DRAFT DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 15
Alternative control services

October 2019

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: EnergyQueensland2020@aer.gov.au

AER reference: 62728

Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AER	Australian Energy Regulator
Capex	capital expenditure
CCP	Consumer Challenge Panel
CCP 14	Consumer Challenge Panel, sub-panel 14
CESS	capital expenditure sharing scheme
CPI	consumer price index
Distributor	distribution network service provider
F&A	framework and approach
LED	Light Emitting Diode
NEL	national electricity law
NEM	national electricity market
NER or the rules	national electricity rules
NSP	network service provider
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RIN	regulatory information notice
WACC	weighted average cost of capital

15 Alternative control services

This attachment sets out our draft decision on prices Ergon Energy is allowed to charge customers for the provision alternative control services: ancillary network services, public lighting services and metering services.

Alternative control services are customer specific or customer requested services and so the full cost of the service is attributed to that particular customer, or group of customers, benefiting from the service. We set service specific prices to provide a reasonable opportunity to the distributor to recover the efficient cost of each service from customers using that service. This is in contrast to standard control services where costs are spread across the general network customer base.

Revenue from alternative control services represents around 10.4 per cent of Ergon Energy's total regulated revenue.[1]

15.1 Draft decision

Our draft decision is to reject Ergon Energy's proposed charges for ancillary network services[2] provided on a fee basis and not substitute any charges pending Ergon Energy's revised proposal. We recommend that Ergon Energy undertake a review of its proposed fees and modelling and consult with its stakeholders in preparing its revised proposal. Notwithstanding our draft decision to reject Ergon Energy's proposed charges for ancillary network services, we have assessed its proposed labour rates and service times. We accept some of Ergon Energy's proposed labour rates as efficient, but reject a number of other labour rates and substitute them with our own. Our draft decision on labour rates is listed in appendix A.

For public lighting services, our draft decision is to accept Ergon Energy's proposed LED rollout and Asset Management Plan, but reject Ergon Energy's proposed approach to capital and operating expenditure. We have replaced the WACC, labour escalators, and other related inputs consistent with our methodology for standard control services. Further, our draft public lighting decision addresses stakeholder submissions.

For metering services, our draft decision is to accept Ergon Energy's building block approach and metering asset base, but reject Ergon Energy's proposed approach to capital and operating expenditure. We have replaced the WACC, labour escalators, and other related inputs consistent with our methodology for standard control services.

The detail of our draft decision is set out in the following sections:

---

1 AER calculation based on Ergon Energy, *17.053 - 2020-25 regulatory determination RIN template - January 2019, 3.1 - Revenue*.

2 Ancillary network services include network ancillary services, auxiliary metering services and non-standard connection services.

- 15.4 – Ancillary network services
- 15.5 – Public lighting
- 15.6 – Metering services.

15.2 Ergon Energy's proposal

Ancillary network services

To establish charges for ancillary network services Ergon Energy proposed a cost build-up approach with prices calculated on either a fee or quotation basis dependent on the nature of the service.[3] Ergon Energy's regulatory proposal indicated that a 'capital allowance' would form part of this cost build-up, including as an additional component of the pricing formula for quoted services. In response to information requests, Ergon Energy clarified that the 'capital allowance' would not be included for quoted services, and should be considered as a type of overhead for fee-based services.[4]

Ergon Energy developed its prices using internal labour rates approved by the AER for the current regulatory period and escalated to 2020–21, contractor costs, overheads and materials for 2020–21, task time, crew size and labour type based on historical practice and internal assessments.[5] Ergon Energy also proposed changing service fee descriptions to improve clarity and consistency with Energex.[6] While Ergon Energy initially claimed confidentiality over its labour rates it later agreed that they could be made public.

Ergon Energy proposed shifting the pricing of many of its ancillary network services from a quotation basis in the 2015–20 regulatory control period to a fee basis for the 2020–25 regulatory control period, to improve pricing transparency for customers and reduce transaction costs.[7] Ergon Energy's original proposal and pricing model contained 451 service fees covering a range of fee permutations.[8] Through our assessment process Ergon Energy revised its model by combining fees, removing fee permutations and correcting modelling errors. This resulted in the revised model submitted in late June containing 329 fees.[9]

Public lighting services

For public lighting services, Ergon Energy proposed:

---

3 Ergon Energy, *1.004 - Regulatory proposal 2020-25*, January 2019, p. 125.

4 Ergon Energy, *Response to information request #014 - Ancillary network services,* 8 April 2019; Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 10 May 2019.

5 Ergon Energy, *1.004 - Regulatory proposal 2020-25*, January 2019, p. 125.

6 Ergon Energy, *1.004 - Regulatory proposal 2020-25*, January 2019, p. 125.

7 Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 20 May 2019.

8 Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JAN19 PUBLIC.*

9 Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC.*

- a target for its LED rollout of 47 per cent at the end of the 2020–25 regulatory control period[10]
- new tariffs to differentiate LED customers to those of conventional lighting[11]
- to split its asset base across conventional and LED lighting and use separate building block approached for each[12]
- capital expenditure trended forward based on growth rates of conventional/LED lighting[13]
- a base-step-trend approach to operating expenditure, with conventional and LED lighting apportioned based on their respective opening asset bases[14]
- a smoothed revenue resulting in price increases being limited to CPI for years 2 to 5 of the 2020–25 regulatory control period.[15]

Metering services

For metering services, Ergon Energy proposed capital expenditure of only $0.38 million during the 2020–25 regulatory control period for new meters, as it is no longer responsible for meter provision/installation in its distribution area except for the Mt Isa-Cloncurry network.[16] However, Ergon Energy also proposed capital expenditure of $16.71 million for non-network allocation of assets.[17] Ergon Energy proposed a base-step-trend approach to operating expenditure, reflecting adjustments for productivity and cost allocation changes, as well as the metering 'churn' of customers switching to advanced type 1-4 meters.[18] Ergon Energy proposed a small increase in prices in the first year of the 2020–25 regulatory control period, with price increases being limited to CPI for years 2 to 5.[19]

15.3 Assessment approach

The price cap control mechanism that we apply to assess the efficient costs of alternative control services may use elements of the building block model for standard control services, but there is no requirement to apply the building block model exactly as prescribed in the NER.[20] Full details of our draft decision on the form of control mechanism and control mechanism formulas is set out in attachment 13 of this draft decision.

10 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 11.
11 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 20.
12 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 14.
13 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 15.
14 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, pp. 15-16.
15 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 18.
16 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 6.
17 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 6.
18 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, pp. 7-8.
19 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 9.
20 NER, cl. 6.2.6(c).

