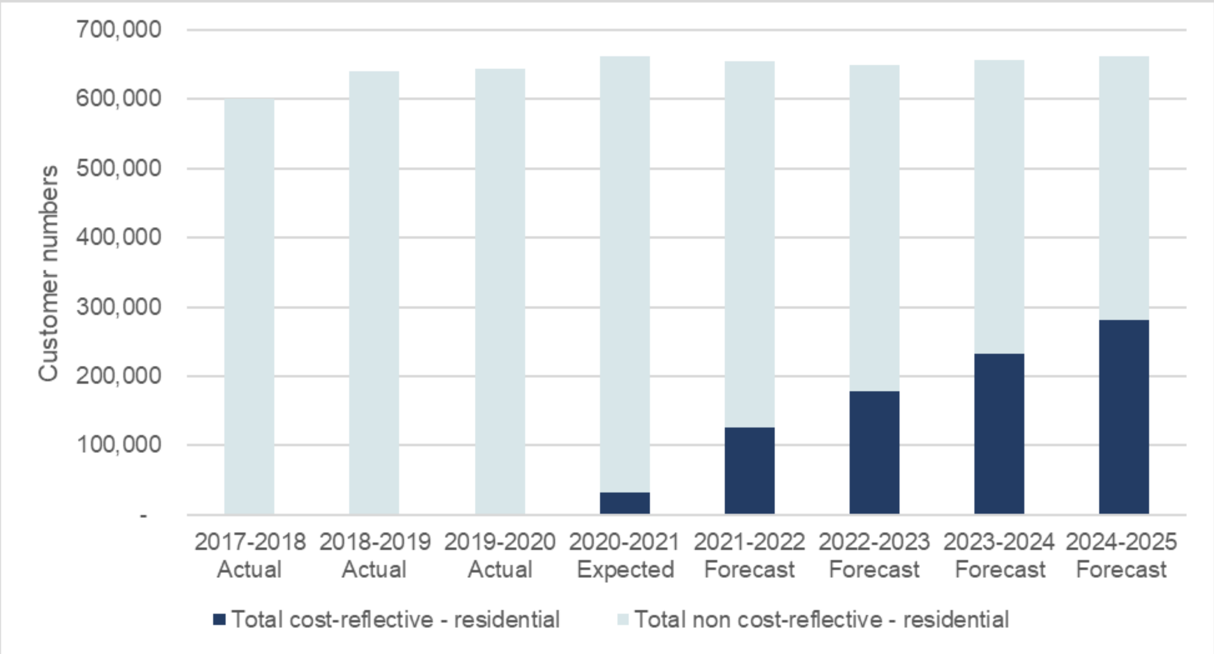
- Two tariffs for residential and business customers with basic metering consuming more than 100 MWh per year. These tariffs will be the default tariffs for all large basic metering customers (approximately 350 existing customers).
- Three optional transitional tariffs available to customers consuming less than 100 MWh per year in the East pricing zone who are, or have been on transitional retail tariffs 62, 65, or 66 in the period 1 July 2017 to 30 June 2020.

These new tariffs have been developed in alignment with the AER's Final Decision on our 2020-25 TSS.

Further, from 1 July 2021 our Transitional Demand tariffs become the default assignment for residential and small business customers with smart meters and customers who initiate an upgrade to a smart meter[1]. Approximately 150,000 customers will be reassigned from the legacy inclining block and WIFT tariffs to the Transitional Demand tariffs on 1 July 2021, further advancing our tariff reform toward cost reflectivity.

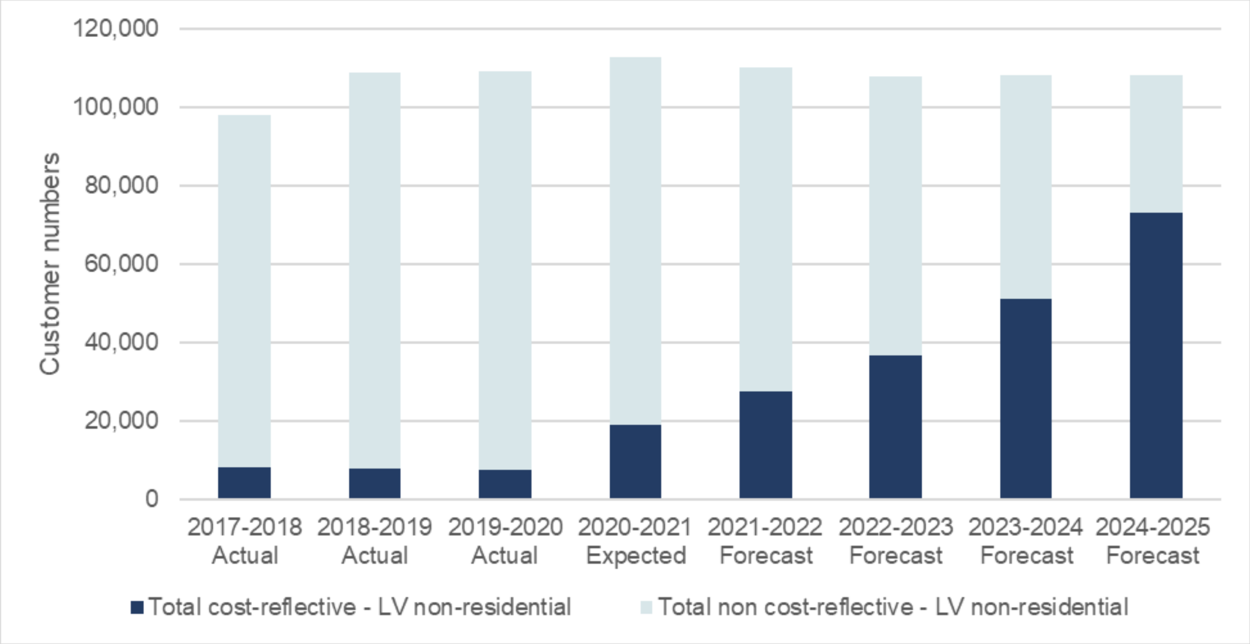
The charts below show the historic and forecast annual customer number movements from legacy tariffs to cost-reflective (demand and energy time-of-use based) tariffs from 2017-18 to 2024-25.

Figure 1: Residential customer numbers by tariff type



[1] In accordance with our TSS, residential and small business customers that have their metering replaced due to end of life replacement will be able to remain on their legacy tariff for a period of 12 months from the date of meter replacement.

Figure 2: Non-residential LV customer numbers by tariff type



Ergon Energy estimates that residential and small business with smart meters are expected to experience a slight increase in their network charges (less than 2%), while basic metering customer will experience a modest increase (up to 6% for legacy IBT tariffs) in 2021-22 compared with 2020-21 network charges.

Ergon Energy's large business customers (SAC Large) are expected to experience an increase in network charges of between 1%-5% in 2021-22, compared to 2020-21. This change in network rates is mainly driven by the forecast decrease in energy consumption resulting from the economic impacts of COVID-19 pandemic and increases in Powerlink's transmission charges.

1. Introduction

1.1 Purpose

This document is Ergon Energy's annual Pricing Proposal for 2021-22 (Pricing Proposal), the second regulatory year of the 2020-25 regulatory control period. In accordance with clause 6.18.2(a)(2) of the National Electricity Rules (the NER)[2], it is submitted for approval to the Australian Energy Regulator (AER) at least 3 months before the commencement of the relevant regulatory year.

This Pricing Proposal is based on the AER approved 2020-25 TSS and outcomes in the AER's Final Decision. Ergon Energy's approved 2020-25 TSS is available on our website[3] and is also available on the AER's website[4].

1.2 Background

Ergon Energy is subject to economic regulation by the AER under the National Electricity Law and the NER. The AER determines how Ergon Energy's distribution services are classified and in turn the nature of economic regulation. This is important as it determines how prices will be set and how revenue is recovered from customers. The AER approves prices for services it classifies as Direct Control Services.

Direct Control Services are divided into two subclasses:

- **Standard Control Services** are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services. The AER applies a revenue cap form of control to Standard Control Services. Ergon Energy recovers the costs in providing these services through network tariffs billed to retailers.
- **Alternative Control Services** are akin to a 'user-pays' system whereby the whole cost of the service is paid by those customers who benefit from it, rather than recovered from all customers. Ergon Energy's Alternative Control Services are comprised of:
  - Connection services – services relating to the electrical or physical connection of a customer to the network (including temporary connections, de-energisations, re-energisations and supply abolishment).
  - Metering services – services include Type 6 default metering services, auxiliary metering services and provision of services for approved unmetered supplies.
  - Public Lighting services – services relating to the provision, installation and maintenance of public lighting assets and emerging public lighting technology.
  - Network ancillary services – customer and third party initiated services related to the common distribution services but for which a separate charge applies (includes network safety services, non-standard network data requests, security lighting services).

This Pricing Proposal (and the attachments forming part of this Pricing Proposal) sets out proposed tariffs and services for all Ergon Energy's Direct Control Services for the 2021-22 regulatory year.

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[2] The National Electricity Rules, Version 156.

[3] https://www.ergon.com.au/network/network-management/network-pricing/network-tariffs

[4] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/final-decision

1.3 Regulatory framework

1.3.1 Compliance with the NER

Ergon Energy's network tariffs have been developed in compliance with the NER. In accordance with clause 6.18.5(a) of the NER, our objective is to ensure that the tariffs charged for 2021-22 in respect of the provision of Direct Control Services reflect Ergon Energy's cost of providing these services. This is achieved by setting the level (or price) of tariffs in a manner that is consistent with the pricing principles as outlined in clauses 6.18.5(e) to (j) of the NER. More detailed information about our application of, and compliance with, the distribution pricing principles is set out in Section 8 and Appendix B: Compliance Checklist of this Pricing Proposal.

1.3.2 Consistency with the Distribution Determination

The 2020-25 Distribution Determination sets the revenue and pricing control regime that we must comply with for the regulated distribution services provided over the current regulatory control period. The revenue approved in the Distribution Determination forms the basis of Ergon Energy's prices provided in Attachment 1 – 2021-22 Network Price List and Attachment 2 – Indicative Pricing Schedule 2021-25. We confirm this Pricing Proposal complies with AER's Final Decision.

1.3.3 Consistency with the approved TSS

The TSS sets out our proposed tariff classes, tariffs and tariff structures that will apply over the regulatory control period. This Pricing Proposal is based on our approved 2020-25 TSS, and several sections of this Pricing Proposal therefore refer to the TSS for further information. There are no departures from the approved tariff classes, tariffs and charging parameters. More detailed information is provided in Section 9.

1.3.4 Queensland Government cap on fee based services

The Queensland Government has historically set maximum price caps to apply to a subset of Ergon Energy's Alternative Control Services through Schedule 8 of the *Electricity Regulation 2006*. Since the Schedule 8 maximum prices are imposed through Queensland legislation, they take precedence over the Alternative Control Services prices approved by the AER.

It is important to note that the prices included in our Pricing Proposal have been derived under the AER's price-setting requirements. These prices, if subject to the Schedule 8 price caps, may be higher than those charged to customers.

1.4 Summary of changes

In accordance with our 2020-25 TSS, the key changes proposed for 2021-22 are:

- Introduction of new SAC Large Basic meter tariffs for residential and business customers. From 1 July 2021 these tariffs will be the default tariffs for basic meter customers consuming more that 100MWh per year. Existing basic meter customers assessed as exceeding 100MWh per year will be reassigned to these new tariffs.
- Introduction of three new Transitional tariffs for eligible SAC Small Business customers where they accessed the corresponding transitional retail tariff at some point in the period 1 July 2017 to 30 June 2020. These tariffs will only be offered in the East pricing zone.

- Described our proposed price-setting methodology for Individually Calculated Customer (ICC) for both standard and non-standard versions of these tariff arrangements.
- The mandated reassignment of existing residential and small business customers with smart metering to the transitional demand tariff on 1 July 2021, as a result of the expiration of the 12 month grace period.[5]
- We have completed a review of network pricing and billing arrangements in order to identify any potential legacy system and tariff arrangements which pre-date the TSS requirement in the NER and have found that there are no legacy tariff arrangements of this nature in Ergon Energy (i.e. Ergon Energy had been fully compliant with the 2017-20 TSS).

Further information about changes to our network tariffs from 1 July 2021 is set out in Section 6.2.

1.5 Structure of this document

The structure of this Pricing Proposal is outlined in Table 1.

Table 1: Pricing Proposal structure

Section	Title	Overview
1	Introduction	Provides an overview of the pricing proposal and the context in which we develop prices, including the relationship with the regulatory framework and our TSS.
2	Tariff classes and tariffs for Standard Control Services	Sets out for the tariff classes, tariffs, tariff structures and tariff assignment policies for our Standard Control Services.
3	Tariff levels for Standard Control Services	Sets out how we have set the prices for Standard Control Services for 2021-22 in accordance with the requirements of the NER and the AER's Distribution Determination.
4	Alternative Control Services	Outlines the tariff classes, tariffs, tariff structures, control mechanisms and tariff assignment policy for Alternative Control Services in accordance with requirements of the NER and the AER's Distribution Determination.
5	Prices for 2021-22 compared to the indicative rates	Outlines any deviations in 2021-22 rates from the indicative rates provided in our 2020-21 Pricing Proposal submission and explains any differences.
6	Changes from the previous regulatory year	Describes the nature and extent of changes from 2020-21.
7	Variations to tariffs within the regulatory year	Sets out the nature of any adjustments or variations to tariffs that could occur during 2021-22 and the basis on which it could occur.
8	Compliance with the Pricing Principles	Demonstrated our compliance with the Pricing Principles set out in the NER.
9	Consistency with the TSS	Demonstrates consistency with our 2020-25 TSS.
	Appendices	Provides additional supporting information, including: • The terms and conditions for load control tariffs • Compliance checklist • Glossary • Confidentiality template

[5] Note that customers with smart metering installed in their premise where the communications functionality has been disabled are proposed to be reassigned to the transitional demand tariff.

We have also provided the following supporting attachments to the AER as part of this Pricing Proposal:

- Attachment 1 – 2021-22 Network Price List
- Attachment 2 – Indicative Pricing Schedule 2021-25
- Attachment 3 – Material Changes 2021-22
- Attachment 4 – Tariff Approval Model 2021-22
- Attachment 5 – Applications for Non-Standard ICC tariff Confidential

2. Tariff classes and tariffs for Standard Control Services

This chapter sets out Ergon Energy's tariff classes, tariffs, charging parameters and tariff assignment policies for Standard Control Services in accordance with our approved TSS for the 2020-25 regulatory control period (NER clause 6.18.2(b)(2) and (3)).

2.1 Tariff classes

Consistent with our TSS, we have categorised Standard Control Services customers into three tariff classes mainly based on the voltage level at which customers are connected to the network. This approach helps ensure customers with broadly similar characteristics, who impose similar costs on the network, are classed together so that they face similar tariff structures. Our tariff classes are listed in the table below.

Table 2: Tariff classes

Tariff class	Eligible customers
Standard Asset Customers (SAC)	All customers connected at LV with installed capacity up to 1,000kVA are classified as SACs. SAC tariffs are based on: • average charges for dedicated connection assets; plus • average charges for use of the shared distribution network, including common and non-system assets.
Connection Asset Customers (CAC)	Customers with a network coupling point at 66 kV, 33 kV, 22 kV, 11 kV and installed capacity above 1,000 kVA who are not assigned to the ICC tariff class are allocated to the CAC tariff class. CAC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • average charges for use of the shared distribution network, including common and non-system assets.
Individually Calculated Customers (ICC)	Customers are assigned to the ICC tariff class if they are coupled to the network at 132 kV, 110 kV, 66 kV or 33 kV and with installed capacity above 10 MVA. Customers may also be assigned to the ICC tariff class if they are coupled to the network at the 132 kV, 110 kV, 66 kV or 33 kV and with installed capacity below 10 MVA where[a]: • A customer has a dedicated distribution system which is quite different and separate from the remainder of our distribution system • A customer is connected at or close to a Transmission Connection Point, or • At the determination of the DNSP, the nature of the customer's connection to the network, and/or usage of the network, make average prices inappropriate • Subject to the Policy set out in Appendix A of our 2020-25 TSS, eligible CAC customers accessing transitional or obsolete retail tariffs and who can demonstrate that they are facing extraordinary customer impact post retirement of the retail tariffs and that this financial impact is directly attributable to their network charges. ICC tariffs allocate residual costs in an equitable and efficient manner by basing this allocation on: • the actual dedicated connection assets utilised by the customer; plus • the customer's specifically identified portion of the shared distribution network utilised for the electricity supply, including common and non-system assets.
Note: a. Some existing customers coupled to the HV network at lower voltage levels will remain assigned to the ICC tariff class for legacy reasons	

It should be noted that, we do not make reference to customer's export load in assigning customers to tariff classes or network tariffs.

