Ergon Energy
Final Initial Pricing Proposal

Distribution services for 1 July 2020 to 30 June 2021

26 June 2020

Version	Date	Description
V1.0	26 May 2020	Indicative Initial Pricing Proposal submitted to the AER for review
V2.0	10 June 2020	Final Initial Pricing Proposal submitted to the AER for approval
V2.2	26 June 2020	Updated Final Initial Pricing Proposal submitted to the AER for approval

Contents

1. Introduction

1.1 Our business

On 30 June 2016, Ergon Energy Limited (Ergon Energy) became a subsidiary of Energy Queensland Limited which is the holding company for both Energex and Ergon Energy Corporation Limited (Ergon Energy). Ergon Energy is the Distribution Network Service Provider (DNSP) that builds, owns, operates and maintains the electricity distribution network in regional Queensland. We provide distribution services to around 730,000 customers. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of our network's power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

Our key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for our customers, manages risk and builds a sustainable future.

1.2 Purpose

This document is Ergon Energy's final Initial Pricing Proposal for 2020-21 (Pricing Proposal) the first regulatory year of the 2020-25 regulatory control period. In accordance with clause 6.18.2(a)(1) of the National Electricity Rules (the NER)[1], it is submitted for approval to the Australian Energy Regulator (AER) within 15 business days after publication of the distribution determination.

1.3 Background

On 30 April 2020, the AER was to publish its final decision on Ergon Energy's distribution determination and Tariff Structure Statement (TSS) for 2020-25

The publication of the AER's final decision was delayed until 5 June 2020. The AER has advised that Ergon Energy is required to submit an indicative 2020-21 Pricing Proposal by 26 May 2020 with a final proposal to be submitted by 10 June 2020. 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[2] and is also available on the AER's website[3].

This Pricing Proposal (and the attachments forming part of this Pricing Proposal) sets out our proposed tariffs and services for all Ergon Energy's Direct Control Services for the 2020-21 regulatory year.

1.3.1 Classification of distribution services

As a DNSP, 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

[1] The National Electricity Rules, Version 138.
[2] https://www.ergon.com.au/network/network-management/network-pricing/network-tariffs
[3] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/final-decision

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. These services may also have potential for provision on a competitive basis rather than by a single DNSP. 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 (examples include 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 supplied.
  - Public Lighting services – services relate to the provision, installation and maintenance of public lighting assets and emerging public lighting technology. We recover the costs of providing Public Lighting Services through a fixed daily public lighting charge billed to retailers. We may also charge a one-off exit fee (as a quoted service), when a customer requests the replacement of an existing public light before the end of its useful life e.g. customer requests relocations or road diversions.
  - 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).

1.4 Regulatory framework

1.4.1 Compliance with the NER

Ergon Energy's network tariffs have been developed in accordance with the NER. In accordance with clause 6.18.5(a) of the NER, our objective is to ensure that the tariffs charged for 2020-21 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 Appendix C: Compliance Checklist of this Pricing Proposal and our 2020-25 TSS.

1.4.2 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 – 2020-21 Network Tariff Tables and Attachment 2 – Indicative Pricing Schedule 2020-25. We confirm this Pricing Proposal complies with the AER's Final Decision.

1.4.3 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 and demonstrates compliance with the pricing principles set out in Chapter 6 of the NER. The TSS interfaces with Ergon Energy's pricing proposals, and each pricing proposal must be consistent with the approved TSS.

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. Differences in proposed 2020-21 rates from the indicative rates provided in our 2020-25 Revised TSS are explained in Section 7.

1.4.4 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 maximum price caps in Schedule 8, may be higher than those charged to customers.

1.5 Summary of changes

This Pricing Proposal is the first developed in accordance with our 2020-25 TSS and Distribution Determination. The key pricing reforms proposed for 2020-21 and approved by the AER are:

Standard Control Services

- Introduction of a suite of three new cost reflective tariffs for both residential and small business customers with digital metering – a Transitional Demand, Demand and ToU Energy tariff. Our tariff assignment process has been amended to reflect these tariffs. From 1 July 2020, the Transitional Demand tariff will be the default tariff for new customers and existing customers which initiate meter changes.
- Introduction of a new Small Business Wide Inclining Fixed Tariff (WIFT) for small business customers with basic meters and consumption above 20MWh.
- Introduction of a new tariff, Large Business ToU Demand, for large business customers with consumption greater than 100MWh per year.
- Introduction of three new opt-in load control tariffs for business customers, including:
    - a primary load control tariffs for small business customers with a basic or smart meter, and
    - a primary and secondary load control tariff for large business customers consuming more than 100MWh per year.
- Our Seasonal Time of Use tariffs for residential and small business customers have been retired, while our Seasonal Time of Use tariff for large business customers is closed to new customers.
- Increase in cost reflectivity and reduction in complexity in our charging parameters through the implementation of kVA denomination of demand charging for all SAC Large tariffs and removal of the excess kVAr charges from our CAC tariffs.

- Unmetered supply tariff will no longer have a fixed charge component and will be only be charge on volume basis in alignment with Energex.

Alternative Control Services

- Prices for security (watchmen) lighting services, provision of training for network related access and network related property services are regulated by the AER for the 2020-25 regulatory control period. These services were previously unregulated.
- A number of service fee descriptions and classifications have been amended to improve clarity and ensure alignment with Energex. Further, a number of services that were previously priced on a quotation basis have shifted to a fee basis.
- Introduction of new LED public lighting tariffs and LED versions of our existing tariffs to reflect the cost efficiencies found in LED lighting compared to conventional lighting.

Further information about changes to our network tariffs for Standard Control Services and Alternative Control Services from 1 July 2020 is set out in Section 5.

1.6 Structure of this document

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

Table 1: Pricing Proposal structure

Chapter	Title	Overview
1	Introduction	Provides an overview of the 2020-21 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 2020-21 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 2020-21 in accordance with the requirements of the NER and the AER's Distribution Determination.
4	Alternative Control Services	Outlines for 2020-21 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	Changes from the previous regulatory year	Describes the nature and extent of changes from 2019-20.
6	Adjustments to tariffs within 2020-21	Sets out the nature of any adjustments or variations to tariffs that could occur during 2020-21 and the basis on which it could occur.
7	Rates for 2020-21 compared to indicative rates in the TSS	Outlines any deviations in 2020-21 rates from the indicative rates provided in our December 2019 Revised TSS submission and explains any differences between them.
	Appendices	Provides additional supporting information, including: • All proposed Standard Control Services tariffs and tariff structures • The terms and conditions for load control tariffs • Compliance checklist • Glossary • Confidentiality template.

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

- Attachment 1 – 2020-21 Network Tariff Tables
- Attachment 2 – Indicative Pricing Schedule 2020-25
- Attachment 3 - Material Change (for Standard Control Services only)
- Attachment 4 – Confidential Tariff Approval Model 2020-21 (for Standard Control Services)

Where possible, these documents will be made publicly available.

1.7 Supporting network pricing documentation

In addition to this Pricing Proposal, we have published a number of related network pricing documents to assist network users, retailers and interested parties understand the development and application of tariffs and connection charges.[4] These documents are outlined in Table 2.

Table 2: Supporting network pricing documentation

Document	Overview
2020-25 Tariff Structure Statement	• Sets out the proposed tariff classes, tariffs and tariff structures for the 2020-25 period • Details how the proposed tariff classes, tariffs and tariff structures comply with the pricing principles • Describes the tariff setting process for Standard Control Services and Alternative Control Services • Provides details on Ergon Energy's tariff assignment policy • Provides indicative prices for the 2020-25 regulatory control period • Approved by the AER as part of the 2020-25 Distribution Determination
2020-21 Initial Pricing Proposal	• Explains how Ergon Energy's tariff classes, tariffs and tariff structures for Standard Control Services and Alternative Control Services in compliance with the requirements set out in Chapter 6 of the NER, the AER's Distribution Determination and our TSS • Provides proposed prices for 2020-21 • Submitted to the AER annually for approval
2020-21 Network Tariff Tables	• Provides Ergon Energy's 2020-21 prices for our Standard Control Services and Alternative Control Services developed in accordance with the requirements set out in the NER, the AER's Distribution Determination and our TSS • Submitted to the AER annually as part of the Pricing Proposal • Referred to as Attachment 1 in this Pricing Proposal
Connection Policy	• Sets out when a connection charge may be payable by retail customers or real estate developers and the aspects of the connection service for which a charge may be applied • Details how Ergon Energy calculates the capital contributions to be paid • Approved by the AER in 2020 as part of the 2020-25 Distribution Determination

[4] Link to Ergon Energy's website: www.ergon.com.au/network/network-management/network-pricing

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 control period (NER clause 6.18.2(b)(2) and (3)).