Ancillary network services

Our assessment approach for ancillary network services involves a bottom up cost assessment. Labour costs are the major input in the cost build-up of prices for ancillary network services. Therefore, our assessment focusses on comparing Ergon Energy's proposed labour rates against maximum total labour rates, which we consider efficient.

Where Ergon Energy's proposed labour rates exceed our maximum efficient labour rates, we apply our maximum efficient labour rates to determine prices. We follow this assessment process for services provided on a fee or quotation basis, as Ergon Energy's proposed labour rates are the same for both sets of ancillary network services. Section 15.4.2 discusses our maximum total labour rates.

We also assess the proposed times taken to perform each ancillary network service as well as the escalators Ergon Energy applied, as these are also cost inputs which impact the final price for some services. Our assessment of these inputs is informed by benchmarking against inputs applied by other distributors and the recommendations of our consultant, Marsden Jacob Associates (Marsden Jacob).

Public lighting services

To determine prices for public lighting services we assess Ergon Energy's public lighting model, consider historical data and benchmark proposed costs against other NEM distributors and against independent data and information. Specifically, we assess proposed labour rates, luminaire failure rates, overheads and input assumptions used to derive proposed public lighting charges.

Metering services

To assess proposed metering prices we analyse the Post-tax Revenue Model (PTRM), studying historical data and benchmark costs against other NEM distributors. We specifically focus on the operating expenditure costs on a category basis and how these costs have trended over time.

We also have regard to stakeholder submissions on any aspect of alternative control services.

15.4 Ancillary network services

Ancillary network services share the common characteristic of being non-routine services provided to individual customers as requested. Ancillary network services are either charged on a fee or quotation basis, depending on the nature of the service.

We determine fee based service price caps for the next regulatory control period as part of our determination, based on the cost inputs and the average time taken to perform each service. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty. By comparison, prices for quoted services are based on quantities of labour and materials, with the quantities dependent on a particular task. Prices for quoted services are determined at the time of a customer's enquiry and reflect the individual requirements of the customer’s service request. For this reason, it is not possible to list prices for quoted services in our decision, however our draft decision sets labour rates to be applied to ancillary network services provided on a quotation basis.

Ergon Energy advised that a comparison of prices from the 2015–20 regulatory period to its proposal is difficult as many services that were previously priced on a quotation basis have shifted to a fee basis, there have been changes to service categories/descriptions to align services with Energex, and there have been changes to Ergon Energy's cost allocation method.[21] Appendix A includes a non-exhaustive list of ancillary network services we accept that Ergon Energy may charge on a quotation basis.

15.4.1 Ancillary network services—Draft decision

Form of control – Ancillary network services

Our draft decision is to maintain our final F&A position to apply price caps to ancillary network services as the form of control. Under a price cap form of control, we set a schedule of prices for the first year of the regulatory control period, 2020–21. For the subsequent years of the regulatory control period, the prices for ancillary network services charged on a fee basis are determined by adjusting the previous year's prices by the formula set out in attachment 13 - control mechanisms.

Consistent with our previous decisions, we have applied a labour escalator as the X-factor. We have substituted our labour escalator for Ergon Energy's proposed labour forecasts.[22] Our proposed X-factors for this draft decision are set out in Table 15-11 in appendix A. Our draft decision is to set separate X-factors for fees relating to the installation of type 6 meters for the Mt Isa-Cloncurry network, based on whether they are urban/short rural or long rural/isolated. We discuss this at section 15.4.2.

Fee-based and quoted services

Our draft decision is to reject Ergon Energy’s proposed charges for all ancillary network services provided on a fee basis. Ergon Energy indicated (as part of Energex's response to an information request), that it intends to change some of its underlying service assumptions that affect a small number of fees as part of its revised proposal.[23] Because Ergon Energy made significant changes to its ancillary network services proposal through our assessment process, as well as correcting modelling errors, we recommend Ergon Energy undertake a review of its proposed fees and modelling. It should also engage with stakeholders in preparing its revised proposal. This is not to say that we consider all of Ergon Energy's proposed ancillary network service fees are inefficient. Rather, we consider that there will be greater benefit in Ergon Energy reviewing its ancillary network service proposal in aggregate rather than an ongoing

---

21 Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 20 May 2019.

22 Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC.*

23 Energex, *Response to information request #060 - ANS - significant price increases*, 21 August 2019.

iterative approach. For interested stakeholders, the fees rejected can be found in the model published with this decision.[24]

Ergon Energy indicated its support for this approach and willingness to work with us in preparing its revised proposal.

In relation to labour rates used for services charged on both a fee and quotation basis, our draft decision is to:

- accept Ergon Energy's proposed labour rates for services provided on a fee or quotation basis for its labour categories: professional managerial; power worker (PW); technical service person; electrical system designer; supervisor; and apprentice.
- reject Ergon Energy's proposed labour rates for its labour categories: admin; para-professional; system operator; and tech/ PW/Admin and substitute the maximum labour rate recommended by our consultant.
- accept Ergon Energy's overtime labour rates as they fall within our consultant's maximum recommended overtime mark-up of 175 per cent, except for labour categories where we have substituted our maximum labour rate. For these labour categories (admin; para-professional; system operator; and tech/PW/Admin), our draft decision is to substitute a labour rate of 175 per cent of our ordinary time labour rate draft decision.

Table 15.1 sets out our draft decision maximum labour rates (which include on-costs and overheads) that Ergon Energy should apply in calculating charges for ancillary network services. Table 15-9 in appendix A contains our draft decision labour rates for overtime hours.

Table 15.1 AER draft decision - hourly labour rates (incl. on-costs and overheads, $2020–21) - ordinary hours

Ergon Energy labour category	Ergon Energy proposed implied[1] total hourly rate (base plus on-costs plus overheads)	AER labour category[2]	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads)[3]
Admin Employee	$131.32	Admin	$77.00
Professional Managerial[4]	$205.72	Project Manager	$205.72
Power Worker	$142.64	Field Worker	$142.64
Technical Service Person	$174.16	Technical Specialist	$174.16

[24] AER Draft Decision - *EGX ERG 15.009 Fee-based and quoted services model - ACS - PUBLIC* - October 2019.