2.2 Tariffs and charging parameters

Each tariff class consists of a number of different network tariffs that are established on the same basis as the tariff class. Each tariff comprises a combination of charges that we apply to customers (through their retailer) to recover network costs. The table below sets out the individual tariffs in each tariff class.

Table 3: 2021-22 Network tariffs by tariff class

Tariff class	Customer type	Primary Tariffs	Secondary tariffs
Standard Asset Customers (SAC)	Residential	• Residential Inclining Block (IBT) • Residential Transitional Demand • Residential Demand • Residential Time of Use Energy	• Volume Night Controlled • Volume Controlled
	Small business	• Small Business Inclining Block (IBT) • Small Business Wide Inclining Fixed Tariff (WIFT) • Small Business Transitional Demand • Small Business Demand • Small Business Time of Use Energy • Small Business Primary Load Control • Transitional Network ToU Energy Tariff 1[a] • Transitional Network ToU Energy Tariff 2[a] • Transitional Network Dual Rate Demand Tariff 3[a]	• Volume Night Controlled • Volume Controlled
	Large customer	• Demand Large • Demand Medium • Demand Small • Large Business Time of Use Demand • Seasonal Time of Use Demand[b] • Large Business Primary Load Control • Large Residential Energy *(Residential customer basic >100 MWh per year)* • Large Business Energy *(Business customer basic >100 MWh per year)*	• Large Business Secondary Load Control
	Other	• Unmetered Supply • Solar FiT[b]	
Connection Asset Customers (CAC)		• CAC 66kV • CAC 33kV • CAC 22/11kV Bus • CAC 22/11kV Line • Seasonal Time of Use Demand 11 or 22kV Bus • Seasonal Time of Use Demand 11 or 22kV Line • Seasonal Time of Use Demand 33 or 66kV	
Individually Calculated		• Standard ICC tariff • Non-standard ICC tariff	

Tariff class	Customer type	Primary Tariffs	Secondary tariffs
Customers (ICC)			
Note: a. Introduced on 1 July 2021 and grandfathered immediately b. Grandfathered tariffs (closed to new customers)			

The types of charges used for our Standard Control Services are shown in Table 4.

Table 4: Types of charges for Standard Control Services

Charge	Charging parameters	Application to tariffs
Fixed charge	Represented as a rate ($) per day or rate ($) per day per device.	Applies to all primary tariffs.
Usage (volume) charge	Represented as a rate ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all primary and secondary tariffs.
Block usage (or inclining volume)	Represented as a rate ($) per kWh. Different charges apply to each consumption block. • For IBT Residential the blocks are: 0<1,000kWh; 1,000<6,000kWh and 6,000<100,000kWh • For IBT Business the blocks are: 0<1,000kWh; 1,000<20,000kWh and 20,000<100,000kWh.	Applies to the following tariffs: • Residential IBT • Small Business IBT
Inclining fixed charge	Represented as a rate ($) per day. Different charges apply to 20 MWh per year blocks. There are five blocks: 0<20 MWh per year, 20<40 MWh per year, 40<60 MWh per year, 60<80 per year, and >80 MWh per year.	Applies to the following tariffs: • Small Business WIFT • Small Business ToU Energy
Demand charge	Represented as either a rate ($) per kW or a rate ($) per kVA. Different parameters apply to this charge for different tariffs. Within a tariff structure, demand charge rates can be: • Applied year round (with different peak window rates) • Calculated based on: ○ A single period in the month, or ○ The maximum demand within a peak demand window Some tariff structures include a threshold (the demand charge is only calculated for demands recorded above a particular level).	Applies to all primary tariffs except: • Residential IBT • Small Business IBT • Residential ToU Energy • Small Business ToU Energy • Small Business WIFT • Unmetered Supply, and • any of our load control tariffs.
Excess demand charge	Represented as a rate ($) per excess kVA. It is measured as a single maximum demand outside the peak charging window minus the maximum demand during the peak period in the billing period. Where the maximum demand outside the evening window is less than the highest maximum demand inside the evening window in the billing period, the excess demand charge for that billing period is set to zero.	• The charge applies the SAC Large ToU Demand tariff.
Capacity charge	Represented as a rate ($) per kVA	• The charge applies to the ICC site-specific (Standard and Non-standard) tariffs and CAC any time demand tariffs.

2.3 Tariff assignment and re-assignment process

Procedures for the assignment of new customers and reassignment of existing customers to Standard Control Services tariff classes and tariffs are contained in our 2020-25 TSS, Section 5. Consistent with the NER requirements (clause 6.18.1A(a)(2)), we will comply with these procedures in 2021-22. Additional information is provided in our Network Tariff Guide.

3. Tariff levels for Standard Control Services

This chapter sets out how we have developed our 2021-22 network prices for Standard Control Services in compliance with the regulatory requirements in Chapter 6 of the NER, the AER's revenue determination and our approved TSS.

3.1 Forecast NUOS revenue requirement for 2021-22

In 2021-22, the total revenue that we will need to recover via our network tariffs (NUOS charges) is approximately $1,509 million. This amount includes:

- Distribution Use of System (DUOS) charges, which reflect Ergon Energy's electricity distribution costs,
- Designated Pricing Proposal Charges (DPPC) (or Transmission Use of System (TUOS) charges) which reflect the costs associated with transmission of electricity, and
- Jurisdictional Scheme amounts which Ergon Energy must pay pursuant to State government requirements.

Table 5: Forecast NUOS revenue requirement for 2021-22 ($)

Revenue component	Forecast revenue required for 2021-22
Distribution use of system (DUOS)	1,154,190,142
Transmission use of system (TUOS)	273,109,580
Jurisdictional schemes	82,045,229
Total Network use of system (NUOS)	**1,509,344,951**

3.2 DUOS charges

3.2.1 Calculation of revenue cap for DUOS

As set out in the AER's Distribution Determination (Attachment 13), Ergon Energy's DUOS charges are regulated using a revenue cap. The revenue cap for any given regulatory year is the Total Allowable Revenue (TAR), calculated using the formula set by the AER (refer to Equation 1).

Equation 1: Revenue cap formula[6]

1. $$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i = 1,…,n and j = 1,…,m and t = 1, 2…,5

2. $$TAR_t = AAR_t + I_t + B_t + C_t$$ t = 1, 2...,5

3. $$AAR_t = AR_t \times (1 + S_t)$$ t = 1

4. $$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$$ t = 2

5. $$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$ t = 3, 4, 5

6 All parameters are in nominal terms unless otherwise specified.

where:

TAR_t is the total allowable revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

t is the regulatory year.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the sum of the STPIS (from year t = 3 onwards), demand management incentive scheme, and any other related incentive schemes[7] as they relate to year t-2, applied in year t.

B_t is the sum of annual adjustment factors for year t and includes the true-up for any under or over recovery of actual revenue collected through DUoS charges calculated using the following method:

$$\text{DUoS Under and Overs True} - \text{Up}_\text{t} = -(\text{Opening Balance}_\text{t})(1 + \text{WACC}_\text{t})^{0.5}$$

where:

$\text{DUoS Under and Overs True} - \text{Up}_\text{t}$ is the true-up for the balance of the DUoS unders and overs account in year t.

$\text{Opening Balance}_\text{t}$ is the opening balance of the DUoS unders and overs account in year t.

WACC_t is the approved weighted average cost of capital used in regulatory year t in the DUoS unders and overs account. This WACC figure will be a nominal WACC figure that reflects actual inflation rather than forecast inflation. To calculate this nominal WACC, the real vanilla WACC from the annual update PTRM will be escalated for actual inflation.

C_t is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

X_t is the X factor for each year of the 2020–25 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in AER's Determination Decision (Attachment 3 Rate of return), calculated for the relevant year.

S_t is the s-factor applicable to regulatory year t. This factor will only apply in years t = 1 and 2, with new AER's STPIS guideline providing for a change in the application from year t = 3 onwards.

Table 6 applies the revenue cap formula to calculate our TAR for 2021-22 and demonstrates our compliance with the control mechanism.

[7] This does not reflect those incentive schemes that are calculated and applied through the regulatory determination, such as the capital expenditure sharing scheme (CESS) or efficiency benefit sharing scheme (EBSS).

Table 6: DUOS Total Allowable Revenue for 2021-22

Component	Formula	2021-22 Value
Adjusted annual smoothed revenue requirement (t-1)	AAR_{t-1}	$1,205,053,524
CPI	ΔCPI_t	0.861%
X-factor	X_t	2.035%
S-Factor	S_t	-2.195%
Adjusted annual smoothed revenue requirement (t)	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$	$1,164,549,680
DMIS and DIMIA adjustments	I_t	-$1,046,714
Annual adjustment factors	B_t'	-$9,312,824
Cost pass through amounts	C_t	$0
Total Allowable Revenue	$TAR_t \geq AAR_t + I_t + B_t + C_t$	$1,154,190,142
Proposed revenue		$1,154,190,142
Compliance with revenue cap	***TAR>= Proposed revenue***	**YES**

3.2.2 DUOS unders and overs account

Under a revenue cap form of control, our revenues are adjusted annually to clear any under or over recovery of actual revenue recovered through DUOS charges. This ‘unders and overs’ rebalancing process is undertaken as part of the annual pricing cycle to ensure we recover no more and no less than the TAR approved by the AER for any given year. Under these arrangements there is a lag between the year in which the DUOS under or over recovery occurs and the year in which adjustments are made to prices to ‘clear’ the under or over recovery.

Consistent with the Distribution Determination (Attachment 13), we are required to maintain a DUOS unders and overs account in our annual pricing proposal and provide entries for the most recently completed regulatory year (t-2), the current regulatory year (t-1) and the next regulatory year (t).[8]

The AER also requires that Ergon Energy’s DUOS amounts for the most recently completed regulatory year (t-2) be audited. We believe this requirement is met as the information provided is based on the information submitted and audited as part of the 2019-20 Annual Reporting Regulatory Information Notice (RIN).

[8] Ergon Energy’s Determination decision 2020 to 2025, Attachment 13 – Control Mechanisms, June 2020.

The unders and overs account is presented in Table 7.

Table 7: DUOS unders and overs account ($'000)

Unders/overs account component	2019-20 Year t-2 (actual) $	2020-21 Year t-1 (estimate) $	2021-22 Year t (forecast) $
(A) Revenue from DUOS charges	**$1,317,370,915**	**$1,157,803,000**	**$1,154,190,142**
(B) Less TAR for regulatory year =	**$1,293,364,813**	**$1,205,053,524**	**$1,163,502,966**
+ Adjusted annual smoothed revenues (AARt)	$1,325,455,729	$1,205,053,524	$1,164,549,680
+ Incentive scheme amounts (It)	$0	$0	-$1,046,714
+ Annual adjustments (Bt)	-$32,090,916	$0	$0
+ Cost pass through amount (Ct)	$0	$0	$0
(C) Revenue deliberately under-recovered in year	$0	$0	$0
(A minus B plus C) Under/over recovery of revenue for regulatory year	**$24,006,102**	**-$47,250,524**	**-$9,312,824**
DUOS unders and overs account			
Nominal WACC (per cent)	5.982%	4.285%	3.123%
Opening balance	$28,636,723	$55,063,660	$9,170,731
Interest on opening balance	$1,713,185	$2,359,205	$286,387
Under/over recovery of revenue for regulatory year	$24,006,102	-$47,250,524	-$9,312,824
Interest on under/over recovery for regulatory year	$707,650	-$1,001,609	-$144,294
Closing balance	**$55,063,660**	**$9,170,731**	**$0**

3.2.3 Forecast weighted average revenue

In accordance with clause 6.18.2(b)(4) of the NER, Table 8 sets out the expected weighted average DUOS revenue by tariff class.

Table 8: Expected weighted average DUOS revenue by tariff class

Tariff class	2020-21 Weighted average revenue	2021-22 Weighted average revenue	% Change
ICC	$53,756,321	$50,787,091	-5.52%
CAC	$60,093,677	$61,039,863	1.57%
SAC	$1,020,413,295	$1,042,363,188	2.15%
Total	**$1,134,263,292**	**$1,154,190,142**	1.76%

Note: All amounts are GST exclusive

3.2.4 Tariff class side constraints

For each regulatory year after the first year of a regulatory control period, side constraints apply to the weighted average revenue raised from each tariff class (that is, the expected weighted average revenue from DUOS to be raised from each tariff class in year (t) must not exceed the corresponding expected weighted average revenue from the preceding year (t-1) by more than the permissible percentage determined as per the side constraint formula).[9]

9 Revenue in year t-1 is based on the sum of the prices in year t-1 multiplied by the associated forecast quantities for year t.

The side constraints formula is set out in the AER's Determination Decision (Attachment 13). The table below sets out the maximum permissible percentage increase in the weighted average revenue raised from each tariff class, as determined by the side constraint formula.

Table 9: Calculation of side constraint limit

Component	Formula	Value
CPI	ΔCPI_t	0.861%
X-factor	X_t	0.000%
S-Factor	S_t	-2.195%
DMIS and DIMIA adjustments	I_t	-0.092%
Annual adjustment factors	$B_t^{'}$	1.649%
Cost pass through amounts	C_t	0.000%
Side constraint limit	$\leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t)+I_t^{\prime}+B_t^{\prime}+C_t^{\prime}$	**102.176%**
Note: If X>0, then X will be set equal to zero for the purposes of the side constraint formula.		

As demonstrated in Table 8, the change in weighted average DUOS revenue for all tariff classes is less than the 2.176% permitted by the side constraint rule.

3.3 Designated Pricing Proposal Charges

Under the NER, we are able to recover transmission-related costs associated with:

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to Ergon Energy's distribution network
- payments made to other DNSPs for the supply of distribution services
- avoided transmission charges paid to eligible Embedded generators (EGs).

These costs are recovered from customers through the Designated Pricing Proposal Charges (DPPC), which form part of our network tariffs.

Further information about our transmission costs is provided below.

3.3.1 Transmission costs

DPPC paid to TNSPs (Powerlink)

Powerlink charges Ergon Energy at the Transmission Connection Point level. Their charges comprise both daily supply and variable components, namely:

- Entry/Exit Connection Charge ($/month)
- Capped Customer TUOS Usage Price: Usage Capacity Charge ($/kW/month of nominated demand plus $/kW/month average demand)
- Customer TUOS General Prices: General Energy Charge (c/kWh of historical energy)
- Transmission Customer Common Service Prices: Common Service Energy Charge (c/kWh on historical energy).

Powerlink also charges Ergon Energy for the entry and exit services at three connection points – Stoney Creek, Kings Creek and Oakey Town.

Payment to other DNSPs

In the Toowoomba area, Ergon Energy take supply from Energex at the Postman's Ridge Transmission Connection Point and distribute to a group of customers in the area. This is done on economic grounds. Energex bills Ergon Energy a network service charge for these network services. These charges are forecast each year and are added to the Powerlink charges at our Middle Ridge Transmission Connection Point. This occurs before the allocation process identified above.

In the Mount Isa Zone, we are charged for the use of the unregulated 220 kV network which supplies the Cloncurry township. These costs are passed through to all customers in the Mount Isa Zone via DPPC (TUOS) charges, using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

Avoided TUOS charges

Where we are liable to pay an Avoided TUOS payment to an EG the payment amount is recovered as part of the DPPC charges passed through to all customers. This allocation is premised on the fact that avoided TUOS do not solely impact on the transmission connection point to which the EG is connected but also benefit all customers.

Avoided TUOS payments recognise that energy supplied to the electricity distribution network by the EG would have otherwise been supplied from the transmission network. In accordance with the NER, to calculate the avoided TUOS payments for eligible EGs, we:

(a) Determine the charges for the locational component of prescribed DPPC services that would have been payable by Ergon Energy had the EG not injected any energy at its connection point during that financial year.

(b) Determine the amount by which the charges calculated in (a) exceeds the amount for the locational component of prescribed DPPC services actually payable by Ergon Energy.

(c) Credit the value from (b) to the EG account.

Avoided TUOS payments will generally be remitted in the form of a lump sum payment after 30 June each year. The estimated total amount in avoided TUOS liability to EGs accrued in 2021-22 is included in our DPPC unders and overs account.

3.3.2 DPPC unders and overs account

In accordance with the NER (Clause 6.18.7(a)) and the AER's requirements set out in the Distribution Determination, we are required to maintain a DPPC unders and overs account. Table 10 sets out Ergon Energy's DPPC unders and overs account. The amounts for 2019-20 are based on audited information lodged in our RIN.