2.1 Tariff classes

In the NER, tariff classes are defined as 'a class of retail customers for one or more direct control services who are subject to a particular tariff or particular tariffs'. All customers who take supply from us for direct control services are a member of at least one tariff class.

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 Table 3: Tariff classes.

Table 3: 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 132kV, 110kV, 66kV or 33kV 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 are based 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.

Tariff class	Eligible customers
Note: a. Some existing customers coupled to the HV network at lower voltage levels will remain allocated 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 4: 2020-21 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	• Volume Night Controlled • Volume Controlled
	Large customer	• Demand Large • Demand Medium • Demand Small • Large Business Time of Use Demand • Seasonal Time of Use Demand • Large Business Primary Load Control	• Large Business Secondary Load Control
	Other	• Unmetered Supply • Solar FiT	
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 Customers (ICC)		• Standard ICC tariff • Non-standard ICC tariff	

Tariffs have three key defining characteristics:

- the charge (can also be called a 'charging component', 'tariff component' or 'tariff element')
- the parameters of the charge (specific characteristics that relate to the charge that influence how it is calculated), and
- the rate or price applied to each charge.

The types of charges and charging parameters used for our Standard Control Services are shown in Table 5. Each charge and charging parameter is selected and structured to provide signals to network users about the efficient use of the network. This is particularly the case for the demand and time of use-based tariffs. More detailed information on our charging parameters by tariff is available in our TSS.

Table 5: Types of charges and charging parameters 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 ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all primary and secondary tariffs.
Block usage (or volume)	Represented as a rate ($) per kWh. Different charges apply to each consumption block. • For IBT Residential the blocks are: 0<1,000kWh; 1,000kWh<6,000kWh and 6,000kWh<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.

Charge	Charging parameters	Application to tariffs
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.

The full list of tariffs, including their charging parameters, offered in 2020-21 are included in Appendix A: Proposed tariffs and charging parameters.

2.3 Tariff assignment and re-assignment process

Detailed procedures for the assignment and reassignment of customers to Standard Control Services tariff classes and tariffs are contained in our 2020-25 TSS. Consistent with the NER requirements (clause 6.18.1A(a)(2)), we will comply with these procedures in 2020-21.

We periodically review the assignment of customers to tariff classes and tariffs to ensure customers are assigned to the correct tariff class and tariff. For large customers connected at the 11kV network and above, demand and volume characteristics are reviewed annually, while connection assets and network configurations are reviewed periodically or on request.

The decision making for tariff class and tariff re-assignment is in line with that used for the assignment of customers to tariff classes and tariffs set out in the TSS. We ensure customers with similar characteristics are treated equitably by specifically taking into account the nature and extent of their usage and the nature of their connection to the network. For customers with demand levels that fluctuate frequently, we may apply a reasonable tolerance limit on tariff thresholds of 15% on an annualised consumption basis to mitigate frequent tariff re-assignment, and subsequently limit customer impact.

Finally, it should be noted that customers requesting a tariff re-assignment are allowed only one tariff change per 12-month period.[5] This ensures transaction costs are contained and pricing signals are not distorted by constant changes. However, this condition will not apply to customers who have opted in to the newly introduced Small Business Primary Load Control Tariff, the Large Business Primary Load Control Tariff and the Large Business Secondary Load Control Tariff. Customers on these tariffs will be permitted to opt out of their load control tariffs within the 12-month period.

[5] Such a tariff change is free of charge to customers.

3. Tariff levels for Standard Control Services

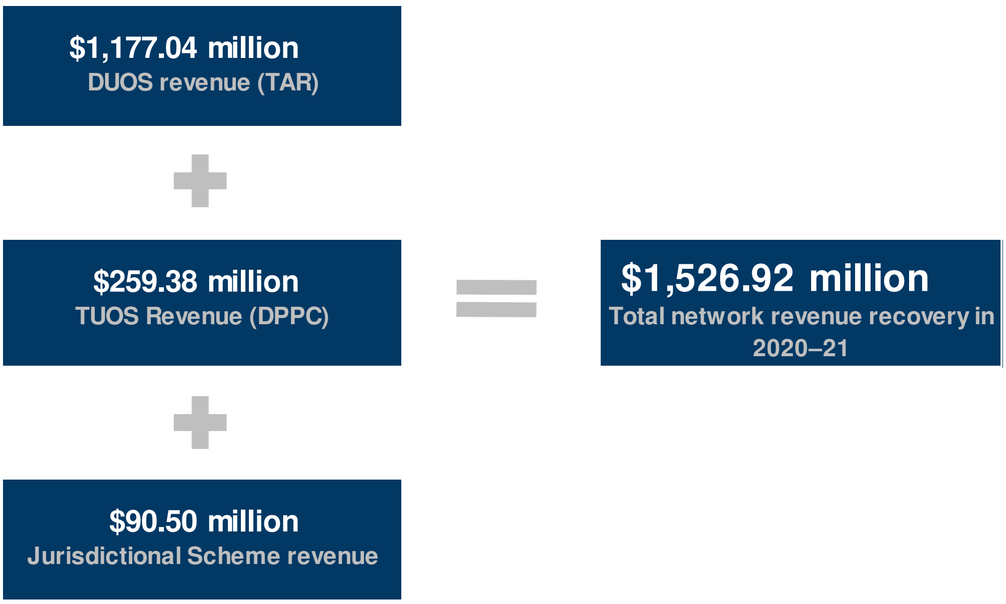
This chapter sets out how we have developed our 2020-21 network prices for Standard Control Services in compliance with the regulatory requirements in Chapter 6 of the NER, the AER's revenue determination and our approved TSS.

3.1 Total revenue requirement for 2020-21

In 2020-21, the total revenue that we will need to recover from network users (via our network tariffs) is approximately $1,527 million as shown in Figure 1. This amount includes:

- Distribution Use of System (DUOS) charges, which reflect Ergon Energy's electricity distribution costs,
- Designated Pricing Proposal (DPPC) charges (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.

Figure 1: Summary total network revenue for 2020-21



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

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 2020-21.

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:

$$DUoS\ Under\ and\ Overs\ True - Up_t = -(Opening\ Balance_t)(1 + WACC_t)^{0.5}$$

where:

$DUoS\ Under\ and\ Overs\ True - Up_t$ is the true-up for the balance of the DUoS unders and overs account in year t.

$Opening\ Balance_t$ 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.

6 All parameters are in nominal terms unless otherwise specified.

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

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. It will also include any end-of-period adjustments in regulatory year t.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[8] 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.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

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 s-factor reflects performance in year t-2 against STPIS targets set in this decision. 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.

The TAR, which reflects Ergon Energy's smoothed revenue requirement plus other annual adjustments, will be approximately $1,177 million in 2020-21. Detailed calculations are provided in Table 6.

In addition to the TAR, transmission charges[9] and jurisdictional scheme amounts (including FiT payments made under the Solar Bonus Scheme (SBS) and the AEMC levy)[10] are also recovered from customers.

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8 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

9 Transmission network charge are also known as DPPC or, previously, known as Transmission Use of System (TUOS) charges.

10 Jurisdictional scheme amounts will be passed through to customers in 2020-21.

The details of our revenue requirement for 2020-21 are presented in Table 6 below.

Table 6: 2020-21 Total Allowable Revenue calculations

Components	Amount ($m)	Comments
(a) Annual Revenue (AR_t)	$1,178.599	2020-21 annual smoothed expected revenue as per the amount in approved by the AER in their Final Decision
(b) STPIS (St)	$26.455	S-factor determined in accordance with the STPIS requirements.
Annual Smoothed Expected Revenue 2020-21 (AR_t)	**$1,205.054**	
Adjustments:		
DMIS carryover amount (It)	N/A	No longer applicable.
DUoS under/over recoveries (B_t)	-$28.015	Over recovery for 2018-19 returned to customers.
Total Annual Revenue (TAR_t)	**$1,177.038**	
Further adjustments:		
Jurisdictional Schemes	90.501	Includes Queensland SBS Jurisdictional Scheme and AEMC levy amounts.
TUoS (or DPPC)	**$259.378**	Transmission costs to be recovered in 2020-21
Total Revenue Requirement	**$1,526.918**	Total revenue that Ergon Energy will need to recover in 2020-21

Note:
Above figures represented to three decimals places for presentation purposes, the unrounded figure is used for calculations within the Tariff Approval Model

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
- provide entries in the DUOS unders and overs account for the most recently completed regulatory year (t-2), the current regulatory year (t-1) and the next regulatory year (t). For this Pricing Proposal, year t-2 is 2018-19, year t-1 is 2019-20 and year t is 2020-21.[11]

The AER also requires that Ergon Energy’s DUOS amounts for the most recently completed regulatory year (t-2) (i.e. 2018-19) be audited. We believe this requirement is met as the information provided is based on the information submitted and audited as part of the Annual Reporting Regulatory Information Notice (RIN). It should be noted that the amounts for the current regulatory year (t-1) are estimates and next regulatory year (t) are forecast amounts.