Ergon Energy labour category	Ergon Energy proposed implied[1] total hourly rate (base plus on-costs plus overheads)	AER labour category[2]	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads)[3]
Electrical System Designer	$161.58	Engineer	$161.58
Supervisor	$192.84	Project Manager	$192.84
Para-Professional	$188.64	Admin	$77.00
Apprentice	$106.52	Field Worker	$106.52
System Operator	$231.12	Senior Engineer	$225.08
Tech/PW[5]	$158.40	Tech/PW[5]	$158.40
Tech/PW/Admin[5]	$149.37	Tech/PW/Admin[5]	$131.27

Notes:

1: AER calculation based on Ergon Energy's labour (including on-cost) figures and overhead rates contained in Ergon Energy's fee-based and quoted services model. Note that these figures are marginally different to those in the Marsden Jacob report which looked at $2019–20.

2: Based on Marsden Jacob report. These labour categories are for comparison purposes only

3: Calculated by escalating Marsden Jacob's recommended maximum labour rates for 2019–20 by the AER's forecast inflation rate.

4: Marsden Jacob recommended that we reject Ergon Energy's proposed 2019–20 labour rate for professional managerial. Our analysis of Ergon Energy's proposed 2020–21 labour rate shows it should be accepted.

5. The labour rates for these labour categories are an average of the labour rates for the underlying labour categories. While the AER does not have a specific matching labour category we have taken a similar approach and applied the average of our draft decision labour rates for the relevant categories.

Source: AER calculations; Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC.*

We also accept Ergon Energy's proposed travel time for ancillary network services provided on a fee basis of two hours for long rural/isolated feeders and twenty minutes for urban/short rural feeders.[25]

We also note that under Schedule 8 of the *Electricity Regulation 2006 (Qld),* some ancillary network services are price-capped, and these prices take precedence over our decision.[26]

[25] Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC - 'Travel time inputs' worksheet,*

[26] While there are only eight price-capped ancillary network services under the *Electricity Regulation 2006 (Qld),* these flow through to the permutations of the ancillary network services Ergon Energy proposed. The *Electricity Regulation 2006 (Qld)* also stipulates that prices for customers on long rural/isolated feeders should be the same as the prices for customers on urban feeders.

Shift of ancillary network services from from a quotation basis to fee basis (including fee permutations)

Ergon Energy proposed shifting many of its ancillary network services that it currently charges on a quotation basis to a fee basis for the 2020–25 regulatory period. It also proposed a number of fee permutations for the same service in a similar manner to Energex, resulting in a significant list of fees. This included fee permutations based on the time of service delivery being during business hours; anytime hours; and after hours; with the latter two being charged at the same rate. Through our assessment process, Ergon Energy significantly reduced its fee permutations (including its usage of the anytime hours permutation), and provided justification that its pricing approach was appropriate and cost reflective. Ergon Energy also adjusted its pricing of other fee permutations and corrected modelling issues. Our draft decision is to accept Ergon Energy's introduction of a range of additional service permutations charged on a fee basis for 2020–25 and its usage of the anytime hours fee permutations, noting however that we are rejecting prices for all ancillary network services provided on a fee basis.

Security lighting services

Ergon Energy proposed charging security lighting on a quotation basis.[27] However, Ergon Energy later clarified that it proposed to only charge security lighting installation costs on a quotation basis, but ongoing maintenance, operation and replacement of security lighting assets on a fee basis.[28] Ergon Energy submitted that it was not able to propose fees at this stage as it is reviewing its approach to security lighting against Energex's.[29] Ergon Energy advised that it intends to submit an updated security lighting model as part of its revised proposal which will be similar to its 2015–20 model, updated for our draft decision.[30]

Our draft decision is to accept charging for security lighting installation on a quotation basis, and charging for the ongoing costs on a fee basis in line with Ergon Energy's submission during our assessment process. However, our draft decision does not include any fees for security lighting services because we have not received Ergon Energy’s revised proposal and security lighting model.

15.4.2 Ancillary network services—Reasons for draft decision

For ancillary network services we review the key inputs in determining the price for the service including:

- Underlying labour rates
- Time taken to perform the service

---

[27] Ergon Energy, *15.006 - Alternative control services 2020-25*, January 2019, p. 26.

[28] Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

[29] Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

[30] Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

- Any material and vehicle costs associated with providing the service
- Overheads.

In considering the above inputs we had regard to maximum reasonable benchmark labour rates developed by our consultant, Marsden Jacob, which we consider are efficient. Marsden Jacob also undertook benchmarking of the time taken for the most common services.

By comparing the maximum benchmark labour rates to Ergon Energy's proposed labour rates and benchmark times taken to perform services, as developed by Marsden Jacob, we were able to assess Ergon Energy's proposed charges for ancillary network services charged on a fee basis against a maximum efficient charge.

A summary of Marsden Jacob's report and recommendations is in Figure 15.1.

Figure 15.1 Summary of Marsden Jacob's report to the AER - Review of alternative control services

We engaged Marsden Jacob to provide advice in relation to estimates of reasonable maximum total labour rates for Energex, Ergon Energy and SA Power Networks' 2020–25 proposed ancillary network services, and to benchmark certain ancillary network services provided on a fee basis. This report is an extension of Marsden Jacob's September 2018 report for the AER that considered the NSW distributors, Evoenergy, TasNetworks and Power and Water Corporation. Marsden Jacob had regard to the methodology and service benchmarks in that report in undertaking this new report.[1]

Marsden Jacob observed that although distributors use different labour category names and descriptions, the types of labour used to deliver ancillary network services broadly falls into five categories – administration; technical services; engineers; field workers; and senior engineers.[2] For the purposes of this review, Marsden Jacob also added a 'project manager' category.[3]

Using these categories Marsden Jacob developed benchmark labour rates for each distributor based on *Hays 2018–19 Energy sector and office support salary data* against which the efficiency of the proposed labour rates could be assessed.

In assessing the reasonableness of proposed labour rates, Marsden Jacob 'normalised' the rates provided by each distributor and separated them as:[4]

1. Raw labour – based on the Hays salary data with an escalator of 2.5 per cent applied to account for wage inflation and another escalator of 2.5 per cent applied to reflect Hays rates only shifting in $5000 increments.[5]
2. On-costs – to cover basic leave entitlements and standard on-costs including superannuation, workers compensation and payroll tax.[6]
3. Overheads – to cover all additional costs. Overall, Marsden Jacob recommended a maximum overhead rate of 61 per cent. Marsden Jacob also accepted the inclusion of an explicit profit margin, however where identified this allocation was benchmarked within the overall overhead allowance.[7]

In aggregate, these elements are referred to as the 'total labour rate', which is expressed as an hourly rate.