Table 10: DPPC unders and overs account

` Unders/overs account component	2019-20 Year t-2 (actual) $	2020-21 Year t-1 (estimate) $	2021-22 Year t (forecast) $
(A) Revenue from designated pricing proposal charges (DPPC)	**$249,447,330**	**$260,125,000**	**$273,109,580**
(B) Less DPPC related payments for regulatory year =	**$256,910,556**	**$258,549,091**	**$268,210,091**
+ DPPC to be paid to Transmission Network Service Provider	$250,802,590	$253,129,669	$262,450,966
+ Avoided TUoS/DPPC payments	$2,532,451	$2,239,469	$2,634,104
+ Inter-distributor payments	$3,575,516	$3,179,952	$3,125,022
(A minus B) Under/over recovery of revenue for regulatory year	**-$7,463,227**	**$1,575,909**	**$4,899,489**
DPPC unders and overs account			
Nominal WACC (per cent)	5.982%	4.285%	3.123%
Opening balance	$1,428,085	-$6,169,707	-$4,824,733
Interest on opening balance	$85,435	-$264,341	-$150,669
Under/over recovery of revenue for regulatory year	-$7,463,227	$1,575,909	$4,899,489
Interest on under/over recovery for regulatory year	-$220,000	$33,406	$75,913
Closing balance	**($6,169,707)**	**($4,824,733)**	**$0**

3.3.3 Recovery of transmission costs

Where administratively efficient, the forecast DPPC will be passed on to customers in the same form of price structure as it is received.

ICC tariffs

For ICCs, our network tariffs preserve the economic signals present in the structure of the DPPC as the charges are based on the relevant transmission connection point. This provides the greatest cost-reflectivity for these customers and is a feasible method for calculating charges since the number of such customers is relatively small.

SAC and CAC tariffs

DPPC cost amounts are allocated to SAC and CAC tariffs proportionally based on a mixture of customer numbers, anytime maximum demands and volumes.

DPPC charges for CAC tariffs are based on average DPPC charges. This provides a degree of cost-reflectivity for this group of customers while recognising the practical difficulties of calculating individual charges for each customer connected at the 11 kV network.

For SAC and CAC customers, Transmission Connection Points are allocated to one of three geographical transmission regions. DPPC charges for this group of customers are calculated based on the combined totals. This has the advantage of simplifying tariffs, while still providing clear DPPC locational signals for these customers.

DPPC charges for our new cost reflective SAC tariffs are recovered from the same tariff structure as DUOS charges (fixed charge, demand charge and volume charges). For our legacy IBT tariffs the DPPC charges are not recovered through the same tariff structures as DUOS charges.

CAC Customers with alternate supplies

For those CAC customers that have a primary and alternate supply (as deemed by Ergon Energy), the following DPPC arrangements apply:

- Primary supply – standard rates and conditions for each charge
- Alternate supply – standard rates and conditions for each charge, except:
  - no DPPC fixed charge applies
  - the authorised demand for the DPPC capacity charge is set at zero.

This means, with the exception of the DPPC fixed charge, alternate supplies to customers are charged at the standard rates (applicable to the voltage of the connection) for all metered quantities. However, with an authorised demand set at zero for the alternate connection, the capacity charge will only apply to the ATMD in any month when a changeover to the alternate supply takes place.

3.4 Jurisdictional scheme amounts

In accordance with clauses 6.18.2(b)(6A) of the NER, our Pricing Proposal must set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. The jurisdictional schemes we are subject to comprise:

- the Solar Bonus Scheme which obligates Ergon Energy to make FiT payments to eligible customers for energy supplied into our distribution network from specific micro-embedded generators[10]
- the energy industry levy covering a proportion of the Queensland Government's funding commitments for the AEMC which, which we are obligated to pay under our Distribution Authority.

The jurisdictional schemes Ergon Energy are subject to have not been amended since the last jurisdictional scheme approval date.

In 2021-22 we will recover the jurisdictional scheme amounts from customers through our network charges.

3.4.1 Jurisdictional scheme payments unders and overs account

As part of the requirements set out in the NER (Clause 6.18.7A) and the AER's Distribution Determination, we are required to provide amounts for the unders and overs relating to jurisdictional schemes. Table 11 provides the forecast 2021-22 balance of Ergon Energy's jurisdictional scheme overs and unders account. The amounts for 2019-20 are based on audited information lodged in our RIN.

[10] The scheme operates under clause 44A of the Electricity Act 1994 (Qld).

Table 11: Jurisdictional scheme amounts unders and overs account

Unders/overs account element	2019-20 Year t-2 (actual) $	2020-21 Year t-1 (estimate) $	2021-22 Year t (forecast) $
(A) Revenue from jurisdictional schemes	**$91,421,931**	**$92,626,000**	**$82,045,225**
(B) Less jurisdictional scheme payments for regulatory year =	**$91,421,931**	**$90,501,361**	**$82,045,229**
+ SBS amount	$91,316,836	$90,384,082	$84,131,244
+ AEMC amount	$114,851	$117,279	$117,279
+ JSA revenue under/over recovery	-$9,756	$0	-$2,203,294
(A minus B) Under/over recovery of revenue for regulatory year	**$0**	**$2,124,639**	**-$4**
Jurisdictional scheme amount unders and overs account			
Nominal WACC (per cent)	5.982%	4.285%	3.123%
Opening balance	$0	$0	$2,169,677
Interest on opening balance	$0	$0	$67,756
Under/over recovery of revenue for regulatory year	$0	$2,124,639	-$2,203,294
Interest on under/over recovery for regulatory year	$0	$45,038	-$34,138
Closing balance	**$0**	**$2,169,677**	**$0**

3.5 Forecast energy and customer numbers

Our network demand, energy and customer number forecasting methodologies are set out in our 2020-21 to 2024-25 Distribution Annual Planning Report[11]. Energy forecasts are prepared at the total network level, at customer category levels and for certain individually calculated network tariffs.

Energy and maximum demand forecasts for major ICC and CAC customers are individually developed. The energy forecast is based on a review of each customer's recent actual consumption history plus any confirmed future operational changes. The forecast demand is either:

- negotiated with the network user and detailed in their connection contract ('contracted demand'), or
- based on a review of actual demand history, with adjustments reflecting up to date customer related information about additions or losses of load.

For new customers a flat usage or similar industry load profile is applied as appropriate until historical data for their connection is available.

For the SAC network user group, forecast energy consumption and customer numbers are based on a combination of econometric forecasts and trend extrapolation.

3.5.1 Forecast underpinning this submission

The forecast energy consumption and customer numbers used for the 2021-22 Pricing Proposal and 2020-21 Pricing Proposal are included in Table 12.

[11] https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

Table 12: Energy consumption and customer number forecasts[12]

	Energy volume (GWh)			Number of customers	
Tariff class	2021-22 Forecast	2020-21 Pricing proposal	2019-20 Actual	2021-22 Forecast	2020-21 Pricing proposal
SAC	8,061	8,063	8,558	765,976	777,786
CAC	1,252	1,381	5,009	179	182
ICC	3,941	4,038		115	108
Total	**13,254**	**13,482**	**13,567**	**766,270**	**778,076**

Notes:

1. 2020-21 Forecast represents forecast volumes and customer numbers used for 2020-21 Pricing Proposal
2. 2019-20 Actual numbers represent numbers reported in 2019-20 EB RIN
3. Customer numbers in the table exclude unmetered customer numbers as these are not used for price setting

The short-term outlook for our volume environment is significantly impacted by the direct and indirect impacts of the Covid-19 pandemic. In a general sense, the pandemic has resulted in residential volumes being higher than otherwise due to more people staying at home to a greater extent that what would have been in the absence of the pandemic. The pandemic induced economic recession has resulted in business volumes being lower than otherwise, particularly in the areas of the economy that are heavily dependent upon overseas tourism. It should be noted that due to the inherent uncertainties associated with the pandemic and the timing and extent of the economic recovery underway, there is a considerable risk (positive and negative) that actual volumes will deviate from forecast in 2021-22. To the extent that these forecasting errors are realised, the revenue cap form of control mechanism will result in future network prices needing to be adjusted to account for the under or over recovery of network revenue. We endeavour to make sure that any adjustments to prices as a consequence of the operation of the revenue cap does not result in unacceptable customer impacts or undermine economic efficiency by creating unnecessary pricing uncertainty and volatility.

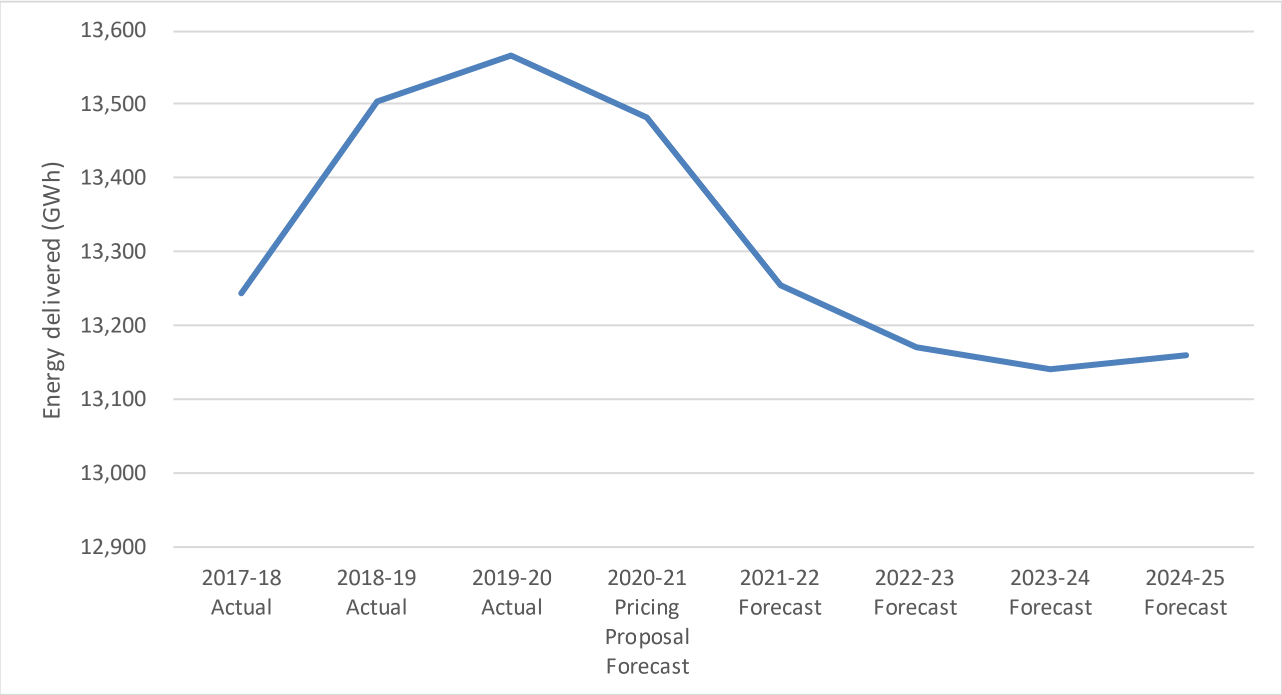
In spite of the economic recession, the uptake of rooftop solar PV has continued with the number of installations in Queensland forecast to grow by 63,740 in 2020-21 and 41,636 in 2021-22. This means that by 2021-22, the total number of customers with solar PV is expected to reach 28%. The

[12] The volume number presented in this table is the anytime forecast volume (both billable and unbillable) which may deviate from the billable volumes depending on the individual uptake of network tariff structures.

rapid growth in solar PV installations in QLD is not only contributing to the underlying decline in volumes in residential sector but is also contributing to a declining trend in minimum demand level.

Over the longer-term, consumption is expected to pick up in 2022-23 as the economic recovery continues and business volumes stabilise. Forecast energy consumption for the remainder of the regulatory control period is provided in Figure 3 below.

Figure 3: Historic and forecast energy consumption



3.6 2021-22 Standard Control Services prices

The proposed network prices for 2021-22 for all Standard Control Services are included in Attachment 1 provided with this Pricing Proposal.

4. Alternative Control Services

Ergon Energy's Alternative Control Services are regulated under a price cap control mechanism. This means that the AER determines our efficient costs and approves a maximum price that we can charge for the service. Chapter 6 of our TSS sets out the methodology we follow to establish our prices for Alternative Control Services, including how we apply the control mechanism formulae set out in the Distribution Determination - Attachment 13.

4.1 Tariff classes

Our tariff classes for Alternative Control Services are differentiated at the highest level according to the classification of services approved in the AER's Distribution Determination. Aligning with the TSS, the Alternative Control Services tariff classes for 2021-22 are set out below.

Table 13: Alternative Control Services tariff classes

Tariff class	Services

Connection services	Services relating to the electrical or physical connection of a customer to the network. Services include:
	• Major customer premises connections
	• Major customer network extensions
	• Connection application and management services:
	  ○ Connection application related services
	  ○ De-energisation and re-energisation services
	  ○ Temporary connections
	  ○ Temporary disconnection and re-connections
	  ○ Supply abolishment
	  ○ Remove or reposition connections
	  ○ Overhead service line replacements
	  ○ Protection and power quality assessments
	  ○ Customer requested change requiring secondary and primary plant studies for safe operation of the network
	  ○ Upgrade from overhead to underground services
	  ○ Rectification of illegal connection or damage to service cables
	  ○ Supply enhancements
	  ○ Power factor corrections
	• Enhanced connection services

Metering services	• Type 6 default metering services
	• Auxiliary metering services including:
	  ○ Meter inspection and investigation
	  ○ Meter reconfiguration
	  ○ Meter alteration
	  ○ Reseal
	  ○ Meter test
	  ○ Meter reading
	  ○ Removal of meter (Type 6)
	  ○ Type 6 non-standard metering data services
	• Provision of service for approved unmetered supplies

Public lighting services	• Public lighting services
	• Auxiliary public lighting services including:
	  ○ Construction of new public light services
	  ○ Provision of unique luminaire glare screening
	  ○ Relocation, rearrangement or removal of existing public light assets
	  ○ Exit fee for the residual asset value of non contributed public lights when the entire assets are replaced before the end of their expected life
	  ○ Emerging public lighting services

Network ancillary services	Customer and third party initiated services related to the common distribution. Services include:

Tariff class	Services
	• Network safety services - Provision of traffic control and safety observer services, Fitting of tiger tails and aerial markers, De-energising for safety, High load escorts • Customer requested planned interruptions • Attendance at customers' premises to perform a statutory right • Customer, retailer or third party requested appointments • Removal/re-arrangement of network assets • Network related property services • Authorisation and approval of third-party service providers design and works • Inspection and auditing services • Sale of approved materials or equipment • Provision of training to third parties for network related access • Security (watchmen) lights • Non-standard network data requests • Customer requested provision of electricity network data • Third party funded network alternations

4.2 Tariffs and charging parameters

In accordance with clause 6.18.2(b)(2) of the NER, Attachment 1 of our Pricing Proposal sets out the proposed tariffs for Alternative Control Services which have been specified in our TSS.

Clause 6.18.2(b)(3) of the NER requires that our Pricing Proposal sets out the charging parameters utilised to calculate the charges for Alternative Control Services and elements of service to which each charging parameter relates. These are presented in Table 14.

Table 14: Pricing arrangements for Alternative Control Services

Tariff classes and Services	Pricing arrangements	Charging parameter
Connection services – Services relating to the electrical or physical connection of a customer to the network		
Major customer - Premises connections	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Major customer - Network extensions	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Connection application and management services	Fixed charge and in some cases Quoted price	Fixed rate ($) per service. The rate varies depending on the service requested. Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Enhanced connection services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Network ancillary services – Customer and third party initiated services related to the common distribution service		
Network safety services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Customer requested planned interruptions	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.

Tariff classes and Services	Pricing arrangements	Charging parameter
Attendance at customers' premises to perform a statutory right	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.
Customer, retailer or third party requested appointments	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Removal/rearrangement of network assets	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Network related property services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Authorisation and approval of third-party service providers design/ works	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Inspection and auditing services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Sale of approved materials or equipment	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Provision of training to third parties for network related access	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Security (watchman) lights	Quoted price - for installation service costs Fixed charge - for the maintenance, operation and replacement of the assets	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service. Fixed rate ($) per day per light - Within the tariff structure, daily charges differ by: • light type (conventional or LED) and • the size of the lamp/luminaire.
Non-standard network data requests	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Customer requested provision of electricity network data	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Third party funded network alternations	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Metering services		
Type 6 default metering services	Fixed price	Metering services charge: fixed ($) per day per tariff. Metering service charges differ by: • The type of metering service (primary, controlled load, solar PV), and • The type of cost recovery (capital, non-capital).
Auxiliary metering services	Fixed price, and in some cases Quoted price	Fixed rate ($) per service. The rate varies depending on the service requested. Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Provision of services for approved unmetered supplies	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Public Lighting Services		

Tariff classes and Services	Pricing arrangements	Charging parameter
Public lighting services	Fixed price	Public lighting charge: Fixed rate ($) per day per light. Daily public lighting charges differ by: • the ownership status (owned and operated, or Gifted and operated), • the size of the lamp (major or minor), and • technology (conventional vs LED).
Auxiliary public lighting services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.