[11] Ergon Energy Determination Decision 2020 to 2025, Attachment 13 – Control Mechanisms, June 2020.

The unders and overs account is detailed in Table 7.

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

Unders/overs account element	2018-19 Year t-2 (actual) $	2019-20 Year t-1 (estimate) $	2020-21 Year t (forecast) $
(A) Revenue from DUOS charges	**$1,311,959,955**	**$1,290,532,068**	**$1,177,038,330**
(B) Less TAR for regulatory year =	**$1,284,147,453**	**$1,293,364,813**	**$1,205,053,524**
+ Adjusted annual smoothed revenues (AARt)	$1,306,448,909	$1,299,466,339	$1,178,598,706
+ Incentive scheme amounts (It) a	$26,129,087	$25,989,390	$26,454,819
+ Annual adjustments (Bt) b	-$45,974,864	-$32,090,916	$0
+ Cost pass through amount (Ct)	-$2,455,679	$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	**$27,812,502**	**-$2,832,745**	**-$28,015,195**
DUOS unders and overs account			
Nominal WACC (per cent)	6.015%	5.982%	4.285%
Opening balance	N/A	$28,636,723	$27,433,660
Interest on opening balance	N/A	$1,713,185	$1,175,396
Under/over recovery of revenue for regulatory year	$27,812,502	-$2,832,745	-$28,015,195
Interest on under/over recovery for regulatory year	$824,221	-$83,503	-$593,862
Closing balance	**$28,636,723**	**$27,433,660**	**$0**

3.2.2 Recovery of DUOS charges from generators

We note that clause 6.1.4(a) of the NER specifically prohibits DUOS charges being applied for the export of electricity generated by the user into our distribution network. As outlined in our TSS, embedded generators (EGs) will not incur DUOS charges for the export of electricity generated by the user into the distribution network. However, a DUOS fixed charge ($/day) applies to EGs. This charge reflects costs associated with connection assets and network user management services provided to EGs. These costs are incurred regardless of whether the EG exports electricity into our network.

Furthermore, EGs who are net importers of electricity will receive network charges only for their use of the network related to electricity import. Where customers are net generators and are exposed to kVA based demand charges, their export will be ignored in the calculation of their demand charges.

In the case of SACs with micro-generation facilities, these customers are assigned to the same network tariff for their supply to their connection point as any other network customer with similar load profile (i.e. in the absence of micro-generation facilities). They will however receive DUOS charges for their use of the network related to electricity import.

3.2.3 Forecast weighted average revenue

In accordance with clause 6.18.2(b)(4) of the NER, the expected weighted average revenue related to Ergon Energy's Standard Control Services tariff classes for 2019-20 and 2020-21 is shown in Table 8.

Table 8: Expected weighted average DUOS revenue by tariff class

Tariff class	Pricing zone	2019-20	2020-21	Change in weighted average revenue
ICC	East	$37,202,589	$37,415,659	0.6%
	West	$13,740,026	$13,282,445	-3.3%
	Mount Isa	$0	$0	0.0%
CAC	East	$70,211,521	$66,584,412	-5.2%
	West	$8,895,901	$9,968,181	12.1%
	Mount Isa	$0	$0	0.0%
SAC	East	$895,757,683	$808,347,501	-9.8%
	West	$253,847,166	$229,081,625	-9.8%
	Mount Isa	$13,699,818	$12,358,505	-9.8%
	Total	**$1,293,354,705**	**$1,177,038,330**	-9.0%

Note: All amounts are GST exclusive

3.3 Designated Pricing Proposal Charges

3.3.1 Background

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
- avoided transmission (TUOS) charges paid to eligible EGs
- payments made to other DNSPs for the supply of distribution services.

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

In accordance with clause 6.18.2(b)(6) of the NER, the DPPC amount to be passed on to customers must not exceed the estimated amount of the DPPC adjusted for any over or under recovery. We confirm that our DPPC charges do not include amounts relating to our revenue requirement, jurisdictional schemes or any other amounts recovered from other DNSPs.

3.3.2 Transmission costs

Designated pricing proposal charges 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 Price ($/month)
- Capped Customer TUOS Usage Price: Usage Capacity Price ($/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 Price (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.

Payments associated with avoided TUOS to eligible EGs by Ergon Energy reflect the avoided costs of upstream transmission network reinforcement. 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.

For 2020-21, avoided TUOS payments will generally be remitted in the form of a lump sum payment after 30 June 2021, similar to previous years.

The estimated total amount in avoided TUOS liability to EGs accrued in 2020-21 is included below in Table 9: DPPC unders and overs account.

3.3.3 Recovery of DPPC (revenue)

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

<u>ICC tariffs</u>

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.

For ICC connections on site-specific charges, Ergon Energy takes into account the fact that customers can be supplied from different connection points depending on switching arrangements. Charges are apportioned based on the actual Transmission Connection Points the connection is supplied from. A weighted average methodology is applied for each of the Transmission Connection Points so that these site-specific connections have cost reflective DPPC charges.

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.

3.3.4 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 which provides amounts for the revenue recovered from DPPC and associated payments to Powerlink for the most recently completed regulatory year (t-2), the current regulatory year (t-1) and the next regulatory year (t). This annual unders and overs process ensures that any difference between the revenue recovered from customers and the actual transmission-related expenses is returned to (or recovered from) our customers so that we recover no more and no less that the DPPC amounts we incurred.

The unders and overs account in Table 9 sets out Ergon Energy's over recovery based on information lodged and audited in our 2018-19 RIN.

DPPC amounts for the regulatory year (t-1) are estimates and the amounts for the regulatory year (t) are forecast amounts.

Table 9: DPPC unders and overs account

Unders/overs account element	2018-19 Year t-2 (actual) $	2019-20 Year t-1 (estimate) $	2020-21 Year t (forecast) $
(A) Revenue from designated pricing proposal charges (DPPC)	**$254,166,965**	**$254,454,253**	**$259,378,230**
(B) Less DPPC related payments for regulatory year =	**$252,779,983**	**$256,713,114**	**$258,549,091**
+ DPPC to be paid to Transmission Network Service Provider	$246,627,485	$245,128,116	$253,129,669
+ Avoided TUoS/DPPC payments	$2,234,695	$1,764,102	$2,239,469
+ Inter-distributor payments	$4,188,945	$3,866,593	$3,179,952
+ Annual adjustments	-$271,142	$5,954,303	
(A minus B) Under/over recovery of revenue for regulatory year	**$1,386,982**	**-$2,258,861**	**$829,139**
DPPC unders and overs account			
Nominal WACC (per cent)	6.015%	5.982%	4.285%
Opening balance	N/A	$1,428,085	-$811,928
Interest on opening balance	N/A	$85,435	-$34,787
Under/over recovery of revenue for regulatory year	$1,386,982	-$2,258,861	$829,139
Interest on under/over recovery for regulatory year	$41,103	-$66,586	$17,576
Closing balance	**$1,428,085**	**($811,928)**	**($0)**

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

- the Solar Bonus Scheme which obligates Ergon Energy to make FiT payments for energy supplied into our distribution network from specific micro-embedded generators[12]
- the energy industry levy covering a proportion of the Queensland Government's funding commitments for the AEMC which, under our Distribution Authority we are obligated to pay since 2016.

During the three-year period from 1 July 2017 to 30 June 2020 these costs were funded by Queensland Government via a fixed grant covering the estimated jurisdictional scheme amounts.

It should be noted that from 1 July 2020, the jurisdictional scheme amounts (Solar Bonus Scheme and other amounts) will be funded by electricity customers within each distribution area. As a result, jurisdictional scheme amounts are included in the calculation of our network charges for 2020-21.

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

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

schemes for the most recently completed regulatory year t-2, being 2018-19, the current regulatory year t-1, being 2019-20 and the regulatory year t, being 2020-21.

The unders and overs account presented in Table 10 is based on information lodged (and audited) in our 2018-19 RIN.