Based on its review, Marsden Jacob recommended maximum reasonable benchmark labour rates. These were subsequently revised through an addendum to its report, which is discussed further below. Marsden Jacob recommended that we apply these maximum labour rates to arrive at a maximum price for any ancillary network services that it did not benchmark.[8]

The maximum hourly labour rates include the highest of the Hays salary rates for each labour category. Marsden Jacob noted that while these are reasonable maximum rates, more efficient rates may be gained by reference to a different point in the Hays salary bands. For our next determination for these distributors, Marsden Jacob recommended the AER consider reducing the maximum labour rates to reflect efficiency frontier benchmarks rather than the highest of the Hays rates for each labour category.[9] We note Marsden Jacob's recommendation in the context of future determinations. For the purposes of this draft decision, we consider the maximum reasonable rates recommended by Marsden Jacob (as revised) are efficient.

Consistent with its previous report, Marsden Jacob recommended that overtime rates be charged at no more than 1.75 times the total labour rate.[10]

Addendum to the Marsden Jacob report

Following consideration of the impact of the Hays 2019–20 report,[11] we engaged Marsden Jacob to provide revised recommended maximum labour rates. We also asked Marsden Jacob to analyse revised labour rates provided by SA Power Networks following identification of a modelling error. In the addendum, Marsden Jacob continued to apply a 2.5 per cent escalator to the raw labour rates to reflect that Hays rates tend to only increase in increments of $5000 and relevant labour rates have only shifted a little (or not at all), in recent surveys.[12]

Marsden Jacob's revised recommended maximum labour rates are shown in Table 15.2.

Table 15.2 Revised maximum total hourly rates (base plus on-costs plus overheads), $2019–20

	SA Power Networks	Ergon Energy/Energex
Administrative Officer	$84.98	$75.16
Project Manager	$169.97	$202.36
Field Worker[1]	$144.64	$176.10
Technical Specialist	$169.97	$190.79
Engineer	$158.64	$173.45
Senior Engineer	$181.30	$219.70

Source: Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator - Addendum*, August 2019, Table 6, p. 8.

Notes: 1 Field worker rate includes an allowance of $20 for a vehicle as an additional overhead.

References:

1. Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, p 1, 4, 7. 14.
2. Ibid., pp. 2-3.
3. Ibid., p. 3.
4. Ibid., p. 3.
5. Ibid., p. 3.
6. Ibid., p. 3.
7. Ibid., p. 3.
8. Ibid., p. 10.
9. Ibid., p. 1.
10. Ibid., p. 10.
11. Available from www.hays.com.au/salary-guide/.
12. Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator - Addendum*, August 2019, p. 4.

Regulatory treatment of overheads and cost allocation

In its discussion of maximum overhead rates, Marsden Jacob noted capping the overhead rate may have unintended consequences for the broader cost allocation method.[31]

We considered the objectives of our Cost Allocation Guideline.[32] A distributor's cost allocation method sets out the principles and policies for attributing costs to, or allocating costs between, the categories of distribution services a distributor provides. Hence, in approving a distributor's cost allocation method we approve the methodology it uses to allocate costs. This does not equate to approving the costs.

The approval of actual costs is subject to applicable requirements set out in the NER. Proper application of the cost allocation method does not indicate whether the distributor's expenditure, including overheads, is at efficient levels or otherwise reflects the requirements of the NER, having regard to the revenue and pricing principles and the national electricity objective. By extension, proper application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

Fee based and quoted services

Ergon Energy submitted revised pricing models for ancillary network services to us in April[33] and June[34] 2019 to address modelling issues, update service assumptions and to respond to our information requests. Consequently, Ergon Energy's revised pricing model and charges significantly differ to those initially proposed.

Ergon Energy subsequently advised that the revised June 2019 model still contained modelling errors as it applied the incorrect overhead rate to materials.[35] This modelling error impacts on Ergon Energy's fees for type 6 meter installation (both new and additional/replacement) in the Mount Isa-Cloncurry network. In response to an information request by Energex, we were also advised that Ergon Energy intends to change some of its underlying service assumptions in its revised proposal for a small number of ancillary network services.[36]

Origin Energy's submission called on us to scrutinise Ergon Energy's proposed fees for some services as they varied considerably from Ergon Energy's 2019–20 approved

---

31 Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, p. 7.

32 AER, *Cost Allocation Guideline (Distribution)*, 2008.

33 Ergon Energy, *Response to information request #014 - Ancillary network services,* 8 April 2019.

34 Ergon Energy, *Response to information request #050 - revised ancillary network services model,* 27 June 2019.

35 AER staff discussion with Ergon Energy staff, 21 August 2019.

36 Energex, *Response to information request #060 - ANS - significant price increases*, 21 August 2019. This was in response to Origin Energy's submission which highlighted proposed price rises compared to 2019–20 prices. See: Origin Energy, *Submission on Energex and Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, pp. 3-4.

prices.[37] Origin Energy specifically referred to connection management services (de-energisation/re-energisation) and auxiliary metering services.[38] We note that Ergon Energy previously charged some de-energisation and re-energisation services on a quotation basis, as well as all of its auxiliary metering services. This means there are limited comparisons to 2019–20.

Our analysis indicated that de-energisation and re-energisation fees for urban/short rural feeders have reduced in the revised June model compared to Ergon Energy's initial proposal, although there are still increases compared to 2019–20. The equivalent proposed fees for long rural/isolated feeders have reduced compared to 2019–20.

Given the continuing changes in Ergon Energy's modelling, we are not satisfied that we have sufficient information to assess the efficiency of Ergon Energy's proposed schedule of fees for its ancillary network services. Therefore, our draft decision is to reject all of Ergon Energy's proposed ancillary network service fees. Further, we will not be substituting our own prices until we have correct models and underlying assumptions to test the efficiency of the proposed prices.

We consider that it would be prudent for Ergon Energy to revise its underlying service assumptions and its model to ensure that efficient prices are proposed. We are also cognisant that stakeholders have not had an opportunity to consider Ergon Energy's revised models provided during our assessment process. We encourage Ergon Energy to include a comparison between its revised proposal and 2019–20 approved fees where possible, including explanations for significant changes. To improve transparency, we have published Ergon Energy's proposed pricing model provided to us in June 2019, and noted the modelling errors.

Proposed labour rates and service times

Notwithstanding our draft decision to reject Ergon Energy's proposed ancillary network service fees, we were still able to assess Ergon Energy's proposed labour rates and service times against our consultant's (Marsden Jacob) findings, which generally compared favourably.