4.3 Tariffs assignment process

Detailed procedures for the assignment and reassignment of customers to Alternative Control Services tariff classes and tariffs are contained in our TSS (refer to Chapter 7). Consistent with the NER requirements (clause 6.18.1A(a)(2)), we will comply with these procedures in 2021-22.

Similar to the tariff class membership requirement for Standard Control Services, Alternative Control Services customers will not receive the service prior to being allocated to the appropriate tariff class. For ACS, customers or customers' retailers self-assign to a tariff class when requesting the service they require.

In accordance with our TSS, we generally do not initiate tariff class re-assignments for ACS. However, there are some circumstances where a field crew attends a site and the scope of work does not match the service order or work request. This may mean a different service type and/or tariff class may be more appropriate. In these instances, the job is generally returned as not completed and a new service order or work request would need to be submitted. Consequently, a new tariff class assignment, rather than reassignment, would occur.

4.4 Pricing methodology

4.4.1 Type 6 default metering services

For our Type 6 Default Metering Services we have applied a limited building block approach to determine the revenue required over 2020-25 regulatory control period. This allowable revenue is then converted into metering service charges that are each subject to a price cap for the regulatory control period.

In years 2 to 5 of the regulatory control period (2021-2025), the prices are adjusted for inflation and the X factor, using the price cap formula in Equation 2.

Equation 2: Price cap formula for Type 6 default metering services, public lighting services and fee-based services

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^t is the cap on the price of service i in year t

p_i^{t-1} is the cap on the price of service i in year t-1

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1.

X^t_i is the X-factor for service i in year t.

A^t_i is an adjustment factor likely to include, but not limited to, adjustments for residual charges when customers choose to replace assets before the end of their economic life.

Type 6 default metering services include the maintenance, reading, data services, and the recovery of capital costs related to Type 6 meters. Type 6 default metering service charges are applied through a daily metering services charge. These charges are split into two components:

- a non-capital (operating expenditure) component that is applied to customers with legacy Type 6 meters and continues to apply until a customer's meter is replaced with an unregulated Type 1-4 meter.
- a capital component that is applied to customers connected prior to 1 July 2015, to recover the remaining capital cost related to legacy Type 6 meters. This charge will continue to apply until the depletion of Ergon Energy's remaining metering asset base.

Consistent with our TSS, we apply the following types of Type 6 default metering charges to recover the annual revenue requirement from customers:

- A metering service charge for the primary metering service
- A supplementary charge for each secondary controlled load, and
- A supplementary charge for solar PV.

Table 15: Type 6 Default Metering Service tariffs

Tariff group	Tariffs	Charging parameters
Primary tariff	Non-capital	Fixed rate ($) per day
	Capital	
Load control	Non-capital	
	Capital	
Solar PV	Non-capital	
	Capital	

4.4.2 Public lighting services

For public lighting services, the limited building block approach is used to determine our revenue requirements during 2020-25. This allowable revenue is then converted into public lighting service charges that are each subject to a price cap for the regulatory control period.

In years 2 to 5 of the regulatory control period (2021-2025), the prices are adjusted for inflation and the X factor, using the price cap formula in Equation 2.

In accordance with our TSS, for the 2020-25 regulatory control period Network Public Lighting (NPL) charges reflect whether:

- The public lighting services are located on minor or major roads
- The assets have been funded by us or by the customer, i.e. NPL1 "Ergon Energy owned and operated" versus NPL2 "customer gifted and operated by Ergon Energy", NPL4 for assets where customers fund the replacement of the NPL1 luminaire and lamp to LED, but where the associated pole and cabling are legacy and non-contributed assets, and
- The type of public lighting technology (i.e. conventional or LED).

The public lighting tariffs offered in 2021-22 are set out in the table below.

Table 16: Public lighting tariffs

Tariff group	Conventional Lights tariffs	LED specific tariffs	Charging parameters
NPL1 - Minor	NPL1C Minor – funded by Ergon Energy	NPL1L Minor – Funded by Ergon Energy	Fixed rate ($) per day per light
NPL1 - Major	NPL1C Major – funded by Ergon Energy	NPL1L Major – Funded by Ergon Energy	
NPL2 - Minor	NPL2C Minor – Funded by Council	NPL2L Minor – Funded by Councils	
NPL2 - Major	NPL2C Major – Funded by Council and DTMR	NPL2L Major – Funded by Councils and DTMR	
NPL4 - Minor	N/A	NPL4 Minor – Funded by Councils	
NPL4 - Major	N/A	NPL4 Major – Funded by Councils	

4.4.3 Other Alternative Control Services

In accordance with the AER's Determination Decision, a cost build up approach was used to determine the prices for other services classified as ACS. Pricing arrangements for these services are either fee-based or quoted depending on the type of service.

Fee-based services

The prices for fee-based services are set in accordance with specified service assumptions due to the standardised nature of the services. Fee-based services are determined via a cost build up approach at the individual service level and relate to activities undertaken by us at the request of customers or their agents. The costs for these activities can be directly attributed to customers and service-specific prices can be charged.

During the first year of the regulatory control period (i.e.2020-21), the prices for fee-based services are determined using the AER's approved cost build-up formula. In years 2 to 5 of the regulatory control period (2021-2025), the prices for fee-based services are adjusted annually for inflation and the X factor, using the price cap formula in Equation 2.

Quoted services

Prices for quoted services are determined at the time the customer makes an enquiry and therefore reflect the individual nature and scope of the requested service which cannot be known in advance. The indicative prices for quoted services are determined using the AER's approved price cap formula below.

Equation 3: Price cap formula for quoted services

Price = Labour + Contractor Services + Materials

Where:

- Labour (including on costs and overheads) - consists of all labour costs directly incurred in the provision of the service which may include, but is not limited to, labour on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.
- Contractor services (including overheads) - reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service.
- Materials (including on costs and overheads) - reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

4.5 Annual cost input changes

In accordance with the AER's Distribution Determination, the annual changes to cost inputs used in calculating prices for our Alternative Control Services are required to be submitted to the AER for approval in our Pricing Proposal.

- Type 6 default metering services, Public lighting services and Fee-based services: For years 2 to 5 (2021-25) of the regulatory control period, the prices will be escalated annually for CPI and X factor using AER's approved rates.
- Quoted services: The hourly labour rates approved by the AER for 2020-21 will be escalated by $(1+\Delta CPI_t)(1-X_t^i)$ and utilised for the purpose of Equation 3.

The CPI and X factors used for setting 2021-22 prices are provided in the table below.

Table 17: 2021-22 values for CPI and X -factors

Component	2021-22 value
CPI:	0.8606%
X factors:	
Default metering services	0.0000%
Public lighting	0.0000%
Security lighting	-0.7434%
General Fee-based services	-0.9825%
Type 6 meter installation - urban/short rural	-0.5618%
Type 6 meter installation - long rural/remote	-0.7112%

X-Factors have been set in accordance with the AER's Distribution Determination – Attachment 15: Alternative Control Services

4.6 2021-22 Alternative Control Services prices

The proposed prices for 2021-22 for all Alternative Control Services tariffs are provided in Attachment 1 with our Pricing Proposal.

5. Prices for 2021-22 compared to the indicative prices

The NER obligation (Clause 6.18.2(b)(7A)) requires us to demonstrated how each proposed tariff is consistent with the indicative pricing levels (as set out in the indicative pricing schedule) and explain material differences. To satisfy this regulatory requirement we have included a comparison between the proposed prices for 2021-22 and the indicative 2021-22 price submitted with our 2020-21 Pricing Proposal submission. This price comparison is included in Attachment 3 provided with this Pricing Proposal. Further explanation is provided below.

5.1 Differences in Standard Control Services pricing levels

Deviations from the indicative prices for 2021-22 are due to:

- updates to allowed revenue to reflect actual 2019-20 revenue over recovery
- slight rebalancing of revenue across our tariff suite based on the updated rates, driven by the change in our revenue requirement
- updates to approved jurisdictional scheme amounts (Solar Bonus Scheme and AEMC levy) and DPPC amounts based on the latest forecasts.

With respect to materiality, we have referenced an increase of greater than 15 per cent in an individual rate/charge. As shown in Attachment 3, a limited number of tariffs and charging parameters met these criteria. These include:

- CAC tariffs:
  - DUOS volume charges have increased across tariffs in line with updated customer information and revenue requirement.
- SAC tariffs:
  - Our DUOS volume charges, as the residual cost component, have changed due to the update in forecast customer uptake and energy consumption across our tariff suite.
  - We have adjusted our tariffs relativities in accordance with the annual transition constraints outlined in our TSS (Section 2.4.4).
  - Jurisdiction scheme charges have decreased due to a decrease in jurisdictional scheme amounts that we are required to recover.
  - DPPC volume rates have increased, due to the increase in Powerlink's transmission charges.

5.2 Differences in Alternative Control Services pricing levels

Any differences between the indicative 2021-22 prices for Alternative Control Services (included as part of the 2020-21 Pricing Proposal submission) and the 2021-22 prices included in this Pricing Proposal are reflective of the difference between the forecast CPI and actual CPI.

5.3 Updated indicative pricing levels

Our latest estimates of indicative Standard Control Services and Alternative Control Services prices for the remainder of the regulatory control period (2021-25) are provided in Attachment 2 of our Pricing Proposal. These prices are based on tariff structures detailed in our TSS.

6. Changes from the previous regulatory year

The NER obligation (Clause 6.18.2(b)(8) requires us to describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable distribution determination.

6.1 Changes to the revenue requirement

Table 18 below outlines changes in our revenue requirement between 2020-21 and 2021-22.

Table 18: Summary of revenue adjustments

Component	Unit	2020-21 values	2021-22 values	Reason for change
CPI	%	1.840%	0.861%	Adjustment as per information published by the ABS – CPI All Groups, Average of Eight Capital Cities from the December 2019 quarter to the December 2020 quarter.
X Factor	%	N/A	2.035%	X-factor updated in PTRM
STPIS	$m	$26.45	$0.00	The applicable S-factor for the year is 0%. It has been adjusted to reflect the previous year's S-factor.
DUOS under/over recovery	$m	($28.02)	($9.31)	DUOS over recovery to be returned to customers in 2021-22
DUOS	$m	$1,177.04	$1,154.19	1.9% decrease in the Total Allowable Revenuue between 2020-21 and 2021-22 in accordance with the AER's Final Determination.
Jurisdictional schemes	$m	$90.50	$82.05	9% decrease between 2020-21 and 2021-22 in jurisdictional scheme amounts.
DPPC (TUOS)	$m	$259.38	$273.11	5.29% increase in Powerlink charges between 2020-21 and 2021-22 in accordance with the AER's Final Determination.

Note:
Above figures represented to 2 decimals places for presentation purposes.

6.2 Network tariff changes for Standard Control Services

In accordance with the AER's Determination Decision and our approved 2020-25 TSS, we will implement the following changes to our network tariffs from 1 July 2021:

Changes affecting SAC customers with consumption <100MWh per year

- All customers with an installed smart meter prior to 1 July 2020 will be reassigned from the IBT or WIFT tariff to a transitional demand tariff on 1 July 2021. These smart meter customers will not be allowed to opt in back to their legacy tariffs.

  For existing customers that received a smart meter after 1 July 2020 due to reasons not initiated by the customer (e.g. end of life replacement), we will continue to offer a 12 month grace period from the date of the meter replacement prior to reassigning the customer to a transitional demand tariff.
- We have introduced three new optional tariffs available to existing SAC Small business customers where they accessed the corresponding transitional retail tariff (Gazetted

Transitional Retail Tariff 62, 65 and 66) at some point in the period 1 July 2017 to 30 June 2020. These tariffs will only be offered in the East pricing zone.

Changes affecting SAC customers with consumption >100MWh per year

- We have introduced two new tariffs (Residential and Business) for customers with basic meters and consumption above 100MWh per year. From 1 July 2021, all customers with basic metering and annual consumption exceeding 100MWh will be reassigned to these new tariffs upon their next meter read.

Our TSS provides further information and the rationale for the changes noted above.

2021-25 Price setting strategy for three new SAC Small Business Transitional Tariffs

The approved TSS sets out that from 1 July 2021 three optional network transitional TOU tariffs will be made available to SAC Small customers in the East pricing zone who are or have been on a revoked retail transitional tariff at some point in the period 1 July 2017 to 30 June 2020. The reason for introducing these tariffs stems from the feedback received during stakeholder engagement on the TSS. Being transitional in nature, it is therefore important to set out a clear pathway for these transitional tariffs while at the same time taking into account customer impact.

Considering the high stakeholder interest and linkages between network and retail tariffs, we consider that that such a strategy should be clearly articulated and transparently communicated to stakeholders and customers to enable all parties to prepare ultimately for the retirement of these transitional tariffs.

In terms of overarching principles, we propose that:

- the indicative rates for the transitional TOU tariffs included in the 2020-25 TSS are used as the point of reference and foundation for the proposed rate setting strategy.
- A 10% increase above the TSS's indicative rates be applied in the first year of introducing the transitional TOU tariffs (i.e. 2021-22).
- A 6% annual increase be applied in subsequent years until 30 June 2025.

It should be noted that these are optional tariffs, therefore eligible customers which appear to be worse off in the first year of introducing the new transitional tariffs would not experience an adverse bill impact as these customers would be expected to remain on their current/legacy network tariff.

6.3 Alternative Control Services changes

There are no changes from the previous regulatory year in any aspects of our 2021-22 proposal for Alternative Control Services.

7. Variations to tariffs within the regulatory year

Clause 6.18.2(b)(5) of the NER requires that a pricing proposal set out the nature of any variations or adjustments to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

7.1 Standard Control Services tariff adjustments

We propose to adjust to our ICC or CAC network tariffs in circumstances where an ICC or CAC customer advises us that they intend to alter their demand or connection characteristics during the course of the year. In these circumstances, we will recalculate the customer's site-specific charge with the adjustment applied to the:

- daily fixed charging parameter for CAC customers; and
- fixed, capacity, demand and volume charging parameters for ICC customers.

In accordance with our TSS, these adjustments are required to ensure these tariffs remain cost reflective. Any changes in site-specific charges for CAC or ICC customers will occur at the next network bill (noting that the published non-site specific demand and volume rates will continue to apply to CAC customers in accordance with this Pricing Proposal).

When new tariffs are created in the case of new ICC or CAC connections during 2021-22, the price setting mechanism will be in line with the methodology set out in our TSS and this Pricing Proposal and rates will reflect the customer's connection characteristics and the specifically identified portion of the shared distribution network utilised for the electricity supply.

There are no other variations or adjustments proposed to be made to Standard Control Services tariffs during the 2021-22 regulatory year.

7.2 Alternative Control Services tariff adjustments

With the exception of the application of Schedule 8 of the *Electricity Regulation 2006* to a number of our Alternative Control Services, there are no other variations or adjustments proposed to be made to Alternative Control Services tariffs during the 2021-22 regulatory year.

8. Compliance with the Pricing Principles

This section sets out the manner in which our tariffs have been set to ensure they comply with each of the pricing principles in Clause 6.18.5 of the NER.

8.1 Standard Control Services

8.1.1 Revenue lies between avoidable and stand-alone costs

In accordance with the Pricing Principles (clause 6.18.5(e) of the NER), the revenue expected to be recovered from each tariff class should lie on or between the bounds of stand-alone and avoidable costs. By requiring revenue from each tariff class to lie between stand alone and avoidable costs, the regulatory framework ensures that each class of customers will be allocated the efficient costs of the network services they require. Table 19 below demonstrates our compliance with the requirement of clause 6.18.5(e) of the NER.

Table 19: Comparison of 2021-22 Expected DUOS revenue vs Avoidable and Standalone costs

Tariff class	Avoidable cost	2021-22 Forecast DUOS revenue	Stand Alone cost
SAC	$573,288,064	$1,042,363,188	$1,051,700,842
CAC	$57,810,661	$61,039,863	$757,750,970
ICC	$48,710,068	$50,787,091	$361,046,167

8.1.2 Tariffs to be based on long run marginal cost

The pricing principles in the NER require each tariff to be based on the LRMC of providing the service to which it relates to the retail customers assigned to that tariff. The method of calculating and applying LRMC must have regard to a number of considerations specified in clause 6.18.5(f) of the NER.