Table 10: Jurisdictional scheme amounts unders and overs account

Unders/overs account element	2018-19 Year t-2 (actual) $	2019-20 Year t-1 (estimate) $	2020-21 Year t (forecast) $
(A) Revenue from jurisdictional schemes	**$94,922,178**	**$92,907,000**	**$90,501,360**
(B) Less jurisdictional scheme payments for regulatory year =	**$94,922,178**	**$92,907,000**	**$90,501,361**
+ Jurisdictional scheme 1 payments	$94,815,140	$92,800,000	$90,384,082
+ Jurisdictional scheme 2 payments	$107,038	$107,000	$117,279
(A minus B) Under/over recovery of revenue for regulatory year	**$0**	**$0**	**-$1**
Jurisdictional scheme amount unders and overs account			
Nominal WACC (per cent)	6.015%	5.982%	4.285%
Opening balance	N/A	$0	$0
Interest on opening balance	N/A	$0	$0
Under/over recovery of revenue for regulatory year	$0	$0	-$1
Interest on under/over recovery for regulatory year	$0	$0	$0
Closing balance	**$0**	**$0**	**($1)**

3.5 Demand, energy and customer number forecast

Our network demand, energy and customer number forecasting methodologies are set out in our 2019-20 to 2023-24 Distribution Annual Planning Report[13] (refer to Chapter 5). Energy forecasts are prepared at the total network level, at customer category levels and for certain individual 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.

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

3.5.1 Forecast underpinning this submission

As part of our 2020-25 Regulatory Proposal, in December 2019 we provided the AER with the key drivers underpinning our demand and energy forecasts and expected customer numbers throughout the 2020-25 regulatory control period. The forecast numbers used to prepare the proposed 2020-21 prices provided with this Pricing Proposal are consistent with the numbers provided to the AER in December 2019.

We recognise that COVID-19 may impact future demand and energy usage. While it is currently too early to assess and quantify the likely impact, we note that our demand and energy forecast numbers may change as further information becomes available. Due to the uncertainty associated with our forecast, we anticipate that the indicative rates for 2021-22 to 2024-25 submitted as part of the 2020-21 Pricing Proposal will differ from the proposed rates provided in the pricing proposals in future years.

The forecast demand, energy and customer numbers for 2020-21 are included in Table 11.

Table 11: 2020-21 demand, energy and customer numbers forecasts[14]

Tariff class	ICC	CAC	SAC	Total
Average Demand (MVA)	823	472	N/A	**1,295**
Undiversified Average Maximum Demand (MW)	N/A	N/A	4,850	**4,850**
Volume (GWh)	4,038	1,381	8,063	**13,482**
Customer numbers	108	182	777,786	**778,076**

Notes:

Average Maximum Demand is undiversified, assuming all customers are utilising the network at the same time.

3.5.2 Impact on Under/Over Recovery

In consideration of the above, the forecast underpinning this submission may contribute to an under or over recovery as full year actual revenue for 2020-21 becomes available. To compound this issue, we believe the impact of COVID-19 will be also evident in the 2019-20 actual revenue.

Similar to our forecast, it is premature to assess the likely impact to revenue, however we draw attention to likely under or over recovery impacts in years 2021-22 and 2022-23. We will provide

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

further updates to potential impacts in our final 2020-21 Pricing Proposal as more information becomes available.

3.6 Compliance with the Pricing Principles

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

3.6.1 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.

As noted in our TSS and the accompanying Explanatory Notes, we interpret these costs in the following manner:

- Stand-alone costs for a tariff class are the theoretical costs of establishing and maintaining infrastructure to service a single tariff class as if no other tariff classes needed to be served. They represent the upper bound costs of providing a service for a particular tariff class. Assuming that no other tariff classes use network infrastructure means that the economies of scale and scope from using a shared network to serve customers across multiple tariff classes are ignored.
- Avoidable costs are the costs which would be avoided by Ergon Energy not providing a distribution service to a particular tariff class, assuming all other tariff classes continued to be served. For example, if we were to cease providing services to CACs, the avoidable cost methodology assesses the extent to which our costs would be reduced as a result.

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. Details of our approach to determining the avoidable and stand-alone costs for our Standard Control Services are provided in the TSS Explanatory Notes. Table 12 demonstrates that our total revenue for 2020-21 from each tariff class falls between the stand-alone and avoidable cost estimates.

Table 12: Avoidable costs, expected revenue and stand-alone costs for Standard Control Services for 2020-21

Tariff class	Pricing zone	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(e) compliance
ICC	East	$35,543,175	$37,415,659	$294,545,471	Yes
	West	$13,090,660	$13,282,445	$65,129,782	Yes
	Mount Isa	$0	$0	$0	
CAC	East	$62,958,687	$66,584,412	$708,260,550	Yes
	West	$9,642,763	$9,968,181	$343,300,989	Yes
	Mount Isa	$0	$0	$0	
SAC	East	$435,700,610	$808,347,501	$814,628,881	Yes
	West	$141,728,021	$229,081,625	$232,292,133	Yes
	Mount Isa	$0	$12,358,505	$12,358,505	Yes

Note: All amounts are GST exclusive.

3.6.2 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 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.

It should be noted that neither the calculation of LRMC nor the application of LRMC to tariff-setting are prescribed in the NER and, therefore, can be undertaken in a number of different ways. Chapter 2 of our 2020-25 TSS and chapter 7of the TSS's Explanatory Notes set out the methodology we have adopted to calculate LRMC and our approach to incorporating these values in our tariff structures and rates.

Application of LRMC in tariff setting

In our tariff-setting for 2020-21 we have applied the approach to LRMC detailed in our TSS. This approach includes:

Selection of appropriate charging parameter:

The LRMC values have been incorporated 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 tariffs.

Strength of the LRMC signal:

- For our 'legacy tariffs': These tariffs and associated tariff structures 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.
- Cost reflective tariffs for SAC tariff class: The new Transitional Demand tariffs for SAC Small customers incorporate a muted LRMC signal compared to the standard demand tariffs. This is intended to allow our mass market customers to adjust to tariffs they may not be familiar with and/or to mitigate the potential for network charge impact. For SAC Large customers we have

introduced newtime of use demand tariffs that place a more appropriate weight on signalling the LRMC of using the distribution network at peak times.

- For our CAC and ICC tariff classes, the LRMC signal is made through the demand charge parameter.

Table 13 provides the LRMC values for each voltage level for 2020-21. These figures are based on those included in the TSS.

Table 13: Undiversified LRMC values by voltage levels for 2020-21

Voltage level	Pricing zone	$/kW p.a.	$/kVA p.a.
Sub-transmission	East	N/A	$ 68.40
	West	N/A	$ 219.45
22/11kV Bus	East	N/A	$ 151.20
	West	N/A	$ 372.60
22/11kV Line	East	N/A	$ 151.20
	West	N/A	$ 372.60
LV	East	$ 251.11	$ 226.00
	West	$ 733.33	$ 660.00
	Mt Isa	$ 251.11	$ 226.00

3.6.3 Least distortionary recovery of 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 2020-21 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.

Our 2020-25 TSS and accompanying Explanatory Notes further discuss how our tariff structures ensure we recover our revenue allowance in the least distortionary way, consistent with clause 6.18.5(g) of the NER.

3.6.4 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. We have supported our 2020-25 TSS with an extensive customer impact analysis developed by the University of New South Wales (refer to Attachment B to the Revised TSS submitted on 10 December 2019).

In developing our LRMC-based tariffs, our objective has been to present the LRMC component through parameters which are as cost reflective and least distortionary to the pricing signal as possible to enable customer responses that support optimal use of the network. In addition, our tariffs have been established with a view to developing LRMC tariff parameters that customers are likely and able to respond to, while choosing and calibrating residual recovery parameters that are less likely to distort the LRMC signals or encourage inefficient use or by-pass of the network.

Except for ICCs, customers have the option to move to more cost reflective LRMC-based tariffs. This provides customers with more choice and control in how they are charged for their use of the network.

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 2020 to 2025 period. These measures include:

- An over-riding ceiling on individual SAC customer impacts of an additional 2.5% higher than the annual change in DUOS will apply (i.e if the change in DUOS is -4% for example, the maximum individual customer impact would be -1.5%).
- 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 grace period for existing residential and small business customers with smart meters who are still assigned to less cost reflective legacy tariffs before they are re-assigned to the new Transitional demand tariffs and allowing new residential and small business to temporarily access legacy IBT tariffs.

In establishing the 2020-21 tariffs, we have continued to apply these measures.

The tables below present our customer impact analysis for 2020-21 and demonstrate that almost all customers are expected to experience a decrease in their DUOS charges in 2020-21 compared with their 2019-20 charges, arising from our lower allowable revenues.