In building up its fees for ancillary network services provided on a fee basis, Ergon Energy primarily used its technical service person labour category (both ordinary and overtime).[39] Marsden Jacob identified that in many cases, other distributors used the 'field worker' labour category to deliver the services it benchmarked and hence applied this labour category in undertaking its analysis.[40] As Ergon Energy's proposed total hourly labour rate for technical service person falls below Marsden Jacob's

---

37 Origin Energy, *Submission on Energex and Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, p. 3.

38 Origin Energy, *Submission on Energex and Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, pp. 3-4.

39 Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC.*

40 Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, p. 8.

recommended maximum for both technical specialist, and field worker, we consider that it is efficient and have made no changes.

Ergon Energy also used the para–professional labour rate in its cost build up for a small number of ancillary network services provided on a fee basis. We consider Ergon Energy's proposed labour rates are efficient where they are below our consultant's recommended maximums and substitute our consultants' recommended maximums where Ergon Energy's proposed labour rates are higher. This resulted in us rejecting Ergon Energy's proposed admin and para-professional, tech/PW/admin and system operator labour rates and substituting with our administration, tech /PW/admin labour category[41] and senior engineer labour rates respectively.

The substitution of our administration labour rate, based on our consultant's recommendations, results in a reduction of more than 50 per cent in Ergon Energy's labour rate for its para-professional labour category. Marsden Jacob previously considered a proposed para-legal labour category in its report on the NSW distributors, Evoenergy, TasNetworks and Power and Water Corporation.[42] Marsden Jacob determined that as the Hays labour rates for the relevant labour categories fell below the maximum administration rate, it was appropriate to apply the administration labour rate.[43] While we sought further information from Ergon Energy on when its para-professional labour rate would be applied, the response provided only indicated that this labour rate was included for completeness and transparency and that it might be applied in pricing some specific services provided on a quotation basis.[44] Ergon Energy may wish to make submissions in its revised proposal as to why we should consider its para-professional labour rate differently.

Our draft decision on all of Ergon Energy's proposed labour rates can be found in section 15.4.1.

Marsden Jacob also undertook benchmarking of the time taken for a number of common services between the distributors it considered and did not recommend making changes to any of Ergon Energy's proposed service times.[45] While Marsden Jacob undertook its benchmarking on Ergon Energy's models as at May 2019, we consider that it is still accurate as the June 2019 revisions mostly removed services or reduced labour times.

---

41 Ergon Energy's tech/PW/admin labour category is an average of the three underlying labour rates. As we have substituted our admin labour rate we have therefore taken a similar approach and recalculated this labour rate using our draft decision labour rates.

42 Marsden Jacob Associates, *Review of alternative control services - Advice to Australian Energy Regulator - PUBLIC version*, September 2018, p. 8.

43 Marsden Jacob Associates, *Review of alternative control services - Advice to Australian Energy Regulator - PUBLIC version*, September 2018, p. 8.

44 Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 10 May 2019.

45 Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, p. 14.

Finally, in reviewing the contractor rates used by Ergon Energy, we note that Marsden Jacob's report shows that Ergon Energy's proposed special meter read fee (which relies on contractors) benchmarks favourably to other DNSPs.[46]

We therefore accept Ergon Energy's proposed service times.

Shift of ancillary network services from a quotation basis to a fee basis (including fee permutations)

We questioned the necessity for the large volume of fees and related fee permutations Ergon Energy proposed. Specifically, we were concerned whether the prices Ergon Energy proposed were efficient for numerous ancillary network services that were previously charged on a quotation basis because it had forecast zero volumes. We were also concerned that the number of fee permutations may lead to issues with accurately charging customers and that it may be difficult for customers to understand all of the permutations.[47]

In response to our information request, Ergon Energy advised that it had undertaken an internal review before shifting most ancillary network services to a fee basis and that it could price them efficiently (including the different fee permutations), using a cost build up approach. Ergon Energy submitted that shifting ancillary network services to a fee basis would provide greater transparency and certainty for customers, as well as being administratively cheaper.[48] During our assessment process, Ergon Energy revised its ancillary network services' model several times, reducing its usage of anytime hours fee permutations (discussed below) and rationalising its service descriptions. This resulted in 329 service fees and fee permutations, compared to 451 in the original proposal.

Ergon Energy also corrected modelling errors, reduced some travel times and updated some of its overhead rates, leading to lower proposed prices. We consider that the proposed introduction of these fees and fee permutations provides Ergon Energy with a reasonable opportunity to recover its efficient costs, noting however, that our draft decision is to reject prices for all ancillary network services provided on a fee basis until Ergon Energy completes a review of its ancillary network services' proposal and underlying service assumptions as part of its revised proposal.

---

[46] Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, pp. 16-17.

[47] AER, *Information request #026 - Ancillary network services - further questions on fee permutations and modelling*, 3 May 2019.

[48] Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 20 May 2019.

Anytime hours

We raised concerns about Ergon Energy's proposed business hours; anytime; and after hour permutations for many services where the prices for anytime and after hours were identical. We therefore sought clarification from Ergon Energy who advised that:[49]

- The “Business hours” fee permutations is applied to services completed on the next *scheduled* business day (note: the service may not necessarily be completed on the same or next business day, as it will depend on when a particular planned service is scheduled to be conducted)
- The “Anytime” permutation is applied to certain services which are raised after the 1pm cut off time but are required to be prioritised and conducted on the same business day, and
- The “After hours” permutation is applied to certain services which are required to be completed outside business hours (i.e. before 8am or after 5pm).

Ergon Energy submitted that this pricing was cost reflective, capturing the additional administration costs involved in rescheduling jobs and providing services outside of the standard timeframe. Ergon Energy also submitted that this pricing recognised that the service may need to be completed after business hours for it to occur on the same day.[50]

Ergon Energy's revised model provided in late June 2019 which reduced its use of anytime hours fee permutations. Ergon Energy advised that it limited its use to re-energisations (for urban and short rural feeders) and supply abolishment services (for urban feeders only). Ergon Energy considered this simplified its service offering and improved alignment with jurisdictional regulatory requirements. It considered that anytime hours permutations should be retained for these particular services given they are high volume and customers may require these services to be prioritised.[51] Overall, the number of anytime hours fees reduced from 122 in Ergon Energy's original proposal to 26.

We are satisfied with Ergon Energy's reduced use of the anytime hours fee permutations. We consider that pricing the anytime hour fee permutation at the same rate as the after-hours permutation is reasonable in reflecting the efficient costs of prioritising these types of services. We also understand that customers are able to choose that a service be expedited in this fashion. Therefore, our draft decision is to accept that the anytime hours fee permutation be charged at the same rate as an after-hours fee.