In our tariff-setting for 2021-22 we have applied the approach to LRMC detailed in our TSS. This approach includes:

- Incorporating the LRMC values in the demand charge parameter of the demand-based tariffs as it is considered the most suitable mechanism to signal the cost of future network augmentation. For the tariffs without a demand charge parameter, LRMC has been allocated to the 'peak' usage charge of time-of-use usage/volumetric tariffs.
- Gradually aligning the demand charge or 'peak' usage change with our LRMC estimates.
- Incorporating a muted LRMC signal in our Transitional Demand tariffs for SAC Small customers compared to the standard demand tariffs. This is intended to allow customers to adjust to tariffs they may not be familiar with and to mitigate the potential for network charge impact.
- Our 'legacy tariffs': These tariffs have been in place for many years and, therefore, do not reflect the LRMC signal inherent in the demand or time of use energy-based tariff structures.

Table 20 provides Ergon Energy's LRMC estimates for each demand and 'peak' usage charge parameter per tariff. We will adjust the demand and 'peak' charges where we significantly deviate from the LRMC estimate.

Table 20: LRMC estimates and application in tariff setting

Pricing zone	Tariff name	NTC	Charge	LRMC Voltage Level	Annual LRMC 2020-21 TSS		Annual LRMC 2021-22		100% LRMC charge	Percentage of LRMC applied	2021-22 Charge
				Voltage	$/kW	$/kVA	$/kW	$/kVA	$/kW, kVA, kWh	%	$
East	CAC 66kV	EC66	Actual Demand kVA	Sub-Transmission		75.822		76.475	6.373	47.3%	3.014
East	CAC 33kV	EC33	Actual Demand kVA	Sub-Transmission		75.822		76.475	6.373	49.0%	3.122
East	CAC 22/11kV Bus	EC22B	Actual Demand kVA	High Voltage Bus		127.024		128.117	10.676	35.5%	3.786
East	CAC 22/11kV Line	EC22L	Actual Demand kVA	High Voltage Line		150.840		152.138	12.678	60.2%	7.636
East	Seasonal TOU Demand CAC Higher Voltage (33-66kV)	EC66TOU	Actual Demand Charge Peak	Sub-Transmission		75.822		76.475	25.492	46.0%	11.728
East	Seasonal TOU Demand CAC 22/11kV Bus	EC22BTOU	Actual Demand Charge Peak	High Voltage Bus		127.024		128.117	42.706	103.6%	44.225
East	Seasonal TOU Demand CAC 22/11kV Line	EC22LTOU	Actual Demand Charge Peak	High Voltage Line		150.840		152.138	50.713	142.3%	72.184
East	Large ToU Demand	ELTOUD	Actual Demand Peak kVA	Low Voltage		226.142		228.088	19.007	63.7%	12.103
East	Demand Large	EDLT	Actual Demand kW	Low Voltage	251.269	226.142	253.431		21.119	73.0%	15.407
East	Demand Large	EDLT	Actual Demand kVA	Low Voltage		226.142		228.088	19.007	73.0%	13.875
East	Demand Medium	EDMT	Actual Demand kW	Low Voltage	251.269	226.142	253.431		21.119	89.9%	18.995
East	Demand Medium	EDMT	Actual Demand kVA	Low Voltage		226.142		228.088	19.007	90.0%	17.107
East	Demand Small	EDST	Actual Demand kW	Low Voltage	251.269	226.142	253.431		21.119	111.9%	23.639
East	Demand Small	EDST	Actual Demand kVA	Low Voltage		226.142		228.088	19.007	112.0%	21.288
East	Seasonal ToU Demand	ESTOUDC	Actual Demand Peak kW	Low Voltage	251.269	226.142	253.431		64.203	98.5%	63.271
East	Small Business Demand	EBDEM	Peak Demand kW	Low Voltage	251.269	226.142	253.431		21.119	20.0%	4.225
East	Small Business Transitional Demand	EBTDEM	Peak Demand kW	Low Voltage	251.269	226.142	253.431		21.119	1.7%	0.353
East	Small Business ToU Energy	EBTOUE	Volume Evening kWh	Low Voltage	251.269	226.142	253.431		0.76302	32.3%	0.24679
East	Residential Demand	ERDEM	Peak Demand kW	Low Voltage	251.269	226.142	253.431		21.119	20.3%	4.297
East	Residential Transitional Demand	ERTDEM	Peak Demand kW	Low Voltage	251.269	226.142	253.431		21.119	4.2%	0.880
East	Residential ToU Energy	ERTOUE	Volume Evening kWh	Low Voltage	251.269	226.142	253.431		0.60765	20.8%	0.12665
West	CAC 66kV	WC66	Actual Demand kVA	Sub-Transmission		160.994		162.379	13.532	52.6%	7.120
West	CAC 33kV	WC33	Actual Demand kVA	Sub-Transmission		160.994		162.379	13.532	136.3%	18.445
West	CAC 22/11kV Bus	WC22B	Actual Demand kVA	High Voltage Bus		305.156		307.782	25.649	122.1%	31.317
West	CAC 22/11kV Line	WC22L	Actual Demand kVA	High Voltage Line		590.291		595.371	49.614	63.1%	31.317
West	Seasonal TOU Demand CAC Higher Voltage (33-66kV)	EC66TOU	Actual Demand Charge Peak	Sub-Transmission		160.994		162.379	54.126	54.5%	29.512
West	Seasonal TOU Demand CAC 22/11kV Bus	EC22BTOU	Actual Demand Charge Peak	High Voltage Bus		305.156		307.782	102.594	122.1%	125.269
West	Seasonal TOU Demand CAC 22/11kV Line	EC22LTOU	Actual Demand Charge Peak	High Voltage Line		590.291		595.371	198.457	88.4%	175.376
West	Large ToU Demand	WLTOUD	Actual Demand Peak kVA	Low Voltage		659.842		665.521	55.460	62.8%	34.811
West	Demand Large	WDLT	Actual Demand kW	Low Voltage	733.158	659.842	739.467		61.622	94.5%	58.247
West	Demand Large	WDLT	Actual Demand kVA	Low Voltage		659.842		665.521	55.460	94.5%	52.422
West	Demand Medium	WDMT	Actual Demand kW	Low Voltage	733.158	659.842	739.467		61.622	110.7%	68.232
West	Demand Medium	WDMT	Actual Demand kVA	Low Voltage		659.842		665.521	55.460	110.7%	61.409
West	Demand Small	WDST	Actual Demand kW	Low Voltage	733.158	659.842	739.467		61.622	105.8%	65.181
West	Demand Small	WDST	Actual Demand kVA	Low Voltage		659.842		665.521	55.460	105.8%	58.663
West	Seasonal TOU Demand	WSTOUDC	Actual Demand Peak kW	Low Voltage	733.158	659.842	739.467		187.332	87.2%	163.346
West	Small Business Demand	WBDEM	Peak Demand kW	Low Voltage	733.158	659.842	739.467		61.622	16.9%	10.412
West	Small Business Transitional Demand	WBTDEM	Peak Demand kW	Low Voltage	733.158	659.842	739.467		61.622	1.4%	0.867
West	Small Business ToU Energy	WBTOUE	Volume Evening kWh	Low Voltage	733.158	659.842	739.467		2.31478	27.3%	0.63227
West	Residential Demand	WRDEM	Peak Demand kW	Low Voltage	733.158	659.842	739.467		61.622	27.6%	17.032
West	Residential Transitional Demand	WRTDEM	Peak Demand kW	Low Voltage	733.158	659.842	739.467		61.622	2.8%	1.703
West	Residential ToU Energy	WRTOUE	Volume Evening kWh	Low Voltage	733.158	659.842	739.467		1.65253	30.4%	0.50245
Mt Isa	Large ToU Demand	MLTOUD	Actual Demand Peak kVA	Low Voltage		103.056		103.943	8.662	137.5%	11.912
Mt Isa	Demand Large	MDLT	Actual Demand kW	Low Voltage	114.507	103.056	115.492		9.624	108.7%	10.460
Mt Isa	Demand Large	MDLT	Actual Demand kVA	Low Voltage		103.056		103.943	8.662	108.7%	9.414
Mt Isa	Demand Medium	MDMT	Actual Demand kW	Low Voltage	114.507	103.056	115.492		9.624	139.4%	13.420
Mt Isa	Demand Medium	MDMT	Actual Demand kVA	Low Voltage		103.056		103.943	8.662	139.4%	12.078
Mt Isa	Demand Small	MDST	Actual Demand kW	Low Voltage	114.507	103.056	115.492		9.624	153.4%	14.766
Mt Isa	Demand Small	MDST	Actual Demand kVA	Low Voltage		103.056		103.943	8.662	153.4%	13.290
Mt Isa	Seasonal TOU Demand	MSTOUDC	Actual Demand Peak kW	Low Voltage	114.507	103.056	115.492		29.258	214.9%	62.879
Mt Isa	Small Business Demand	MBDEM	Peak Demand kW	Low Voltage	114.507	103.056	115.492		9.624	37.1%	3.566
Mt Isa	Small Business Transitional Demand	MBTDEM	Peak Demand kW	Low Voltage	114.507	103.056	115.492		9.624	4.9%	0.476
Mt Isa	Small Business ToU Energy	MBTOUE	Volume Evening kWh	Low Voltage	114.507	103.056	115.492		0.35233	52.5%	0.18491
Mt Isa	Residential Demand	MRDEM	Peak Demand kW	Low Voltage	114.507	103.056	115.492		9.624	37.6%	3.616
Mt Isa	Residential Transitional Demand	MRTDEM	Peak Demand kW	Low Voltage	114.507	103.056	115.492		9.624	12.1%	1.167
Mt Isa	Residential ToU Energy	MRTOUE	Volume Evening kWh	Low Voltage	114.507	103.056	115.492		0.24642	31.5%	0.07765

8.1.3 Least distortionary recovery of residual costs

The pricing principles in the NER (Clause 6.18.5(g)(1),(2) and (3)) provide that we structure our tariffs in a manner that enables the recovery of our 'residual' costs while minimising distortions to LRMC-based signals.

In establishing the 2021-22 network tariffs, we confirm that it has been necessary to allocate residual costs in order to recover the portion of the revenue cap that that could not be fully recovered through the LRMC-based charging parameters. This means that we have to recover the revenue shortfall through the fixed, volume, off-peak and capacity parameters. Residual recovery within each customer group has been based on selecting combinations that minimise distortion of the LRMC signal.

8.1.4 Consideration of customer impacts

We have been mindful of retail customer impacts when determining the manner in which, and speed with which, different tariffs should reflect the pricing principles contained in clauses 6.18.5(e) to (g) of the NER.

Our 2020-25 TSS describes the measures we have taken to manage the impact of annual change to DUOS rates on individual customers, whilst moving toward a greater cost reflectivity over the 2021 to 2025 period. These measures include:

- Rebalancing components within tariffs to progressively transition the LRMC components of charges towards full LRMC recovery and making small adjustments to comparative attractiveness of the tariff options available to customers, within the overall customer impact ceiling.
- Providing optional time-of-use energy tariffs to SAC Small customers who do not wish to be on a demand tariff.
- Granting a 12-month grace period for existing residential and small business customers that receive a smart meter due to end-of-life reasons before they are re-assigned to the cost reflective transitional demand tariffs.

In establishing the 2021-22 tariffs, we have continued to apply these measures.

The tables below present our customer impact analysis for 2021-22 for SAC customers and demonstrate that residential and small business customers with smart meters are expected to experience a slight increase in their network charges (<2%), while basic metering customer will experience a modest increase (between 0.6% and 6% for legacy IBT tariffs) in 2021-22 compared with 2020-21 network charges. This change in network rates is mainly driven by the forecast decrease in energy consumption resulting from the economic impacts of COVID-19 pandemic and increases in Powerlink's transmission charges.

Table 21: Customer impact for average customers on SAC tariffs

Nominal ($) – NUOS change

East pricing zone

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2020-21 NUOS ($)	2021-22 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - East						
Residential IBT East (ERIB)	3.93	4,886	814.55	837.71	23.16	2.8%
Residential Demand East (ERDEM)	3.93	4,886	845.45	852.34	6.89	0.8%
Residential Transitional Demand East (ERTDEM)	3.93	4,886	802.96	816.07	13.12	1.6%
Residential ToU Energy East (ERTOUE)	3.93	4,886	814.90	833.54	18.65	2.3%
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.						
Small Business (<100MWh pa) - East						
Small Business IBT East (EBIB)	6.78	7,457	1,111.86	1,174.66	62.79	5.6%
Small Business Demand East (EBDEM)	6.78	7,457	1,250.62	1,267.36	16.74	1.3%
Small Business Transitional Demand East (EBTDEM)	6.78	7,457	1,110.25	1,123.54	13.29	1.2%
Small Business ToU Energy East (EBTOUE)	6.78	7,457	1,135.54	1,146.45	10.91	1.0%
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.						
Large Business (>100MWh pa) - East						
Demand Small East (EDS)	53.17	207,904	24,269.38	24,852.06	582.68	2.4%
Demand Medium East (EDM)	186.59	737,463	76,583.95	79,186.71	2,602.76	3.4%
Demand Large East (EDL)	480.86	1,762,206	175,276.37	180,931.37	5,655.00	3.2%
Large Business Time-of-Use Demand East (ELTOUD)	480.86	1,762,206	169,516.58	177,591.68	8,075.10	4.8%

West pricing zone

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2020-21 NUOS ($)	2021-22 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - West						
Residential IBT West (WRIB)	4.23	4,888	1,838.03	1,882.50	44.47	2.4%
Residential Demand West (WRDEM)	4.23	4,888	1,981.88	2,011.11	29.23	1.5%
Residential Transitional Demand West (WRTDEM)	4.23	4,888	1,858.53	1,883.00	24.47	1.3%
Residential ToU Energy West (WRTOUE)	4.23	4,888	1,799.40	1,832.25	32.85	1.8%
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.						
Small Business (<100MWh pa) - West						
Small Business IBT West (WBIB)	6.24	7,514	2,467.88	2,548.97	81.10	3.3%
Small Business Demand West (WBDEM)	6.24	7,514	2,665.38	2,692.15	26.76	1.0%
Small Business Transitional Demand West (WBTDEM)	6.24	7,514	2,482.93	2,512.70	29.77	1.2%
Small Business ToU Energy West (WBTOUE)	6.24	7,514	2,415.64	2,456.39	40.75	1.7%
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.						
Large Business (>100MWh pa) - West						
Demand Small West (WDS)	49.48	183,807	49,475.64	50,489.39	1,013.75	2.0%
Demand Medium West (WDM)	168.43	499,372	190,849.82	193,457.47	2,607.66	1.4%
Demand Large West (WDL)	567.92	2,174,693	501,014.44	512,800.06	11,785.62	2.4%
Large Business Time-of-Use Demand West (WLTOUD)	567.92	2,174,693	488,879.92	514,300.47	25,420.55	5.2%

Mount Isa

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2020-21 NUOS ($)	2021-22 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - Mt Isa						
Residential IBT Mt Isa (MRIB)	4.24	4,878	695.22	698.38	3.16	0.5%
Residential Demand Mt Isa (MRDEM)	4.24	4,878	733.38	746.37	12.99	1.8%
Residential Transitional Demand Mt Isa (MRTDEM)	4.24	4,878	688.93	687.97	-0.96	-0.1%
Residential ToU Energy Mt Isa (MRTOUE)	4.24	4,878	687.69	698.08	10.39	1.5%
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.						
Small Business (<100MWh pa) - Mt Isa						
Small Business IBT Mt Isa (MBIB)	6.32	7,535	932.68	947.69	15.02	1.6%
Small Business Demand Mt Isa (MBDEM)	6.32	7,535	1,039.61	1,055.56	15.95	1.5%
Small Business Transitional Demand Mt Isa (MBTDEM)	6.32	7,535	906.94	912.47	5.53	0.6%
Small Business ToU Energy Mt Isa (MBTOUE)	6.32	7,535	904.19	908.54	4.36	0.5%
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.						
Large Business (>100MWh pa) - Mt Isa						
Demand Small Mt Isa (MDS)	48.30	128,152	13,479.33	13,521.43	42.11	0.3%
Demand Medium Mt Isa (MDM)	176.42	653,439	42,818.50	43,287.13	468.62	1.1%
Demand Large Mt Isa (MDL)	391.55	1,677,698	88,518.56	89,785.43	1,266.88	1.4%
Large Business Time-of-Use Demand Mt Isa (MLTOUD)	391.55	1,677,698	114,067.79	117,033.45	2,965.66	2.6%

With ICC and CAC tariffs being confidential, we are not able to include a customer specific impact analysis. However, general trends in ICC and CAC customer impacts between 2020-21 and 2021-22 are presented below.