Table 14: Customer impact for average customers on SAC tariffs

Nominal ($) – DUOS change

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2019-20 DUOS ($)	2020-21 DUOS Nom ($)	Annual DUOS change ($)	Annual DUOS change (%)	Comment
Residential (<100MWh pa)							
IBT Residential East (ERIB)	3.93	4,886	692.44	604.00	-88.44	-12.8%	
Residential Demand East (ERDEM)			N/A	651.05	-41.39	-6.0%	Compared to IBT Residential
Residential Transitional Demand East (ERTDEM)			N/A	608.56	-83.88	-12.1%	Compared to IBT Residential
Residential ToU Energy East (ERTOUE)			N/A	620.38	-72.06	-10.4%	Compared to IBT Residential
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.							
Small Business (<100MWh pa)							
IBT Business East (EBIB)	6.80	7,465	994.67	852.54	-142.13	-14.3%	
Small Business Demand East (EBDEM)			N/A	1,013.46	18.78	1.9%	Compared to IBT Business
Small Business Transitional Demand East (EBTDEM)			N/A	873.20	-121.47	-12.2%	Compared to IBT Business
Small Business ToU Energy East (EBTOUE)			N/A	867.58	-127.09	-12.8%	Compared to IBT Business
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.							
Large Business (>100MWh pa)							
Demand Small East (EDS)	57.53	407,104	25,021.67	20,770.14	-4,251.52	-17.0%	
Demand Medium East (EDM)	172.00	656,894	63,676.68	54,933.15	-8,743.53	-13.7%	
Demand Large East (EDL)	607.00	1,746,934	182,872.70	155,219.93	-27,652.77	-15.1%	
Large Business Time-of-Use Demand East (ELTOUD)			N/A	153,315.10	-29,557.60	-16.2%	Compared to Demand Large

Nominal ($) – NUOS change

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2019-20 NUOS ($)	2020-21 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)	Comment
Residential (<100MWh pa)							
IBT Residential East (ERIB)	3.93	4,886	802.22	812.06	9.84	1.2%	
Residential Demand East (ERDEM)			N/A	842.65	40.43	5.0%	Compared to IBT Residential
Residential Transitional Demand East (ERTDEM)			N/A	800.16	-2.06	-0.3%	Compared to IBT Residential
Residential ToU Energy East (ERTOUE)			N/A	812.43	10.21	1.3%	Compared to IBT Residential
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.							
Small Business (<100MWh pa)							
IBT Business East (EBIB)	6.80	7,465	1,130.04	1,110.43	-19.61	-1.7%	
Small Business Demand East (EBDEM)			N/A	1,248.56	118.52	10.5%	Compared to IBT Business
Small Business Transitional Demand East (EBTDEM)			N/A	1,108.31	-21.73	-1.9%	Compared to IBT Business
Small Business ToU Energy East (EBTOUE)			N/A	1,132.77	2.73	0.2%	Compared to IBT Business
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.							
Large Business (>100MWh pa)							
Demand Small East (EDS)	57.53	407,104	31,902.19	28,130.36	-3,771.83	-11.8%	
Demand Medium East (EDM)	172.00	656,894	75,797.49	67,814.74	-7,982.75	-10.5%	
Demand Large East (EDL)	607.00	1,746,934	217,009.24	192,667.35	-24,341.88	-11.2%	
Large Business Time-of-Use Demand East (ELTOUD)			N/A	190,132.88	-26,876.36	-12.4%	Compared to Demand Large

Real ($) – DUOS change

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2019-20 DUOS ($)	2020-21 DUOS Real ($)	Annual DUOS change ($)	Annual DUOS change (%)	Comment
Residential (<100MWh pa)							
IBT Residential East (ERIB)	3.93	4,886	692.44	592.08	-100.36	-14.5%	
Residential Demand East (ERDEM)			N/A	638.28	-54.16	-7.8%	Compared to IBT Residential
Residential Transitional Demand East (ERTDEM)			N/A	596.56	-95.88	-13.8%	Compared to IBT Residential
Residential ToU Energy East (ERTOUE)			N/A	608.17	-84.27	-12.2%	Compared to IBT Residential
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.							
Small Business (<100MWh pa)							
IBT Business East (EBIB)	6.80	7,465	994.67	836.13	-158.54	-15.9%	
Small Business Demand East (EBDEM)			N/A	994.14	-0.54	-0.1%	Compared to IBT Business
Small Business Transitional Demand East (EBTDEM)			N/A	856.42	-138.25	-13.9%	Compared to IBT Business
Small Business ToU Energy East (EBTOUE)			N/A	850.90	-143.77	-14.5%	Compared to IBT Business
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.							
Large Business (>100MWh pa)							
Demand Small East (EDS)	57.53	407,104	25,021.67	20,393.78	-4,627.89	-18.5%	
Demand Medium East (EDM)	172.00	656,894	63,676.68	53,939.38	-9,737.29	-15.3%	
Demand Large East (EDL)	607.00	1,746,934	182,872.70	152,413.75	-30,458.95	-16.7%	
Large Business Time-of-Use Demand East (ELTOUD)			N/A	150,543.34	-32,329.36	-17.7%	Compared to Demand Large

Real ($) – NUOS change

SAC Tariffs	Demand (kW/year)	Usage (kWh/year)	2019-20 NUOS ($)	2020-21 NUOS Real ($)	Annual NUOS change ($)	Annual NUOS change (%)	Comment
Residential (<100MWh pa)							
IBT Residential East (ERIB)	3.93	4,886	802.22	796.38	-5.84	-0.7%	
Residential Demand East (ERDEM)			N/A	826.42	24.20	3.0%	Compared to IBT Residential
Residential Transitional Demand East (ERTDEM)			N/A	784.69	-17.52	-2.2%	Compared to IBT Residential
Residential ToU Energy East (ERTOUE)			N/A	796.75	-5.47	-0.7%	Compared to IBT Residential
Note: Actual Residential customer profile selected as close to average customer with annual consumption of 4,877kWh as possible.							
Small Business (<100MWh pa)							
IBT Business East (EBIB)	6.80	7,465	1,130.04	1,089.37	-40.68	-3.6%	
Small Business Demand East (EBDEM)			N/A	1,224.99	94.95	8.4%	Compared to IBT Business
Small Business Transitional Demand East (EBTDEM)			N/A	1,087.28	-42.76	-3.8%	Compared to IBT Business
Small Business ToU Energy East (EBTOUE)			N/A	1,111.30	-18.74	-1.7%	Compared to IBT Business
Note: Actual Small Business customer profile selected as close to average customer with annual consumption of 7,457kWh as possible.							
Large Business (>100MWh pa)							
Demand Small East (EDS)	57.53	407,104	31,902.19	27,620.98	-4,281.21	-13.4%	
Demand Medium East (EDM)	172.00	656,894	75,797.49	66,588.18	-9,209.31	-12.1%	
Demand Large East (EDL)	607.00	1,746,934	217,009.24	189,184.41	-27,824.82	-12.8%	
Large Business Time-of-Use Demand East (ELTOUD)			N/A	186,695.75	-30,313.49	-14.0%	Compared to Demand Large

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 2019-20 and 2020-21 are presented below. The average impact figures have been calculated based on the revenue we would recover using the 2020-21 approved rates relative to the revenue we would recover using the 2019-20 rates.

Table 15: Average customer impacts for the ICC and CAC tariff classes (nominal)

Tariff Class	Impact	DUOS annual impact (%)	Jurisdictional schemes annual impact (%)	DPPC annual impact (%)	NUOS annual impact (%)
ICC	Average Impact	-9.5%	100.0%	-9.5%	-1.2%
CAC	Average Impact	-10.6%	100.0%	5.8%	-4.0%

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

The network prices used for the customer impact analysis exclude GST.

These DUOS and NUOS prices are the AER approved prices for 2019-20 and the proposed 2020-21 prices (included in Attachment 1 of with this Pricing Proposal).

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 2019-20 and 2020-21.

3.6.5 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.

3.6.6 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 2020-21 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 C: Compliance Checklist.

3.7 2020-21 Standard Control Services rates

The proposed network rates for 2020-21 for all Standard Control Services are included in Attachment 1 provided with this Pricing Proposal.

Section 7.1 provides further explanation on the differences between our proposed 2020-21 rates and the corresponding indicative prices developed as part of the 2020-25 TSS.

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 (or schedule of prices) 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 2020-21 are set out below.

Table 16: 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
	  ○ 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) lighting • Non-standard network data requests • Customer requested provision of electricity network data • Third party funded network alternations

4.2 Tariffs and charging parameters

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. The charge and charging arrangements that have been adopted for our 2020-21 Alternative Control Services tariffs are shown in Table 17 and Attachment 1.

The tariff structures and charging parameters are consistent with the approach set out in our TSS.

Table 17: 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.

4.2.1 Alternative Control Services tariffs for each tariff class

In accordance with clause 6.18.2(b)(2) of the NER, our Pricing Proposal sets out the Alternative Control Services which have been specified in our TSS. Each of our Alternative Control Services tariffs for 2020-21 are set out in Attachment 1.

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 2020-21.

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 included in Table 16 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. Annual prices will change by inflation and the X factor from years 2 to 5 of the 2020-25 regulatory control period, and the 2020-21 prices are set such that the net present value of the revenue stream resulting from this price path over the 2020-25 regulatory control period equals the net present value of the building block revenue requirement for the 2020-25 regulatory control period.