Travel time to deliver services

Ergon Energy proposed applying two hours of travel time for services provided for long rural/isolated feeders and 20 minutes for services provided for urban/short rural feeders. The travel time for long rural/isolated feeders is consistent with our decision

49 Ergon Energy, *Response to information request #026 - further questions on fee permutations and modelling*, 20 May 2019.

50 Ergon Energy, *Response to information request #014 - Ancillary network services,* 8 April 2019.

51 Ergon Energy, *Response to information request #050 - revised ancillary network services model,* 27 June 2019.

for the current regulatory period, while the time proposed for urban/short rural feeders is less than the thirty minutes in our decision for the current regulatory period.[52]

We queried Ergon Energy about the appropriateness of the two hours of travel time as customer density, which was a factor in our previous decision, appeared to be increasing. Ergon Energy submitted that this increase was very slow, from 5.3 customer/km in 2015–16 to 5.4 customer/km in 2017–18. Ergon Energy also advised that it would continue to monitor customer density during the 2020–25 regulatory control period. Marsden Jacob also noted that this travel time did not seem unreasonable.[53] Given the marginal increase in customer density, we accept Ergon Energy's proposed travel time of two hours for long rural/isolated feeders. We consider it provides Ergon Energy with a reasonable opportunity to recover the efficient costs of serving rural and remote customers. We also accept 20 minutes travel time for urban/short rural feeders given it has declined since the current regulatory period, which reduces prices for customers.

Installation of Type 6 meters in Mount Isa-Cloncurry Network

Ergon Energy continues to be responsible for metering services, including meter installation and replacement, for its Mount Isa-Cloncurry network, which is not connected to the NEM. Ergon Energy's proposed prices (or upfront capital charges) for the installation of new and replacement meters are higher than its approved 2019–20 prices. Our analysis indicated that this increase was driven by a 111.98 per cent overhead rate applied to the direct cost of the meters (the materials cost).[54]

Ergon Energy confirmed that there is a modelling error and that non-network overheads should not be applied to materials.[55] We have noted this correction in the model published with this draft decision. This correction reduces the total overhead rate for materials to 41.60 per cent. Applying this correction generally reduces the proposed metering installation prices and while some are still increasing relative to 2019–20, others are declining.

This modelling correction has a marginal impact on all other ancillary network services that use materials. Ergon Energy confirmed that this modelling error will be corrected in its revised proposal.[56]

Our decision for the 2015–20 regulatory control period applied a different X Factor to metering installation services for the Mt Isa-Cloncurry network to reflect that a large

[52] AER, *Final decision - Ergon energy determination 2015–16 to 2019–20 - Attachment 16 - alternative control services,* October 2015, p. 16-15.

[53] Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator*, June 2019, p. 14.

[54] This is the product of non-network overheads (49.71 per cent), network overheads (23.16 per cent), and corporate costs, revenue on non-network capital costs, MTC & call centre costs (14.97 per cent).

[55] Email from Ergon Energy staff to AER staff, *EQ ancillary network services - overheads applied to materials*, 21 August 2019.

[56] Ergon Energy email to AER staff, *ACS Fee-based - Updated prices*, 23 August 2019.

component of the price was materials rather than labour. This meant that applying a straight labour escalator as the X Factor was not appropriate. Our previous decision applied a 60 per cent weighting based on the labour component relative to the materials component in the price of the service. Our analysis of the current proposal shows that this weighting changes depending on the type of meter, but more on the type of feeder, given the impact of travel time on the labour component. Therefore, our draft decision is to apply separate X Factors for the urban/short rural feeder and the long rural/isolated feeder types, based on an average of the relative proportion of labour to materials. We have not made a draft decision on these weightings because we have rejected Ergon Energy's proposed prices for all ancillary network services, however our *indicative* calculations show these weightings may be around:

- Urban/short rural - 60 per cent
- Long rural/isolated - 75 per cent.

Security lighting services

This is the first regulatory period that security lighting services will be treated as an alternative control service for Ergon Energy, having previously not been regulated.

While Ergon Energy initially proposed charging for security lighting services on a quotation basis, it clarified late in the draft decision process that only installation costs are to be charged on a quotation basis and that ongoing costs of maintenance, operation and replacement should be charged on a fee basis. Ergon Energy advised that this delineation in pricing was consistent with how it currently charged for the provision of security lighting services.[57]

Ergon Energy submitted that charging installation costs on a quotation basis was appropriate as they tend to be customer specific and are difficult to standardise. We have previously approved standardised installation costs for security lighting for the NSW distributors on a fee basis.[58] However, we accept that these installation costs may vary because of customer requirements and it is up to the customer as to whether they accept a quote or approach a competitor for an alternative solution. For the reasons above, we accept Ergon Energy’s proposal to charge for installation of security lights on a quotation basis.

In response to an information request, Ergon Energy proposed that the ongoing costs of security lighting services be charged on a fee basis, as the scope of the work can be pre-defined.[59] Ergon Energy submitted that this will minimise the impact on customers and provide price certainty. We accept Ergon Energy's proposal to charge ongoing security lighting services on a fee-basis to improve certainty for customers which goes

---

57 Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

58 For example, see AER, *Draft decision - Ausgrid distribution determination 2019-24 - Attachment 15 - Alternative control services,* pp. 15-19, 15-20.

59 Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

to tariffs being reasonably able to be understood by customers.[60] We also consider that it represents an appropriate trade-off between the administrative costs of having standardised prices rather than individually prepared quotes for each customer.[61]

However, we are unable to make a draft decision on a schedule of fees for security lighting until we receive Ergon Energy's revised proposal with its security lighting model to consider its proposed cost build up. We currently have limited information on how Ergon Energy charges for security lighting services and the underlying cost drivers, and as a previously unregulated service, we had no role in regulating the fees. Ergon Energy also advised that it is not appropriate to use its public lighting costs as they do not reflect security lighting costs.[62]

15.5 Public lighting

Public lighting services include the operation, maintenance, repair, replacement, alteration, relocation and provision of public lighting assets. Ergon Energy owns and operates over 140000 public lights servicing local government authorities (councils), Department of Transport and Main Roads and other Government entities.[63] This asset base includes 54000 public lighting assets 'gifted' to Ergon Energy by customers,[64] of which Ergon Energy now owns, maintains, and operates the lighting asset. There are an additional 13000 public lighting units that are owned and operated by customers,[65] of which Ergon Energy provides the electricity supply only.