Table 22: Average customer impacts for the ICC and CAC tariff classes

Tariff Class	Impact	DUOS annual impact (%)	Jurisdictional schemes annual impact (%)	DPPC annual impact (%)	NUOS annual impact (%)
ICC	Average Impact	-5.5%	-9.2%	7.6%	0.9%
CAC	Average Impact	1.6%	-11.5%	2.2%	1.6%

Notes:Impacts based on forecast quantities t applied to rates t-1 and t.

These DUOS and NUOS charges are developed using the AER approved prices for 2020-21 and the proposed 2021-22 prices (included in Attachment 1 of with this Pricing Proposal). The network prices used for the customer impact analysis exclude GST.

To eliminate the impact of fluctuation in demand and energy between years, the same usage and demand profiles were used to calculate customers' bills for both 2020-21 and 2021-22.

8.1.5 Tariff simplicity

The structures of our tariffs have been developed in consideration of the feedback received as a result of the ongoing engagement with our customers and stakeholders as part of the development of our TSS (NER Clause 6.18.5(f)). We consider that our tariffs strike the right balance between cost reflectivity and customers' ability to understand and respond to the pricing signals.

8.1.6 Compliance with the NER and regulatory instruments

Clause 6.18.5(j) of the NER requires tariffs to comply with the NER and all applicable regulatory instruments. We confirm that our 2021-22 network tariffs have been developed to be compliant with the NER and the AER's Distribution Determination. We have demonstrated this through our approved TSS, this Pricing Proposal and associated attachments. A summary of our compliance with these obligations is set out in Appendix B: Compliance Checklist.

8.2 Alternative Control Services

Ergon Energy's Alternative Control Services tariffs have been developed in accordance with the NER and our TSS. Details of our compliance with the pricing principles are provided in Section 6 of our TSS.

With respect to our Alternative Control Services, by their nature, most of these services are requested by customers, and can vary according to the specific characteristics or circumstances of the customer. This suggests that customers have the ability and incentive to respond to cost reflective tariffs for these services.

We also note that customers are able to limit price impacts by considering whether a different variant of the service may be preferable (e.g. customers may, in some circumstances, minimise the cost incurred for some services by choosing to have the service delivered during business hours rather than after hours). This too is consistent with economic efficiency principles.

As noted in our TSS the price cap control mechanism limits customer impacts by constraining annual price increases to a certain level. Furthermore, we expect that the AER's Distribution Determination takes customer impacts into account when establishing structures and prices consistent with the efficient operation and use of services for the long-term interests of consumers.

9. Consistency with the TSS

This section provides our responses to the additional requirements set out in the AER's final determination on our 2020-25 TSS.

9.1 Consistency with price constraints

Our TSS includes prices control constraints for our SAC tariffs designed to limit customer impact while progressing tariff reform. In establishing the 2021-22 tariffs, we have taken these into account to achieve sustainable pricing outcomes.

Table 23 demonstrates our application of the rate setting framework set out in our TSS.

While we have not been able to achieve some of the aspirational targets for our SAC tariffs as a result of the forecast decline in energy consumption and customer numbers from the numbers used in our 2020-21 Pricing Proposal, results in the table below show that we have applied the approach in the TSS to the extent possible. Specifically, we are targeting a larger increase in revenue from legacy tariffs, while minimising changes in rates for our cost reflective tariffs, in order to maintain the tariff relativities outlined in our TSS.

Further, for our legacy residential and small business IBT tariffs, we are proposing changes to the rates these are presented in the table below (i.e. maintaining inclining block 3 energy consumption (volume) rates unchanged from the prior year and further increasing block 2 rates). We consider this an important to signal to customers and stakeholders to enable all parties to prepare for simplification of the IBT tariff structures post 2025.

Table 23: Consistency with the TSS annual price constraints

2020-21 TAR	2021-22 TAR	Annual charge in TAR	CI Overriding Ceiling
1,177,038,330	1,154,190,142	-1.94%	0.56%

SAC Large	Target level of revenue relative to change in TAR	Targeted Change	2020-21 adjusted revenue	2021-22 target revenue	Change in revenue
Demand Small	same	-1.94%	$115,017,433	$116,264,892	1.08%
Demand Medium	same	-1.94%	$107,843,612	$109,913,688	1.92%
Demand Large	same	-1.94%	$44,791,311	$45,532,147	1.65%
Demand TOU	same	-1.94%	$10,292,387	$10,545,832	2.46%
Large Residential Energy	same	-1.94%	$0	$0	0.00%
Large Business Energy	same	-1.94%	$4,788,069	$4,842,995	1.15%
Large Business Primary Load Control	same	-1.94%	$1,382,666	$1,412,901	2.19%

SAC Small	Target level of revenue relative to change in TAR	Targeted Change	2020-21 adjusted revenue	2021-22 target revenue	Change in revenue
Residential IBT	1% higher	-0.94%	$388,398,580	$398,367,939	2.57%
Small Business IBT	1% higher	-0.94%	$60,197,564	$61,686,881	2.47%
WIFT	1% higher	-0.94%	$95,127,869	$96,996,651	1.96%
Residential ToU Energy	1% higher	-0.94%	$292,779	$300,366	2.59%
Small Business ToU Energy	1% higher	-0.94%	$1,165,625	$1,195,920	2.60%
Residential Transitional Demand	same	-1.94%	$76,409,787	$78,070,266	2.17%
Small Business Transitional Demand	same	-1.94%	$25,112,782	$25,645,345	2.12%
Residential Demand	1% lower	-2.94%	$369,639	$374,344	1.27%
Small Business Demand	1% lower	-2.94%	$159,041	$161,408	1.49%

SAC Small - IBT	Target change in rates	Targeted Change	2020-21 rate	2021-22 proposed rate	Change in rate
Residential					
Fixed charge	Up to 5%	5.00%	1.100	1.105	0.45%
Block 1 charge	Increase by CPI	0.861%	0.02194	0.02213	0.86%
Block 2 charge	Balance as per revenue target		0.04402	0.04993	13.42%
Block 3 charge	Maintain 2020-21 level		0.08616	0.08616	0.00%
Business					
Fixed charge	Up to 5%	5.00%	1.100	1.105	0.45%
Block 1 charge	Increase by CPI	0.861%	0.02550	0.02572	0.86%
Block 2 charge	Balance as per revenue target		0.06572	0.07487	13.93%
Block 3 charge	Maintain 2020-21 level		0.11366	0.11366	0.00%

SAC Large	Target proportion relative to Demand charge	Permissible portion	2020-21 rate	2021-22 proposed rate
East				
Demand TOU - Demand charge			11.865	12.103
Demand TOU - Excess demand charge	Not exceed 30% of the applicable LRMC		2.373	2.421
Excess demand charge proportion of demand charge		30.00%	20.00%	20.00%
West				
Demand TOU - Demand charge			34.100	34.811
Demand TOU - Excess demand charge	Not exceed 30% of the applicable LRMC		6.820	6.962
Excess demand charge proportion of demand charge		30.00%	20.00%	20.00%
Mt Isa				
Demand TOU - Demand charge			11.677	11.912
Demand TOU - Excess demand charge	Not exceed 30% of the applicable LRMC		2.335	2.382
Excess demand charge proportion of demand charge		30.00%	20.00%	20.00%

9.2 New SAC Large basic meter tariffs

The AER's final determination on our 2020-25 TSS requires that Ergon Energy introduce new tariffs for residential and business customers with basic metering and consumption greater than 100MWh per year. These new tariffs are required to be introduced on 1 July 2021.

Proposed tariffs and tariff structures

From 1 July 2021, we propose to introduce two new SAC Large tariffs for basic meter customers, a residential version and a business version. Both tariffs have the same structure and proposed charges. The charges based on these tariffs use actual billable quantities, as opposed to the current practice of using inferred demand quantities.

The proposed tariffs and the associated tariff structures are described in Table 24.

Table 24: New SAC Large basic meter tariffs

Tariff	Tariff code	Tariff structure
Large Residential Energy	REST	• Inclining Block Tariff (IBT) with a fixed ($/day) charge and two energy consumption blocks, each with a different volumetric rate applicable ($/kWh) • Fixed charge has been set at the same rate as SAC Large, Demand Small tariff • IBT energy consumption blocks: Volume Block 1 – up to 97,000kWh per year Volume Block 2 – equal to or greater than 97,000kWh per year
Large Business Energy	BEST	• Inclining Block Tariff (IBT) with a fixed ($/day) charge and two energy consumption blocks, each with a different volumetric rate applicable ($/kWh) • Fixed charge has been set at the same rate as SAC Large, Demand Small tariff • IBT energy consumption blocks: Volume Block 1 – up to 97,000kWh per year Volume Block 2 – equal to or greater than 97,000kWh per year

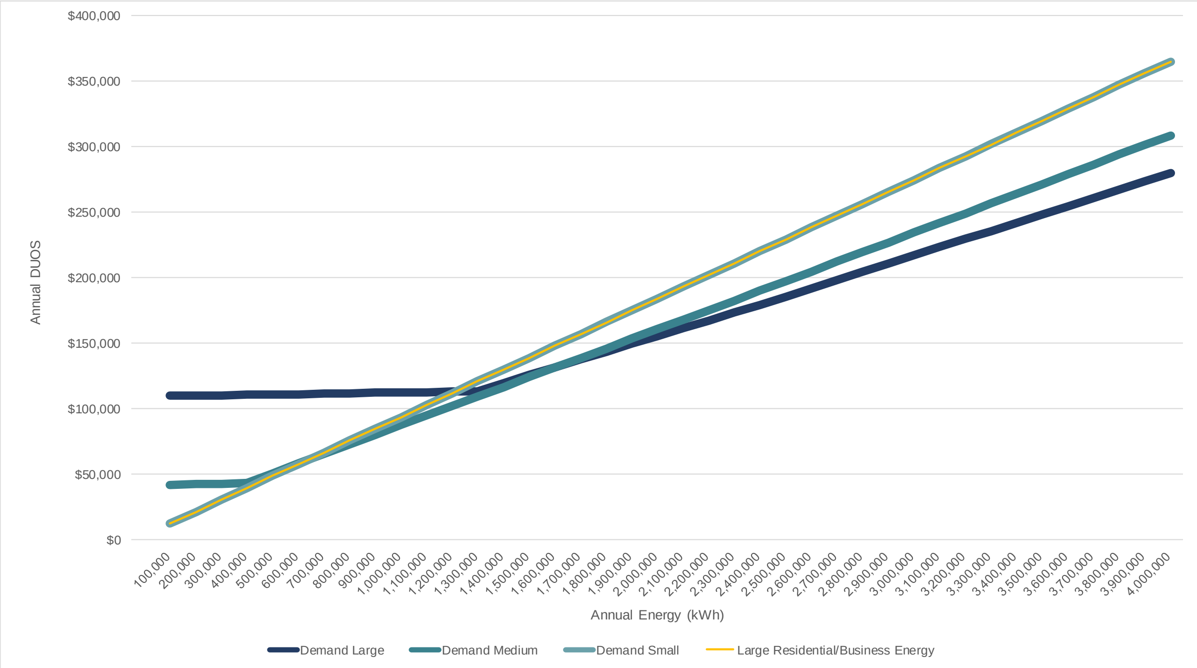
Customer impact analysis

Ergon Energy has approximately 300 customers with basic meters and consumption greater than 100MWh per year. These customers are currently assigned to SAC Large demand tariffs and billed using inferred demand quantities. The majority of these customers (over 90%) are currently on the Demand Small tariff.

To mitigate customer impacts, we propose to align network charges customers will face on the new basic meter tariffs with the existing Demand Small tariff. For the proposed new tariffs, the higher block volume charge is triggered once the customer exceeds the consumption threshold (97,000kWh per year). The consumption threshold is set at the level which has the same bill impact as the threshold for the application of the demand charges on the existing Demand Small tariff.

The chart in Figure 4 displays annual energy consumption data and DUOS charges for existing demand tariffs compared to the proposed new tariffs. With the exception of a limited number of customers on the Demand Large tariff consuming up to 1,200MWh per year or on Demand Medium consuming up to 400MWh per year, the chart shows that the majority of customers charged on inferred demand will see no impact from what they are currently charged.

Figure 4: Customer impact - 2021-22 Annual DUOS charges comparison - Demand Large, Demand Medium, Demand Small tariffs compared to proposed Large Residential and Business Energy tariff *(East pricing zone)*



Given the minimal customer impact, we propose to reassign all SAC Large customers with basic meters and consumptions exceeding 100MWh per annum to the new SAC Large basic meter tariffs upon their first meter read after 1 July 2021.

9.3 ICC price setting methodology

The AER's final determination on the 2020-25 TSS requires Ergon Energy to include in the pricing proposals for the 2021–22 regulatory year (and subsequent regulatory years) a detailed description of the approach to setting the ICC tariffs.

In contrast to our published network tariffs, ICC network tariffs are designed to be highly reflective of the costs of providing standard control services to an individual connection point. As a consequence, customers on ICC network tariffs will only pay less than under the equivalent CAC published tariffs if justified from a network cost to serve perspective. The only exception to this principle is the non-standard ICC tariffs that we are required under the final TSS to introduce on 1 July 2021. These tariffs are only available to certain CAC customers that are adversely impacted by the removal of retail obsolete and transitional tariffs. It is important to note that these tariffs are designed to provide these customers with a transitional path to cost reflectivity. At the end of this transition, customers on non-standard ICC tariffs will be paying the full network cost to serve.

9.3.1 Standard ICC tariff setting methodology

Ergon Energy's methodology for setting the price level of the ICC tariffs is designed to price the provision of electricity services in the most equitable and efficient manner possible. The equity outcomes under this methodology are achieved by allocating residual costs to site-specific connections in a manner that reflects their utilisation of the assets involved in the provision of network services. Favourable customer outcomes are also realised by transitioning the level of ICC tariffs where it is necessary to do so for customer impact considerations.[13] The superior economic efficiency outcomes associated with the ICC tariffs are achieved mainly by these customers receiving the pass through of Powerlink's transmission charges. This creates an important economic incentive for new ICC customers to locate in areas of the network that have a low cost to serve from a transmission perspective. In contrast to the published tariffs, the ICC tariffs are also capable of signalling economic costs in a manner that more accurately reflecting localised economic conditions.[14] The extent to which it is appropriate to signal economic costs to this degree is dependent upon a range of considerations, such as the nature of these economic conditions, the responsiveness of customers to price signals, the impact on customers as well as the transaction costs associated with developing more refined price signals.

A detailed description of each component of the ICC price-setting methodology is provided below.