The AER's prescribed price cap formula will be used to adjust prices in subsequent years (2021-2025).

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 18: 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 subsequent years (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", and
- The type of public lighting technology (i.e. conventional or LED).

From 1 July 2020, a new public lighting tariff, NPL4 will apply 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. NPL4 tariff sits between the NPL1 tariff (where we have funded all assets) and the NPL2 tariff (where the entirety of the public lighting assets is funded by customers).

The public lighting tariffs offered in 2020-21 are set out in the table below.

Table 19: 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:

Equation 3: Cost build-up formula for fee-based services in first year of regulatory control period

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.

Prices in subsequent years of the regulatory control period will be based on the cost build-up developed for 2020-21, escalated for CPI and X factor using the AER's approved 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 4: 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 our TSS and the AER's Distribution Determination Decision, 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:

- As this is the first year of the regulatory control period the proposed 2020-21 prices reflect the AER's Determination decision.
- In accordance with the Distribution Determination, for the remaining years of the regulatory control period (2021-25) the prices will be escalated annually for CPI and X factor using AER's approved rates.

Quoted services:

- The Distribution Determination sets out the approved hourly labour rates for 2020-21 to be utilised for the purpose of Equation 4.
- For the remaining years of the regulatory control period the base labour rates will be escalated annually for inflation, by $(1+\Delta CPI_t)(1-X_t^i)$.

4.6 Compliance with the Pricing Principles

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 7.3 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. However, as highlighted in Section 1.4.4, a number of our Alternative Control Services are impacted by Schedule 8 of the *Electricity Regulation 2006*. Consequently, we make further adjustments to the tariffs derived under the Pricing Proposal process to satisfy the maximum prices set out in Schedule 8. This means the prices customers will be actually charged in 2020-21, may be lower than the prices contained in Attachment 1.

Once Schedule 8 is published for the 2020-21 regulatory year, we will update the rates for Alternative Control Services applicable to reflect the Schedule 8 maximum price caps. These updated prices are those customers will be charged in 2020-21.

4.7 2020-21 Alternative Control Services rates

The proposed rates for 2020-21 for all Alternative Control Services tariffs are provided in Attachment 1 with our Pricing Proposal.

Section 7.2 provides further explanation on the differences between our proposed 2020-21 rates and the corresponding indicative prices developed as part of the 2020-25 TSS.

5. Changes from the previous regulatory year

This Pricing Proposal contains several changes since 2019-20. As 2020-21 is the first year of the 2020-25 regulatory control period the changes in this Pricing Proposal reflect our 2020-25 TSS and the information provided by the AER in the Distribution Determination (NER Clause 6.18.2(b)(8)).

5.1 Changes to the revenue requirement

Table 20 below outlines changes in our revenue between 2019-20 and 2020-21, including:

- adjustments to the TAR components
- DPPC
- Jurisdictional schemes.

Table 20: Summary of revenue adjustments

Component		2019-20 values	2020-21 values	Reasons for change
CPI	%	1.78	1.84	
X factor	%	2.2781	N/A	X factor updated in the PTRM
STPIS	$m	25.99	26.45	The applicable S-factor for the year is 2.24%. It has been adjusted to reflect the previous year's S-factor.
DUOS under/over recover	$m	($32.09)	($28.02)	DUOS over recovery in 2018-19 to be returned to customers in 2020-21
DUOS	$m	$1,293.36	$1,177.04	-8.99% decrease in the Total Allowable Revenue between 2019-20 and 2020-21 in accordance with the AER's Final Determination.
Jurisdictional schemes	$m	$0.00	$90.50	Jurisdictional scheme amount recovered through network charges in accordance with the requirement set out in the NER
DPPC (TUOS)	$m	$256.71	$259.38	1.04% increase in Powerlink charges between 2019-20 and 2020-21 in accordance with the AER's Final Determination.

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

5.2 Network tariff changes for Standard Control Services

As noted in Section 1.5 of this Pricing Proposal, there will be several changes to our network tariffs from 1 July 2020. In accordance with our TSS, we have made the following changes to Standard Control Services network tariffs:

- We have consolidated our tariff classes (EG and SAC tariff class) to improve alignment with the voltage level of a customer's connection to the network and simplify the tariff class assignment process.

SAC Tariff Class

<u>Changes affecting Residential and Small business customers:</u>

- We have introduced a new default tariff, Transitional Demand, for new residential and small business customers with digital metering and existing customers who initiate a meter change.

  However, our legacy IBT tariffs will be temporarily available to all new and existing customers until 1 July 2021. For information about the tariff assignment process for 2020-21 refer to our TSS.

- Two new optional tariffs, ToU Energy tariff and Demand tariff, will be available for customers with smart meters from 1 July 2020. These new tariffs and the Transitional Demand tariffs all have the same non-seasonal, evening peak charging window, from 4pm to 9pm.
- We have introduced the new Wide Inclining Fixed tariff (WIFT) which establishes a structure for SAC Small Business customers with basic meters and annual consumption above 20MWh.
- A new Primary Load Control tariff will be available for Small Business customers with a basic or smart meter from 1 July 2020.
- Our Seasonal Time of Use tariffs for residential and small business customers have been retired and customers re-assigned to either the IBT or the Transitional Demand tariff depending on their metering.

Changes affecting Large Customers:

- We have introduced a new Large Business ToU Demand tariff for customers with smart meters. From 1 July 2020 this tariff will be the default tariff for new demand large business customers and is available on an opt-in basis to existing large business customers.
- Our Seasonal Time of Use tariff for large business customers is closed to new customers.
- Two new additional opt-in load control tariffs (a primary and a secondary tariff) will be available for Large Business customers from 1 July 2020.
- We have implemented kVA denomination of demand charging for all SAC Large customer tariffs from 1 July 2020, however where customer metering does not support kVA billing data being available, a kW denominated version of our tariffs will continue to be available.

CAC and ICC tariff class

- We have changed our tariff class definitions to include scope for CAC customers to be classified and priced as ICC customers where the nature of the customer's connection to the network, and/or usage of the network make average prices inappropriate.
- We have removed the excess kVAr charges from 1 July 2020.

Our TSS Explanatory Notes (Section 6) provide further information and the rationale for the changes noted above.

5.3 Alternative Control Services changes

In accordance with out TSS, we have made the following amendments to our Alternative Control Services since 2019–20:

- A number of service fee descriptions and classifications have been amended to improve clarity and ensure alignment with Energex and the AER's Service Classification Guide. Further, a number of services that were previously priced on a quotation basis have shifted to a fee basis. Refer to Attachment 1 for a list fee based services.
- Prices for security (watchmen) lighting services, provision of training for network related access and network related property services are regulated by the AER for the 2020-25 regulatory control period. These services were previously unregulated.

- Public lighting services:
  - Introduction of LED versions of the current public lighting tariffs (NPL1 and NPL2) to reflect the cost efficiencies found in LED lighting compared to conventional lighting.
  - Introduction of a new public lighting tariff, NPL4, to allow for customers to initiate a switch to LED without having to contribute the whole asset or wait for the end-of-life of the asset. Where a customer funds the replacement of the luminaire and lamp to LED, they will move from the existing conventional NPL1 tariff to the new NPL4 tariff.

6. Adjustments to tariffs within 2020-21

6.1 Standard Control Services tariff adjustments

Variations or adjustments to our network tariffs may occur 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:

- 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 2020-21, 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 course of the regulatory year.

We note that in circumstances where we are required to make a change to our TSS during a regulatory control period as a result of an event outside our control which could not reasonably have been foreseen, we may request from the AER the right to amend our TSS in accordance with clause 6.18.1B of the NER. If the AER is satisfied that the change to the TSS is warranted, we may be able to adjust the charge to the tariff in accordance with the revised TSS approved by the AER.

6.2 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 course of the 2020-21 regulatory year.

7. Prices for 2020-21 compared to the indicative prices in the TSS

We note that the NER obligation (Clause 6.18.2(b)(7A)) only requires us to provide and explain material differences for our Direct Control Services (i.e. Standard Control Services DUOS and Alternative Control Services). While the 2020-25 Indicative Pricing Schedule provided with our December 2019 Revised TSS also provides indicative prices for DPPC (or TUOS), we have focused our explanation mainly on the differences in our DUOS prices.

7.1 Differences in Standard Control Services pricing levels

To satisfy clause 6.18.2(b)(7A) of the NER we have included a comparison between the proposed prices for 2020-21 and the indicative 2020-21 price submitted with our December 2019 Revised TSS submission. This price comparison is included in Attachment 3 provided with this Pricing Proposal.