15.5.1 Public lighting—Draft decision

Our draft decision is to:

- maintain public lighting as an alternative control service, consistent with our final F&A[66]
- apply our draft decision labour escalators and rate of return consistent with standard control services[67]
- accept Ergon Energy's proposed LED apportionment and rollout
- accept Ergon Energy's Asset Management Plan
- reject Ergon Energy's proposed capital expenditure
- reject Ergon Energy's proposed operating expenditure.

Our draft decision public lighting charges are listed in appendix B.

---

60 NER, cl. 6.18.5(h).

61 NER, cl. 6.18.5(f)(1).

62 Ergon Energy, *Response to information request #064 - ANS - Security Lighting,* 13 August 2019.

63 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 11.

64 Energy Queensland, *Asset Management Plan - Public Lighting*, October 2018, p. 5.

65 Energy Queensland, *Asset Management Plan - Public Lighting*, October 2018, p. 5.

66 AER, *Queensland 2020–25 - Final framework and approach for Energex and Ergon Energy*, July 2018, pp. 34-36.

67 Attachment 3 - Rate of Return; Attachment 6 - Operating Expenditure.

15.5.2 Public lighting—Reasons for draft decision

Form of control

We maintain our final F&A position to apply price caps to individual public lighting services as the form of control. This allows Ergon Energy to charge according to a schedule of prices, approved by the AER, in the first year of the regulatory control period, with these prices being escalated by CPI and an X-factor for subsequent years. The prices for the period have been smoothed, and the X-factor will be a nil value for the period. We consider this approach involves less complexity and provides stakeholders with consistency in the movement of charges from one regulatory year to the next (CPI).

The control mechanism formula is set out in attachment 13 of this draft decision.

LED rollout

We consider Ergon Energy's proposed approach to LED lighting to be satisfactory. This includes their rollout strategy, introduction of LED tariffs, and approach to pricing. However, we encourage Ergon Energy to provide stakeholders with further transparency around the LED transition. This includes the difference in cost build-ups for LED assets and operating expenditure to that of conventional lighting.

Ergon Energy proposed LED specific tariffs to reflect the cost efficiencies found in LED lighting compared to conventional lighting. To calculate these tariffs, Ergon Energy split its public lighting asset base according to current assets. Each asset base is then moved forward over the period with specific operating and capital expenditure forecasts, to reflect the costs for these different types of lighting. This allows for efficiencies to be found in operating expenditure relating to LED lighting, while recovering the depleting conventional lighting asset base from conventional lighting tariffs only. This creates an attractive price point for LED lighting that represents the lower cost of operating LED lighting, and incentivises customers to switch to LED.

In addition to the LED versions of current tariffs, Ergon Energy proposed a new NPL4 tariff to further incentivise the transition to LED lighting.[68] Where a customer funds the replacement of the luminaire and lamp to LED, they will move from the existing conventional NPL1 tariff to the NPL4 tariff. This proposal allows for customers to initiate a switch to LED without having to contribute the whole asset (NPL2) or wait for the end-of-life of the asset (NPL1). Customers who switch to this NPL4 tariff will be charged a tariff that is lower than the NPL1 tariff to reflect their contribution of the LED.

Ergon Energy provided prices for the NPL4 tariff in their proposal, however did not provide detail on how these were calculated. When requested, Ergon Energy provided the following calculation to explain its NPL4 tariffs:[69]

---

[68] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 19.

[69] Energy Queensland, *Response to Ergon Energy Information Request #057*, August 2019, pp. 3-4.

NPL4 tariff=(90% of NPL2 LED rate)+(70% of capital charge of NPL1 Conventional rate)

The 90 per cent of the NPL2 LED rate removes the 10 per cent capital component allocated for refurbishment. While we accept the 70 per cent rate of capital allocation, we do not accept the use of the conventional lighting capital component as the basis. After corrections to Ergon Energy's public lighting model for capital expenditure, and overhead allocation adjustments, the capital components of conventional lighting and LED lighting differ significantly enough to cause the NPL4 tariff to be higher than the NPL1 LED tariff. This causes a disincentive in using the NPL4 tariff, as the NPL1 LED tariff is cheaper, and does not require any customer contribution. For these reasons, our draft decision is to apply the LED capital as a basis for the NPL4 calculation:

NPL4 tariff=(90% of NPL2 LED rate)[70]+(70% of capital charge of NPL1 LED rate)

We consider that this approach properly incentivises customer contributions of LED lamps to assist in achieving Ergon Energy's LED rollout targets. This is also in line with the treatment of customers transitioning to LED on NPL1 and NPL2 tariffs, where they are charged for recovery of the LED asset base as opposed to the conventional lighting asset base after transition, while not incurring any exit fee.

Ergon Energy have set a target penetration for LED lighting of 47 per cent by the end of the 2020–25 period.[71] This reflects the strategies put forward in the asset management plan[72] that:

- All new and additional lights installed are to be LED
- 75 per cent[73] of mercury vapour lamps and luminaires are to be replaced with LED during the 2020–25 period[74]
- 20-25 per cent[75] of life-expired/failed conventional lights are to be replaced, gradually increasing to 30-40 per cent by 2025.[76]

The rollout of LED allows for both customer-led transition, as well as that led by Ergon Energy. Where a customer is transitioned to LED, there will be no exit fee charged as a total asset replacement does not occur, and the customer will retain their existing funding arrangement (i.e. NPL 1 or 2) on the lower LED rate.[77] We consider this rollout approach provides incentives for customers to change to LED lighting, while also

---

70 This 90% reflects the operating expenditure component of the NPL2 rate, after removing the 10% refurbishment component.

71 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25*, January 2019, p. 11.

72 Energy Queensland, *Asset Management Plan - Public Lighting*, October 2018, pp. 15-16.

73 Figure adjusted to reflect correct sum of years.

74 Year 1: 10%, year 2: 12.5%, year 3: 15%, year 4: 17.5%, year 5: 20%.

75 Modelled at 5% of portfolio.

76 Conversions limited to where only lamp and luminaire can be replaced with very limited bracket and/or pole replacements to minimise costs.

77 Energy Queensland, *Ergon TSS Explanatory Notes 2020–25*, June 2019, p. 50.

ensuring no burden is placed on customers when Ergon Energy initiates a transition to LEDs.

Under the Minamata Convention, production of mercury vapour lamps will be banned from import, export, and manufacture in most countries from 2020. The Australian Government is considering ratifying the convention, and being bound by its requirements.[78] Ergon Energy has initiated steps to replace its stock of in-use mercury vapour lamps in recognition of these future restrictions. Ergon Energy intends to replace these mercury vapour lamps with LED at the above rates, noting there is currently no requirement to remove mercury vapour lamps from use.[79]

Asset base allocation to NPL2

Ergon Energy proposed to smooth a 10 per cent refurbishment allocation of the public lighting asset base across both NPL1 and NPL2 tariffs.[80] This is to replace the previous approach where an asset replaced by Ergon Energy would trigger a re-assignment from NPL2 to NPL1 tariff.