DUOS price setting methodology

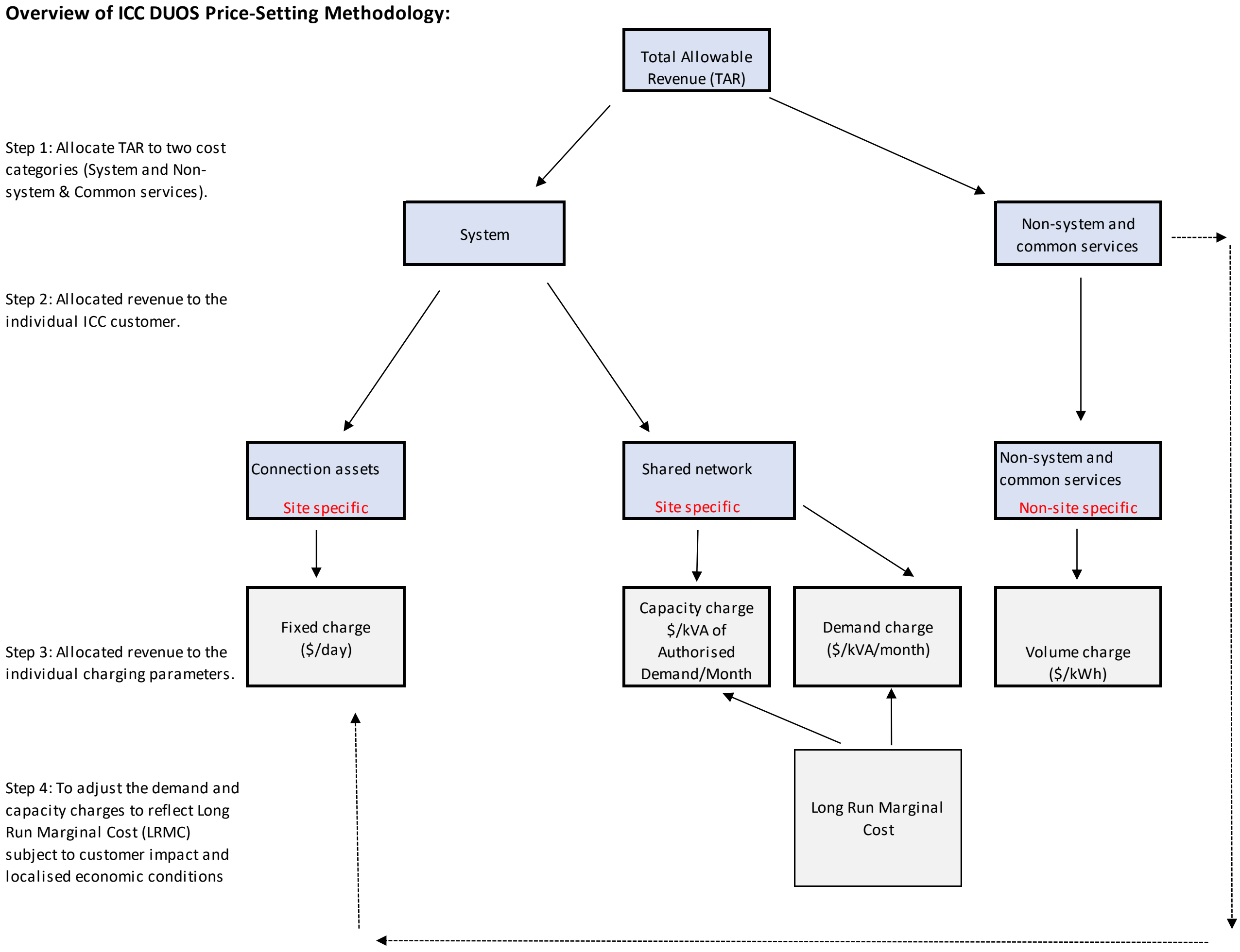
Ergon Energy's methodology for setting the DUOS prices for ICC customers is comprised of two broad stages:

The first step relates to the calculation of the distribution cost to serve for each ICC customer. This calculation involves a number of steps. The first step is to allocate the TAR for standard control distribution services into system and non-system components.[15] The second step is to allocate these costs into site-specific cost elements (i.e. connection and shared) and non-site specific cost elements (i.e. common and non-system). The third step is to allocate distribution cost to serve for an ICC customer into each of the individual charging parameters. The fourth step in this methodology is to adjust the tariff calculated under the previous step to determine the extent that is appropriate to signal LRMC cost through the demand charge. This evaluation is based on a range of considerations, such as customer impact consequence, the extent that customers are expected to respond to marginal price signals given the nature of their usage and the expected benefits from doing so given the nature of localised network conditions.

An overview of our methodology for allocation of residual DUOS costs and the signalling of LRMC is provided in Figure 5: DUOS cost allocation for ICCs.

[13] Refer to Clause 6.18.5(h) of the NER.
[14] Refer to Clause 6.18.5(f) of the NER.
[15] System costs are the directly attributable costs associated with the provision of network connection and distribution services. Non-system costs include items such as corporate support that are not directly attributable to the operation and maintenance of the network, but which are associated with network service delivery.

Figure 5: DUOS cost allocation for ICCs



DPPC price setting methodology

DPPC charges for ICC customers are site specific and based on the charges which Powerlink charges Ergon Energy at the Bulk Supply Point at which the customer is connected.

Table 25: DPPC charging parameters

Powerlink charges	Methodology to convert Powerlink's charge to DPPC charge	Corresponding DPPC charging parameter	Application
Entry/Exit connection charge ($'000/month)	Entry/Exit connection charge is apportioned to ICC customers using customers individual monthly peak demand (kW) and the total demand supplied through that Bulk Supply Point	Fixed charge ($/day)	Site and customer specific price
Locational charge ($/kW/month)	This charge is a direct pass-through	Locational charge ($/kW/month)	DPPC charge applied to individual ICC forecast monthly peak demand kW
General energy charge (c/kWh)	This charge is a direct pass-through	General services charge ($/kWh)	DPPC charge applied to individual ICC forecast annual energy (kWh)
Common service energy charge (c/kWh)	This charge is a direct pass-through	Common services charge ($/kWh)	DPPC charge applied to individual ICC forecast annual energy(kWh)

<u>Allocation of forecast TUOS revenue to ICC customers</u>

TUOS revenue is allocated to individual ICCs based on the charges set by Powerlink Qld (PLQ) at the Bulk Supply Point which they are connected. These charges are summarised below:

- Entry/Exit connection costs
  - These are site specific charges unique to each Bulk Supply Point.
  - To allocate TUOS revenue for Entry/Exit connection costs to an ICC, the Entry/Exit connection revenue is apportioned using individual monthly peak demand kW and the total demand supplied through that Bulk Supply Point.
- Locational demand charge
  - These are Shared Network rates published by PLQ.
  - PLQ charge applied to individual ICCs' forecast monthly peak demand kW.
  - This charge is a direct pass-through.
- General energy charge
  - These are Shared Network rates published by PLQ.
  - PLQ charge applied to individual ICCs' forecast annual energy.
  - This charge is a direct pass-through.
- Common service energy charge
  - These are Shared Network rates published by PLQ.
  - PLQ charge applied to individual ICCs' forecast annual energy
  - This charge is a direct pass-through.

Jurisdictional Scheme price setting methodology

Jurisdictional Scheme (JS) charges for ICC customers are not site specific, that is the same Fixed ($/day) and Volume ($/kWh) charge applies to all ICC customers.
Step 1: JS revenue allocation

To allocate an ICCs JS revenue the default is the same for all network tariff classes being proportion of the total JS revenue using customer numbers and energy.

Step 2: The JS allocation is then converted to rates

These rates a not site specific, the same JS Fixed and Volume charge applies to all ICCs. The rates are struck using the sum of individual ICCs numbers and forecast annual energy. The split of allocation between Fixed and Volume charges is done by tariff group.

9.3.2 Non-standard ICC tariff setting methodology

To comply with the AER approved final TSS, Ergon Energy will introduce non-standard (transitional) ICC tariffs on an opt-in basis for eligible CAC customers from 1 July 2021. This process is only available to existing CAC customers on an obsolete retail transitional tariff set out by the Queensland Commission Authority (QCA), in the period 1 July 2017 to 30 June 2020. Any such re-assignment application must be made between 1 July 2020 and the date by which the transitional tariff(s) will be retired (currently scheduled for 30 June 2021). To be considered for a non-standard ICC tariff, the applicant must comply with the steps set out in the TSS (Appendix A).

We have developed a process for customers seeking to apply for a re-assignment to the non-standard ICC tariffs. A confidential copy of the procedure, including customer applications received to date is provided in Attachment 4.

The proposed approach to setting the non-standard (transitional) ICC tariffs involves the following steps:

Step 1: To calculate the network use of system prices for this individual customer's coupling point under the standard ICC price-setting methodology.

Step 2: To calculate the annual LRMC-based DUOS revenue on the basis of the expected peak demand requirements at the individual customer's coupling point. Ergon Energy proposes to base this calculation on the following:

- Estimate the LRMC of supplying standard control electricity distribution network services to the individual customer's coupling point. To satisfy this requirement, Ergon Energy proposes to apply the published LRMC estimates at the voltage level of individual customer's coupling point.
- Estimate the expected peak demand requirements at the individual customer's coupling point.

Step 3: To adjust the network tariff derived in Step 1 for the purpose of transitioning the LRMC price signal by discounting the annual LRMC-based DUOS revenue attributed to the individual customer's coupling point to the extent necessary to mitigate the impact of the introduction of cost reflective price signals. The adjustment will be made to the demand and/or capacity charging parameters.

Step 4: To develop a medium term price path with the objective of transitioning the LRMC DUOS revenue for the individual customer to full cost reflectivity over a maximum of a 10-year timeframe in light of the customer impact consideration and the nature of economic conditions (eg: extent of network congestion, etc) in the area of the network that the customer's individual coupling point is located.

9.4 Outcomes from the legacy tariff review

The AER's final determination on our 2020-2025 TSS required Ergon Energy to undertake a review of network pricing and billing arrangements in order to identify any potential legacy system and tariff arrangements which pre-date the TSS requirement in the NER.

We have concluded this review and have found that there are no legacy tariff arrangements of this nature in Ergon Energy (i.e. Ergon Energy had been fully compliant the 2017-22 TSS). A report on the outcomes of the review was provided to the AER in February 2021 for their consideration.

9.5 Trial of capacity-based tariffs

We are continuing to progress development of capacity tariffs in line with our belief that capacity-based tariff structures are the best tariff option to apply in response to the emerging challenges facing the distribution networks - emergent EV charging demand, two sided markets, battery presentation to the network and declining minimum demand.

In line with the pathway indicated in the AER's 2020-25 TSS Final Decision, we are undertaking capacity tariff research and developing responses to the 2020-25 TSS stakeholder feedback with a view to undertaking additional stakeholder engagement as we advance capacity tariff development.

Appendix A: Terms and conditions for load control tariffs

	SAC Small		SAC Large	
	Primary Load Control Tariff – Business	Secondary Load Control Tariffs – Business or Residential	Primary Load Control Tariff – Business	Secondary Load Control Tariff – Business
Availability of Electricity Supply	• Electricity supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of the Distribution Network Provider (DNSP). • In emergency conditions as an alternative to removing all supply, we reserve the right to control the load for periods in excess of the times stated in the tariff conditions.	• Electricity supply will be available for either a minimum period of 18 hours per day (Volume Controlled) or a minimum of 8 hours per day, (Volume Night Controlled - usually between the hours of 10 pm and 7am) depending on which load control tariff option is chosen. Times when supply is available is subject to variation at the absolute discretion of the Distribution Network Provider (DNSP). • In emergency conditions as an alternative to removing all supply, we reserve the right to control the load for periods in excess of the times stated in the tariff conditions.	• Electricity supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of the Distribution Network Provider (DNSP). • In emergency conditions as an alternative to removing all supply, we reserve the right to control the load for periods in excess of the times stated in the tariff conditions.	• Electricity supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of the Distribution Network Provider (DNSP). • In emergency conditions as an alternative to removing all supply, we reserve the right to control the load for periods in excess of the times stated in the tariff conditions.
Eligibility Criteria for Load Control Tariff access	• Any business customer, regardless of their metering type, can access the tariff. • Standard connection times apply in accordance with the Guaranteed Service Levels or as agreed. • The customer will notify us of any change greater or less than 30kW to the existing and approved load connected to the tariff.	• Any customer, regardless of their metering type, can access the tariff. • Standard connection times apply in accordance with the Guaranteed Service Levels or as agreed. • The customer will notify us of any change greater or less than 30kW to the existing and approved load connected to the tariff.	• Any customer, regardless of their metering type, can access the tariff. • Customer MUST be in an area that the relevant DNSP is able to actively remove / reinstate supply through the DNSPs standard load control signalling technology. • Eligibility for this tariff may require a network assessment. If a network assessment is required to identify any adverse impact	• Any customer, regardless of their metering type, can access the tariff. • Customers eligible for the Large Residential Energy (REST) tariff may access this tariff. • Customer MUST be in an area that relevant DNSP is able to remove / reinstate supply through the DNSPs standard load control signalling technology.

			on the network, it may delay the approval process. The impact assessment may include but is not limited to the nature / size of the load or in consideration of existing load control capacity in the same network area. • Standard connection times apply in accordance with the Guaranteed Service Levels or as agreed. • The customer will notify us of any change greater or less than 30kW to the existing approved load connected to the tariff.	• Eligibility for this tariff may require a network assessment. If a network assessment is required by the DNSP to identify any adverse impact on the network, it may delay the approval process. The impact assessment may include but is not limited to the nature / size of the load or in consideration of existing load control capacity in the same network area. • Standard connection times apply in accordance with the Guaranteed Service Levels or as agreed. • The customer will notify us of any change greater or less than 30kW to the existing and approved load connected to the tariff.
Technical and Wiring Requirements	• The premises must have been wired in accordance with the requirements of the Queensland Electricity Connection Manual (QECM) at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. • Hard wired and non-hard wired permitted • The equipment to be connected to load control tariff must be suitable to be controlled through interface with the standard network device (load control relay), supplied by us. Where a contactor is required, it shall be supplied by the customer (as per QECM)	• The premises must have been wired in accordance with the requirements of the Queensland Electricity Connection Manual (QECM) at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. • Hard wired only, except for the exemptions outlined below • The equipment to be connected to load control tariff must be suitable to be controlled through interface with the standard network device (load control relay), supplied by us. Where a contactor is required, it shall	• The premises must have been wired in accordance with the requirements of the Queensland Electricity Connection Manual (QECM) at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. • Hard wired and non-hard wired permitted • The equipment to be connected to load control tariff must be suitable to be controlled through interface with the standard network device (load control relay), supplied by us. Where a contactor is required, it shall	• The premises must have been wired in accordance with the requirements of the Queensland Electricity Connection Manual (QECM) at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. • Hard wired only except for the exemptions outlined below • The equipment to be connected to load control tariff must be suitable to be controlled through interface with the standard network device (load control relay), supplied by Ergon Energy. Where a

	• Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the QECM requirements, is the responsibility of the customer eg contactors and meter wiring.	be supplied by the customer. (as per QECM) • This tariff will be removed from any premises where the customer has the ability to supply the appliance or equipment via another tariff (eg changeover switch to a primary tariff). The primary tariff rate will apply until the defect is rectified. • Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the requirements of the QECM, is the responsibility of the customer eg contactors and meter wiring.	be supplied by the customer. (as per QECM) • Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per requirements of the QECM, is the responsibility of the customer eg contactors and meter wiring.	contactor is required, it shall be supplied by the customer. (as per QECM) • This tariff will be removed from any premises where the customer has the ability to supply the appliance or equipment via another tariff (eg changeover switch to a primary tariff). The primary tariff rate will apply until the defect is rectified. • Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the requirements of the QECM, is the responsibility of the customer eg contactors and meter wiring.
Eligible Equipment to be connected to load control tariffs	• Customers can connect general light and power, including the following equipment or appliances to this tariff: (i) Electric storage water heaters with thermostatically controlled or continuously operating heating units. (ii) Boost elements of solar-heated water heaters. (iii) Electric Vehicle Supply Equipment (EV Chargers). (iv) Pool filtration systems. (v) Heat pump water heaters. (vi) Other appliances (e.g. washing machines and dishwashers) (vii) Pumping and irrigation equipment (viii) Battery Energy Storage Systems (BESS) (ix) Solar PV	• Electricity supply must be permanently connected to the items on the approved list, except for pool filtration systems and electric vehicle supply equipment / EV chargers which can be supplied through a dedicated socket-outlet only in domestic premises. In small businesses only pool filtration systems can be supplied through a dedicated socket. (i) Electric storage water heaters with thermostatically controlled or continuously operating heating units. (ii) Boost elements of solar-heated water heaters.	• Customers can connect all light and power, including the following equipment or appliances to this tariff: (i) Electric storage water heaters with thermostatically controlled or continuously operating heating units. (ii) Boost elements of solar-heated water heaters. (iii) Electric Vehicle Supply Equipment (EV Chargers). (iv) Pool filtration systems. (v) Heat pump water heaters. (vi) Other appliances (e.g. washing machines and dishwashers). (vii) Pumping and irrigation equipment.	• Electricity supply must be permanently connected to the items on the approved list, except for pool filtration systems which may be supplied through a dedicated socket outlet: (i) Electric storage water heaters with thermostatically controlled or continuously operating heating units. (ii) Boost elements of solar-heated water heaters. (iii) Electric Vehicle Supply Equipment (EV Chargers). (iv) Pool filtration systems. (v) Heat pump water heaters.