This Pricing Proposal is based on the approved 2020-25 TSS. Deviations from the indicative prices for 2020-21 are due to:

- updates to allowed revenue – The main driver of the difference is change in the revenue requirement use to calculate the proposed tariffs for 2020-21. The rates in the TSS pricing schedule were based on Ergon Energy's revised regulatory proposal while the proposed prices submitted with this Pricing Proposal are based on the revenue requirement in the AER's Determination Decision.
- slight rebalancing 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.

When looking at the price level comparisons provided, a degree of caution should be exercised as the rates of the charging parameters 'contribute' in varying amount to the NUOS revenue recovery at the overall tariff level. That is, each charging parameter within a tariff has a weighting (or percentage) of the overall NUOS revenue recovery. This means that a large percentage change on a specific charging parameter that only has a small weighting of overall NUOS revenue recovery will have a smaller impact on the overall cost outcome of the tariff than the increase on the single charge parameter would indicate.

With respect to materiality, we have referenced an increase of greater than 15 per cent in an individual rate/charge and greater than 2 per cent in the indicative weighted outcome as the threshold to explain differences. As shown in Attachment 3, a limited number of tariffs and rates met this criteria. These include:

- CAC tariffs:
  - DUOS connection unit charge decreased across all tariffs in line with updated customer information.
  - DPPC volume charge increased across all tariffs in transmission pricing zones T2 and T3 compared to that forecast in our revised TSS. This increase is a result of updates to Powerlink's final transmission costs for 2020/21.
- SAC tariffs:
  - Our DUOS volume charges, as the residual cost component, have changed due to the update in forecast customer uptake across our tariff suite (for example, our SAC Large

volume charges in the East pricing zone have reduced for all tariffs as a result of a rebalancing of forecast quantities associated with the new Large Business ToU tariff).

  - The final transmission payments for 2020/21 are higher that the forecast used in our TSS, resulting in higher DPPC volume charges in transmission pricing zones T2 and T3.

7.2 Differences in Alternative Control Services pricing levels

We confirm that our Alternative Control Services prices, provided in Attachment 1 as part of this Pricing Proposal, are consistent with those presented in the AER's Distribution Determination.

The differences between the indicative 2020-21 prices for Alternative Control Services included as part of the December 2019 Revised TSS submission and the prices included in this Pricing Proposal are reflective of the AER's final decision.

7.3 Updated indicative pricing levels

In accordance with Clause 6.18.2 of the NER, our latest estimates of indicative Standard Control Services and Alternative Control Services prices for the 2020-25 regulatory control period are provided in Attachment 2 of our final Pricing Proposal for 2020-21. These prices are based on tariff structures detailed in our TSS.

Appendix A: Proposed tariffs and charging parameters

Consistent with our TSS, the table below sets out the tariffs and tariff structures for Standard Control Services offered in 2020-21.

Tariff	Code	Status for 2020-21	Charging parameter	Units	ToU Charging timeframes
Tariff class: SAC					
Residential					
Residential Demand	RDEM	Opt-in for new and existing customers with smart meters	Fixed	$/day	Peak Demand: 4pm-9pm Weekdays* and Weekends
			Peak Demand kW	$/kW/month	
			Volume	$/kWh	
Residential Transitional Demand	RTDEM	Default for new customers Opt-in for existing customers with smart meters	Fixed	$/day	Peak Demand: 4pm-9pm Weekdays* and Weekends
			Peak Demand kW	$/kW/month	
			Volume	$/kWh	
Residential ToU Energy	TRTUOE	Opt-in for new and existing customers with smart meters	Fixed	$/day	Evening (peak): 4pm-9pm Weekdays* & Weekends Night (shoulder): 9pm-9am Weekdays* & Weekends Day (off-peak): 9am-4pm Weekdays* & Weekends
			Volume Evening Charge	$/kWh	
			Volume Night Charge	$/kWh	
			Volume Day Charge	$/kWh	
Residential Inclining Block (IBT)	RIB	Default for existing customers with basic meters Opt-in for new and existing customers with smart meters	Fixed	$/day	N/A
			Volume Block 1 (0<1,000kWh)	$/kWh	
			Volume Block 2 (1,000<6,000kWh)	$/kWh	
			Volume Block 3 (6,000<100,000kWh)	$/kWh	
Small Business					
Small Business Demand	BDEM	Opt-in for new and existing customers with smart meters	Fixed	$/day	Peak Demand: 4pm-9pm Weekdays*
			Peak Demand kW	$/kW/month	
			Volume	$/kWh	
Small Business Transitional Demand	BTDEM	Default for new customers Opt-in for existing customers with smart meters	Fixed	$/day	Peak Demand: 4pm-9pm Weekdays*
			Peak Demand kW	$/kW/month	
			Volume	$/kWh	
Small Business Time-of-Use Energy	BTOUE		Fixed Band 1 (0<20,000kWh/year)	$/day	Evening (peak): 4pm-9pm Weekdays*
			Fixed Band 2 (20,000<40,000kWh/year)	$/day	

Tariff	Code	Status for 2020-21	Charging parameter	Units	ToU Charging timeframes
		Opt-in for new and existing customers with smart meters	Fixed Band 3 (40,000<60,000kWh/year)	$/day	Night (shoulder): 9pm-9am Weekdays*; 4pm-9pm Weekends Day (off-peak): 9am-4pm Weekdays* & Weekends
			Fixed Band 4 (60,000<80,000kWh/year)	$/day	
			Fixed Band 5 (>80,000kWh/year)	$/day	
			Volume Evening Charge	$/kWh	
			Volume Night Charge	$/kWh	
			Volume Day Charge	$/kWh	
Small Business Inclining Block (IBT)	BIB	Default for existing customers with basic meters with consumption below 20MWh per year	Fixed	$/day	N/A
			Volume Block 1 (0<1,000kWh)	$/kWh	
			Volume Block 2 (1,000<20,000kWh)	$/kWh	
			Volume Block 3 (20,000<100,000kWh)	$/kWh	
Small Business Wide Inclining Fixed Tariff	BWIF	Default for customers with a basic meters with consumption exceeding 20MWh per year	Fixed Band 1 (0<20,000kWh/year)	$/day	N/A
			Fixed Band 2 (20,000<40,000kWh/year)	$/day	
			Fixed Band 3 (40,000<60,000kWh/year)	$/day	
			Fixed Band 4 (60,000<80,000kWh/year)	$/day	
			Fixed Band 5 (>80,000kWh/year)	$/day	
			Volume	$/kWh	
Residential and Small Business Controlled Load					
Small Business Primary Load Control	BPLC	Opt-in	Fixed	$/day	N/A
			Volume	$/kWh	
Volume Controlled	VC	Secondary tariff	Volume	$/kWh	N/A
Volume Night Controlled	VN	Secondary tariff	Volume	$/kWh	N/A
Unmetered					
Unmetered	U		Volume	$/kWh	N/A
Large Business					
Large Business Time-of-Use Demand	LTOUD	Default for new demand large business customers	Fixed	$/day	Peak Demand: 4pm-9pm Weekdays*
			Actual Demand Peak	$/kVA/month	
			Excess Demand	$/kVA/month	
			Volume	$/kWh	
Demand Small	DST		Fixed	$/day	N/A
			Actual Demand	$/kW of AMD/month	

Tariff	Code	Status for 2020-21	Charging parameter	Units	ToU Charging timeframes
		Default for new demand small customers	Actual Demand	$/kVA of AMD/month	
			Volume	$/kWh	
Demand Medium	DMT	Default for new demand medium customers	Fixed	$/day	N/A
			Actual Demand	$/kW of AMD/month	
			Actual Demand	$/kVA of AMD/month	
			Volume	$/kWh	
Demand Large	DLT	Opt-in	Fixed	$/day	N/A
			Actual Demand	$/kW of AMD/month	
			Actual Demand	$/kVA of AMD/month	
			Volume	$/kWh	
Seasonal Time-of-Use Demand	STOUD	Closed to new customers	Fixed	$/day	Summer peak demand charge: 10am-8pm during the months of December, January and February, Weekends and Weekdays* Demand Off Peak: All other times.
			Actual Demand Peak (>20kW)	$/kW of AMD/month	
			Actual Demand Off-peak (>40kW)	$/kW of AMD/month	
			Volume Peak	$/kWh	
			Volume Off-peak	$/kWh	
Large Business Controlled Load					
Large Business Primary Load Control	LPLC	Opt-in	Fixed	$/day	N/A
			Volume	$/kWh	
Large Business Secondary Load Control	LSLC	Secondary tariff	Volume	$/kWh	N/A
Tariff class: CAC**					
66kV	C66	Default for new and existing customers connected at 66kV	Fixed	$/day	N/A
			Connection Unit	$/day/connection unit	
			Capacity	$/kVA of AD/month	
			Actual Demand	$/kVA/month	
			Volume	$/kWh	
33kV	C33	Default for new and existing customers connected at 66kV	Fixed	$/day	N/A
			Connection Unit	$/day/connection unit	
			Capacity	$/kVA of AD/month	
			Actual Demand	$/kVA/month	

Tariff	Code	Status for 2020-21	Charging parameter	Units	ToU Charging timeframes
			Volume	$/kWh	
22/11kV Bus	C22B	Default for new and existing customers connected at 22/11kV Bus	Fixed	$/day	
			Connection Unit	$/day/connection unit	
			Capacity	$/kVA of AD/month	
			Actual Demand	$/kVA/month	
			Volume	$/kWh	
22/11kV Line	C22L	Default for new and existing customers connected at 22/11kV Line	Fixed	$/day	
			Connection Unit	$/day/connection unit	
			Capacity	$/kVA of AD/month	
			Actual Demand	$/kVA/month	
			Volume	$/kWh	
Seasonal ToU Demand 11 or 22kV Bus	TOUT	Opt-in for customers connected at 11kV or 22kV Bus	Fixed	$/day	Summer peak demand charge: 10am to 8pm during the months of December, January and February, Weekends and Weekdays* Demand Off Peak: All other times.
			Connection Unit	$/day/connection unit	
			Capacity Charge Off-Peak	$/kVA of AD/month	
			Actual Demand Charge Peak	$/kVA/month	
			Volume Charge Off-Peak	$/kWh	
Seasonal ToU Demand 11 or 22kV Line	TOUT	Opt-in for customers connected at 11kV or 22kV Line	Fixed	$/day	Summer peak demand charge: Maximum kVA demand recorded 10am to 8pm during the months of December, January and February, Weekends and Weekdays* Demand Off Peak: All other times.
			Connection Unit	$/day/connection unit	
			Capacity Charge Off-Peak	$/kVA of AD/month	
			Actual Demand Charge Peak	$/kVA/month	
			Volume Charge Off-Peak	$/kWh	
Seasonal ToU Demand 33 or 66 kV	TOUT	Opt-in for customers connected at 33kV or 66kV	Fixed	$/day	Summer peak demand charge: Maximum kVA demand recorded 10am to 8pm during the months of December, January and February, Weekends and Weekdays* Demand Off Peak: All other times.
			Connection Unit	$/day/connection unit	
			Capacity Charge Off-Peak	$/kVA of AD/month	
			Actual Demand Charge Peak	$/kVA/month	
			Volume Charge Off-Peak	$/kWh	
Tariff class: ICC					
Standard ICC**	ICC	Default	Fixed	$/day	
			Capacity	$/kVA of AD/month	

Tariff	Code	Status for 2020-21	Charging parameter	Units	ToU Charging timeframes
			Demand	$/kVA/month	
			Volume	$/kWh	
Non-standard ICC	ICC	Optional	Fixed	$/day	
			Capacity	$/kVA of AD/month	
			Demand	$/kVA/month	
			Volume	$/kWh	

Notes:
* Weekdays include government gazetted full day public and bank holidays i.e. State, regional and local public holidays.
** CAC tariffs and Standard ICC tariff are not offered in the Mount Isa region

Appendix B: 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 or a minimum of 8 hours per day, (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 remove / reinstate supply through 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 on the network, it may delay the approval process. The	• Any customer, regardless of their metering type, can access the tariff. • Customer MUST be in an area that relevant network business is able to remove / reinstate supply through the distributor's standard load control signalling technology. • Eligibility for this tariff may require a network assessment. If a network assessment is required by the DNSP to identify any

			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.	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) • Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the QECM requirements, is the	• 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 be supplied by the customer. (as per QECM) • This tariff will be removed from any premises where the customer has the ability	• 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) • Any additions and alterations to the electrical installation to enable load control equipment to be	• 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 contactor is required, it shall be supplied by the customer. (as per QECM) • This tariff will be removed from any premises where

	responsibility of the customer eg contactors and meter wiring.	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.	installed, as per requirements of the QECM, is the responsibility of the customer eg contactors and meter wiring.	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) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during a supply interruption under this tariff (vii) Pumping and irrigation equipment (viii) Battery Energy Storage Systems (BESS)	• 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. (iii) Electric Vehicle Supply Equipment (EV Chargers). (iv) Pool filtration systems. (v) Heat pump 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) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during	• 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. (vi) Other appliances (e.g. washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a

	(ix) Solar PV (x) Other equipment as approved by us.	(vi) Other appliances (e.g. washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during a supply interruption under this tariff. (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)	a supply interruption under this tariff. (vii) Pumping and irrigation equipment. (viii) Battery Energy Storage Systems (BESS). (ix) Solar PV. (x) Other equipment as approved by us	different tariff for the same purpose during the supply interruption under this tariff. (vii) Pumping and irrigation equipment. (viii) Battery Energy Storage Systems (BESS). (ix) Solar PV (x) Other equipment as approved by us

Appendix C: Compliance Checklist

Table 21: 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.	Our Pricing Proposal was submitted to the AER by the appropriate date
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.	Not applicable in 2020-21
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 and 2.2 (Standard Control Services) Section 4.1 and 4.2 (Alternative Control Services) The 2020-21 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 6.1 (Standard Control Services) Section 6.2 (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.	Chapter 7 Attachment 3 sets out the material differences between the 2020-21 indicative pricing levels (as set out in our TSS) and the proposed 2020-21 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.	Chapter 5 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:	Section 3.6.1 (Standard Control Services)

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
	(1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those retail customers.	Section 4.6 (Alternative Control Services) Section 2.2 and 6.3 of the TSS
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 3.6.2 (Standard Control Services) Section 4.6 (Alternative Control Services) Section 2.3 and 6.3 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 3.6.3 (Standard Control Services) Section 4.6 (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 3.6.4 and 5.2 (Standard Control Services) Section 5.3 (Alternative Control Services) Further information on how we meet this pricing principle is also available in our TSS
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 3.6.5 (Standard Control Services) Section 4.6 (Alternative Control Services) Section 2.4 and 6.3 of the TSS

Rule	Requirement	Relevant Section in Pricing Proposal or other documents
6.18.5(j)	A tariff must comply with the NER and all applicable regulatory instruments.	Section 1.4 and Section 3.6.6 (Standard Control Services) Section 4.6 (Alternative Control Services)
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 3.3.3
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 D: Glossary

Table 22: Acronyms and abbreviations

Abbreviation	Description
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CAC	Connection Asset Customers
Capex	Capital Expenditure
CPI	Consumer Price Index
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal Charges (previously known as TUOS)
DUOS	Distribution Use of System
EG	Embedded Generators
ENA	Energy Network Australia
FiT	Feed-in Tariff (Solar FiT) under the Queensland Solar Bonus Scheme
HV	High Voltage
ICC	Individually Calculated Customers
LCC	Large Customer Connection
LRMC	Long Run Marginal Cost
LV	Low Voltage
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
NTC	Network Tariff Code
NUOS	Network Use of System
Opex	Operating and Maintenance Expenditure
PV	Photovoltaic (Solar PV)
RAB	Regulatory Asset Base
SAC	Standard Asset Customers
STPIS	Service Target Performance Incentive Scheme
TAR	Total Annual Revenue
TNCP	Transmission Network Connection Point
TNSP	Transmission Network Service Provider

Abbreviation	Description
TSS	Tariff Structure Statement
TUOS	Transmission Use of System (now known as DPPC)
WACC	Weighted Average Cost of Capital

Table 23: 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 24: 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

Table 25: Definitions of terminology used throughout this document

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.
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.
Basic meter		Basic accumulation meters are defined as a meter that is only capable to recording the customers' energy consumption during the billing period.
Business hours	BH	8 am to 5 pm, Monday to Friday.
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).

Term	Abbreviation / Acronym	Definition
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).
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 distribution Determination document published by the AER in its role as Ergon Energy's economic regulator that provides for distribution charges to increase during Ergon Energy's Regulatory Control Period. 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.

Term	Abbreviation / Acronym	Definition
High Voltage	HV	Refers to the network at 11 kV or above.
Inclining Block Tariff	IBT	A type of network tariff where the price per kWh increases as consumption thresholds are crossed during a particular time period.
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 with installed capacity greater than or equal to 30 kVA.
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.
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.

Term	Abbreviation / Acronym	Definition
		Power factor = kW / kVA
Price path		Outlines the escalation factors to be applied to the initial price over the *Regulatory Control Period.*
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.
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 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 by taking into account volume forecasts, CPI, X Factor, STPIS and Capital Contributions. 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.

Term	Abbreviation / Acronym	Definition
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 submitted its 2020-25 TSS proposal to the AER in December 2019. Once approved, the 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's 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.
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.

Appendix E: 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.	2020-21 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	2020-21 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.