	(x) Other equipment as approved by us.	(iii) Electric Vehicle Supply Equipment (EV Chargers). (iv) Pool filtration systems. (v) Heat pump water heaters. (vi) Other appliances (e.g. washing machines and dishwashers). (vii) Pumping and irrigation equipment. (viii) Battery Energy Storage Systems (BESS) (ix) Solar PV (x) Other equipment as approved by us (non-domestic premises only)	(viii) Battery Energy Storage Systems (BESS). (ix) Solar PV. (x) Other equipment as approved by us	(vi) Other appliances (e.g. washing machines and dishwashers). (vii) Pumping and irrigation equipment. (viii) Battery Energy Storage Systems (BESS). (ix) Solar PV (x) Other equipment as approved by us

*Eligibility for the SAC Large load control tariff (primary and secondary) in relation to being located in an area which has the required standard load control signalling technology can be checked through a NMI search tool at www.ergon.com.au/loadcontroltariffs

Appendix B: Compliance Checklist

Table 26: Compliance with the National Electricity Rules

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
6.18.2	**Pricing Proposals**	
6.18.2(a)	**A Distribution Network Service Provider must:**	
6.18.2(a)(1)	Submit to the AER, as soon as practicable, and in any case within 15 business days, after publication of the distribution determination, a pricing proposal (the initial pricing proposal) for the first regulatory year of the regulatory control period.	Not applicable in 2021-22
6.18.2(a)(2)	Submit to the AER, at least 3 months before the commencement of the second and each subsequent regulatory year of the regulatory control period, a further pricing proposal (an annual pricing proposal) for the relevant regulatory year.	Our Pricing Proposal was submitted to the AER by the appropriate date (30 March)
6.18.2(b)	**A Pricing Proposal must:**	
6.18.2(b)(2)	Set out for the proposed tariffs for each tariff class that is specified in the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period.	Section 2.1 (Standard Control Services) Section 4.1 and 4.2(Alternative Control Services) The 2021-22 tariffs and tariff structures are consistent with our TSS
6.18.2(b)(3)	Set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.	Section 2.2 (Standard Control Services) Section 4.2 (Alternative Control Services)
6.18.2(b)(4)	Set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year.	Section 3.2.3
6.18.2(b)(5)	Set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.	Section 7.1 (Standard Control Services) Section 7.2 (Alternative Control Services)
6.18.2(b)(6)	Set out how designated pricing proposal charges are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year.	Section 3.3
6.18.2(b)(6A)	Set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts.	Section 3.4

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
6.18.2(b)(6B)	Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	There have been no changes to the jurisdictional schemes since their last jurisdictional scheme approval dates.
6.18.2(b)(7)	Demonstrate compliance with the NER and any applicable distribution determination, including the Distribution Network Service Provider's Tariff Structure Statement for the relevant regulatory control period.	This table and this Pricing Proposal (including attachments and appendixes to this Pricing Proposal) demonstrates how Ergon Energy complies with the NER, the Distribution Determination and its TSS.
6.18.2(b)(7A)	Demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the indicative pricing schedule, or explain any material differences between them.	Section 5 Attachment 3 sets out the material differences between the 2021-22 indicative pricing levels (as set out in our 2020-21 Pricing Proposal) and the proposed 2021-22 tariffs included in Attachment 1
6.18.2(b)(8)	Describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable distribution determination.	Section 6 How these changes comply with the NER and any applicable Distribution Determination is set out in this table
6.18.2(c)	The AER must on receipt of a pricing proposal from a Distribution Network Service Provider publish the proposal.	Noted
6.18.2(d)	At the same time as Distribution Network Service Provider submits its pricing proposal under paragraph (a), the Distribution Network Service Provider must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with Distribution Network Service Provider's tariff structure statement for that regulatory control period and updated so as to take into account that pricing proposal.	The indicative prices for each of the remaining regulatory years of the regulatory control period are provided in Attachment 2 of this Pricing Proposal
6.18.2(e)	Where Distribution Network Service Provider submits an annual pricing proposal, the revised indicative pricing schedule referred to in paragraph (d) must also set out, for each relevant tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.	Attachment 2 of this Pricing Proposal
6.18.5	**Pricing principles**	
6.18.5(e)(1) and (2)	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 8.1.1 (Standard Control Services) Section 8.2 (Alternative Control Services) Section 3.2 and 6 of the TSS

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
6.18.5(f)(1), (2) and (3)	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 location in the distribution network.	Section 8.1.2 (Standard Control Services) Section 8.2 (Alternative Control Services) Section 3.3 and 6 of the TSS
6.18.5(g)(1), (2) and (3)	The revenue expected to be recovered from each tariff must: (1) reflect Distribution Network Service Provider's total efficient cost 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 Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for 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 8.1.3 (Standard Control Services) Section 8.2 (Alternative Control Services) Further information on how we meet this pricing principle is also available in our TSS
6.18.5(h)(1), (2) and (3)	Distribution Network Service Provider must consider the impact on 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 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 8.1.4 and Section 6.2 (Standard Control Services) Section 8.2 and Section 6.3 (Alternative Control Services)
6.18.5(i)(1) and (2)	The structure of each tariff must be reasonably capable of being understood by 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 8.1.5 (Standard Control Services) Section 8.2 (Alternative Control Services) Further information on how we meet this pricing principle is also available in our TSS
6.18.5(j)	A tariff must comply with the NER and all applicable regulatory instruments.	Section 1.3 and Section 8.1.6 (Standard Control Services) Section 8.2 (Alternative Control Services)

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
6.18.7	**Recovery of designated pricing proposal charges**	
6.18.7(a)	A pricing proposal must provide for tariffs designated to pass on to retail customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider.	Section 3.3
6.18.7A	**Recovery of jurisdictional scheme amounts**	
6.18.7A(a)	A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes.	Section 3.4

Appendix C: Glossary

Table 27: Acronyms, abbreviations and definitions

Term	Abbreviation / Acronym	Definition
Alternative Control Service		Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local DNSP.
Anytime Maximum Demand	AMD	The demand for some network tariffs is calculated using 'any-time' demand. For these tariffs, the customers chargeable maximum demand is the highest 30 minute demand period, regardless of when that occurs during the month.
Australian Energy Regulator	AER	The economic regulator of the NEM established under section 44AE of the *Competition and Consumer Act 2010* (Commonwealth).
Authorised demand		The maximum demand permitted to be imported or exported to the network by a network user, based on the nature of their connection.
Business hours	BH	8 am to 5 pm, Monday to Friday.
Basic meter		Basic accumulation meters are defined as a meter that is only capable to recording the customers' energy consumption during the billing period.
Capacity charge		A type of charge (charging parameter) included in network tariff structures. The capacity charge seeks to reflect the costs associated with providing network capacity required by a customer on a long term basis. It is levied on the basis of either contracted demand or forecasted capacity using prior year information.
Capital expenditure	Capex	Expenditure typically resulting in an asset (or the amount Ergon Energy has spent on assets).
Charging parameter		The charges comprising a tariff. Parameters include demand, capacity, fixed and volume (flat or time-of-use) charges.
Common service		A service that ensures the integrity of a distribution system, benefits all distribution customers and cannot reasonably be allocated on a locational basis.
Connection asset (Contributed or non-contributed)		Related to building connection assets at a customer's premises as well as the connection of these assets to the distribution network. Connection assets can be contributed (customer funded, then gifted to Ergon Energy) or non-contributed (Ergon Energy funded).
Connection point		The agreed point of supply established between a Network Service Provider and another Registered Participant, Non-Registered Customer or franchise customer. The meter is installed as close as possible to this location.
Customer		Refer to chapter 10 of the NER.
Demand		The amount of electricity energy being consumed at a given time measured in either kilowatts (kW) or kilovolt amperes (kVA). The ratio between the two is the power factor.
Demand charge		A type of charge (charging parameter) included in network tariff structures. This charge accounts for the actual demand a customer places on the electricity network. Different parameters apply to this charged depending on the different tariffs.
Demand tariff		The tariff has been structured to include a demand component so the customer's actual demand is reflected in the price they pay for their electricity.
Designated Pricing Proposal Charge	DPPC	Refers to the charges incurred for use of the transmission network; previously referred to as Transmission Use of System (TUOS).

Term	Abbreviation / Acronym	Definition
Distribution Use of System	DUOS	This refers to the network charges which recover the costs of providing Standard Control Services.
Embedded Generator	EG	In line with the ENA classification, EGs are generally those generators with an installed capacity as follows: Medium: 1-5 MVA (LV or HV) or < 1 MVA (HV) Large: > 5 MVA EGs are separated into two categories: • EGs that are connected to the distribution system and only generate into the distribution system • EGs that are connected to the distribution system, generate and take load from the system
Energy (or usage)		The amount of electricity consumed by a customer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Feed-in Tariff	FiT	The rate that is to be paid for the excess energy generated by customers and fed back into the electricity grid under the Queensland Solar Bonus Scheme. The FiT rate is determined by the Queensland Government and is paid by the purchaser of the excess energy.
Final Determination		A regulatory determination decision document published by the AER. In this proposal, reference to the Final Determination refers to the 2020-2025 AER Final Determination.
Fixed (or access) charge		A type of charge (charging parameter) included in network tariff structures which is levied on a fixed dollar amount per day.
High Voltage	HV	Refers to the network at 11 kV or above.
Large customer classification		As per tariff class assignment process for customers with consumption greater than 100 MWh per year.
Large customer connection	LCC	Large customer connections are those connections that fall within the tariff classes of Individually Calculated Customer (ICC) and Connection Asset Customer (CAC) including embedded generators.
Long Run Marginal Cost	LRMC	An estimate of the cost (long term variable investment) of augmenting the existing network to provide sufficient capacity for one additional customer to connect to the network or an additional MW of demand.
Low Voltage	LV	Refers to the sub-11 kV network
Maximum demand		The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Micro Generator		AS4777-compliant generators with an installation size of less than 10 kW (single phase) or 30 kW (three phase) connected to the LV network.
National Electricity Law	NEL	The legislation that establishes the role of the AER as the economic regulator of the NEM and the regulatory framework under which the AER operates.
National Electricity Market	NEM	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Electricity Rules	NER (the NER)	The legal provisions (enforced by the AER) that regulate the operation of the NEM and the national electricity systems, the activities of market participants and the provision of connection services to retail customers.

Term	Abbreviation / Acronym	Definition
National Metering Identifier	NMI	A unique number assigned to each metering installation.
Network capacity		The maximum demand (kW) that the distribution network can provide for at any one time.
Network Coupling Point	NCP	The point at which connection assets join a distribution network, used to identify the distribution service price payable by a customer.
Network Tariff Code	NTC	Ergon Energy’s nominated code that represents the network tariff being charged to customers for network services.
Network Use of System	NUOS	The tariff for use of the distribution and transmission networks. It is the sum of both Distribution Use of System (DUOS) and DPPC.
Non-demand tariff		The tariff is based around a fixed daily component and the actual usage (or energy), expressed in kWh, used by the customer.
Operating expenditure	Opex	Opex is the combined total of maintenance and operating costs. Maintenance Costs are those that are directly and specifically attributable to the repair and maintenance of network assets, while Operating Costs are those that relate to the day to day operations of Ergon Energy which are not maintenance costs.
Power factor		Power factor is the ratio of kW to kVA, and is a useful measure of the efficiency in the use of the network infrastructure. The closer the power factor is to one (1), the more efficiently the network assets are utilised. Power factor = kW / kVA
Pricing principles		The pricing principles are established in clause 6.18.5 of the NER and provide guidance to Ergon Energy for setting tariffs.
Public lights - Major		Lamps in common use for major road lighting including: • High Pressure Sodium above 100 watt • Metal Halide above 125 watt • Mercury Vapour above 125 watt, and • Light Emitting Diode 50 watt and above.
Public lights - Minor		All lamps in common use for minor road lighting, including: • High Pressure Sodium – up to and including 100 watt • Metal Halide – up to and including 125 watt • Mercury Vapour – up to and including 125 watt • Light Emitting Diode below 50 watt • Compact Fluorescent, Fluorescent and Incandescent – all wattages, and • Low Pressure Sodium – all wattages.
Queensland Government Solar Bonus Scheme	SBS FiT	A program that pays residential and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland electricity grid.
Regulatory Control Period		A standard Regulatory Control Period for DNSPs is a period of not less than 5 regulatory years. Ergon Energy’s current Regulatory Control Period is 2020-25, commencing 1 July 2020.
Regulatory depreciation		Also referred to as the return of capital – the sum of the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).
Regulatory year		A specific year within the regulatory control period.
Return on capital		The return necessary to achieve a fair and reasonable rate of return on the assets necessarily invested in the business.

Term	Abbreviation / Acronym	Definition
Service Target Performance Incentive Scheme	STPIS	A scheme developed and published by the AER in accordance with clause 6.6.2 of the NER, that provides incentives (that may include targets) for DNSPs (including Ergon Energy) to maintain and improve network performance.
Side constraint		A side constraint is an upper limit on price increases applied at the tariff class level for SCS and is calculated in accordance with clause 6.18.6 of the NER and the AER Determination Decision. The purpose of a side constraint is to mitigate the impact of prices on customers from one year to the next within a regulatory control period.
Site-specific charge		This charge is calculated for a site and is specific to the individual connection point.
Small customer classification		As per tariff class assignment process for customers with consumption less than 100 MWh per year.
Smart meter		Digital, interval and advanced Type 1-4 meters. Meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
Solar Photovoltaic	Solar PV	A system that uses sunlight to generate electricity for residential use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Control Service	SCS	Distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. This service classification includes network services (e.g. construction, maintenance and repair of the network), basic connection services and Type 7 metering services (i.e. unmetered connections such as traffic lights).
Tariff		The set of charges applied to a customer in the respective billing period. A tariff consists of one or more charging parameters that comprise the total tariff rate.
Tariff class		A class of customers for one or more *direct control services* who are subject to a particular tariff or particular tariffs (as per chapter 10 of the NER).
Tariff Structure Statement	TSS	Document prepared in accordance with Part I of chapter 6 of the NER, setting out Ergon Energy's network price structures and indicative tariffs that will apply over each year of the regulatory control period. Ergon Energy's approved 2020-25 TSS takes effect from 1 July 2020.
Threshold demand		The amount by which a SAC Large customer's metered monthly actual kW maximum demand is adjusted for the purposes of calculating the demand component of their network tariff. The actual demand charge for any time demand tariffs and the peak and off-peak demand charges for the Seasonal Time of Use Demand tariffs are applied to the kW amount by which the recorded monthly maximum demand exceeds the relevant threshold. This demand may occur at any time during the month (actual demand charge and off-peak demand charge) or during a set peak period (peak charge). Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.
Time-of-use	ToU	A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff may apply a different price during peak, shoulder and off-peak periods.
Total annual revenue	TAR	Refer to AER, Final Decision Ergon Energy determination 2020 to 2025, Attachment 13 – Control Mechanism, June 2020.
Transmission Use of System charge	TUOS	Superseded terminology for DPPC which are charges incurred for use of the transmission network.
Unmetered supply		A customer who takes supply where no meter is installed at the connection point.

Term	Abbreviation / Acronym	Definition
Usage or Volume charge		A type of charge (charging parameter) included in network tariff structures which is calculated using the customer's metered energy (kWh) consumption. It may be based on a flat rate, an inclining block or TOU charging structure (depending on the customer's applicable network tariff). This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer.
X Factor		Under the CPI – X form, prices or allowed revenues are adjusted annually for inflation (CPI) less an adjustment factor 'X'. The X Factor represents the change in real prices or revenues each year, so the DNSP can recover the costs that it expects to incur over the regulatory control period.

Table 28: Units of measurement used throughout this document

Base Unit	Unit name	Multiples used in this document
h	hour	GWh, kWh, MWh
V	volt	kV, kVA, MVA
VA	volt ampere	kVA, MVA
var	var	kvar
W	watt	W, kW, kWh, MW

Table 29: Multiples of prefixes (units) used throughout this document

Prefix symbol	Prefix name	Prefix multiples by unit	Prefixes used in this document
G	giga	10^9	GWh
M	mega	1 million or 10^6	MW, MWh, MVA
k	kilo	1 thousand or 10^3	kV, kVA, kvar, kW, kWh

Appendix D: Confidentiality template

Title, page and paragraph number of the document containing the confidential information	Description of the confidential information	Topic the confidential information relates to (e.g. capex, opex, the rate of return)	Provide a brief explanation of why the confidential information falls into the selected category	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit
Ergon Energy's Tariff Approval Model	Individually Calculated Customers (ICC) Site Specific tariffs.	2021-22 proposed tariffs for the ICC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Ergon Energy will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing Individual Calculated Customers' prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.
Ergon Energy's Tariff Approval Model	Connection Asset Customers (CAC) Site Specific Tariffs	2021-22 proposed tariffs for the CAC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Ergon Energy will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing CAC site specific prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.
Ergon Energy's Applications for Non-Standard ICC tariff	Customer information including proposed site specific pricing	Proposed tariffs for Non-standard ICC customers	Site specific prices are not published due to the confidentiality requirements of the customer. Ergon Energy will provide these site-specific tariffs directly to the customer and their retailer.	Personal information	There is little or no public benefit to disclosing non-standard ICC site specific prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.