We accept Ergon Energy's proposal to include this capex component in the NPL2 tariff. This removes the increased tariff charge of up to 199 per cent[81] where Ergon Energy is required to replace an asset, and allows for customers to retain the benefits of gifting assets past the life of the asset.

Operating expenditure

Ergon Energy used a base-step-trend method to forecast their operating expenditure for the 2020–25 period. We accept this approach, however we do not accept the level of overheads included in Ergon's forecasts.

In creating a base level for operating expenditure for both conventional and LED lighting, Ergon removed amounts related to one-off restructuring costs, as well as adjusting for significant changes in relation to the cost allocation method. These changes reduced overall operating expenditure by $3.04m ($2019–20) and reduced the base level operating expenditure by 19 per cent. We accept these adjustments to the base level operating expenditure.

Ergon Energy's proposal did not provide information regarding the overhead allocations for operating expenditure, however it provided further information when requested.[82] Ergon Energy advised that of the combined $13.38m base year operating expenditure, $4.8m represented overhead allocation. At the original base level operating expenditure of $16.24m (combined, before adjustments), this represents an

---

78 https://www.environment.gov.au/protection/publications/minamata-convention-mercury-and-lighting-fs.

79 Energy Queensland, *Asset Management Plan - Public Lighting*, October 2018, p. 16.

80 Energy Queensland, *Ergon Alternative Control Services 2020–25*, January 2019, p. 19.

81 Calculated on NPL2 tariff net of the capex component, compared to the total NPL1 charge (where 100% of PLAB is recovered on this tariff).

82 Energy Queensland, *Response to Ergon Information Request #057*, August 2019, p. 4.

overhead allocation of 41.96 per cent of direct costs. However after applying the above accepted adjustments, the overhead allocation represents 65.86 per cent of direct costs.

Our draft decision is to reject the proposed base level operating expenditure considering this level of overhead allocations. Our draft decision is to adjust the operating expenditure base level to 35 per cent as we find that the previous 41.96 per cent overhead allocation rate is too high. This is in line with our recent decision for TasNetworks.[83] This cap was based on the 25 per cent applied to Victorian distributors, with a 6 per cent allowance for expenditure which is not considered overheads in Victoria, and then a buffer to allow for the difficulty in benchmarking overheads. We invite Ergon Energy to provide a more detailed cost build-up approach to its operating expenditure as part of its revised proposal.

Ergon Energy also included adjustments to reflect the growth rate of assets. While natural logs have been used in the growth rate calculations for conventional lighting, the LED lighting growth rates used simple growth calculations. For consistency, we have updated the LED growth rates to the methodology used for conventional lighting.

Table 15.3 shows the movement in total operating expenditure between Ergon Energy's proposal and our draft decision.

Table 15.3 Operating Expenditure ($2019–20)

Operating Expenditure	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy Proposal - Conventional	12.71	11.67	10.31	8.68	6.75	50.12
Ergon Energy Proposal - LED	0.59	1.51	2.53	3.86	5.40	13.89
AER Draft Decision - Conventional	10.93	10.04	8.84	7.41	5.74	42.96
AER Draft Decision - LED	0.20	0.38	0.55	0.79	1.05	2.97

Capital expenditure

Ergon Energy provided capital expenditure models to support its forecasts for the 2020–25 period. We do not accept Ergon Energy's application of capitalised overheads on these forecasts, and have revised Ergon Energy's direct capital expenditure. We also recommend Ergon Energy consider a cost build-up approach to its capital expenditure to better forecast the expenditure on LED lighting.

Ergon Energy escalated base year capitalised overheads by the overall rate of change in its operating expenditure model. This rate of change predominantly represents the change in public lighting asset quantities (for each conventional and LED light type in its respective models). This does not reflect the direct capital expenditure forecast, and

[83] AER, Final Decision - *TasNetworks Distribution Determination 2019–24 - Attachment 15*, April 2019, pp. 14-15.

results in capitalised overheads that are up to 85 per cent of the total direct capital expenditure for that year.

Our draft decision is to reject this application of capitalised overheads, and instead, adjust this allocation to reflect direct capital expenditure. Specifically, we adjusted the model to reflect the same weightings in the base year of 2018–19, and applied this 27.92 per cent weighting to the forecasted direct capital expenditure for the regulatory control period.

Ergon Energy proposed direct capital expenditure for the period that does not reflect the forecasted unit growth rates of LED public lighting assets. The capital expenditure per forecasted unit growth in 2020–21 is $701.38, however it decreases to $574.30 in 2024–25. This is an 18 per cent decrease in costs over the period, and is across materials, labour, and contractor components of capital expenditure. While cost reductions may occur over the period due to decreasing material costs and economies of scale, Ergon Energy have not provided detail or analysis to propose this. We have therefore trended forward capital expenditure based on the calculated per unit cost from 2020–21. Table 15.4 shows the changes in capital expenditure resulting from our draft decision.

Table 15.4 Capital Expenditure ($2019–20)

Capital Expenditure (Total Gross)	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy Proposal - Conventional	5.60	6.05	5.74	5.23	4.90	27.52
Ergon Energy Proposal - LED	10.40	11.60	12.90	14.18	15.63	64.71
AER Draft Decision - Conventional	1.23	1.25	1.15	1.12	1.00	5.74
AER Draft Decision - LED	14.55	17.08	19.07	20.66	22.98	94.34

Note: Total gross capital expenditure is shown, which includes overheads and other asset classes, but does not reflect disposals and customer contributions.

Modelling

Ergon Energy's models supporting its proposal contained a number of errors, including:

- NPL4 minor tariffs
- Historical capital expenditure and customer contribution values
- Differing growth rate methodologies for conventional lighting and LED
- Values hard-coded over formulae in the AER's PTRM
- Omission of WACC for years 2 to 5 in pricing model

- Customer contributions' real values used instead of nominal values in pricing model[84]
- NPL1 tariff calculations - incorrect customer base.[85]

Ergon Energy corrected these issues in updated models. This included the use of the latest PTRM released in April 2019. Further to these corrections, we have adjusted the models to reflect the AER's updated return-on-debt, labour escalators and other related inputs.

Asset Management Plan

Our draft decision is to accept Ergon Energy's public lighting asset management plan.[86] We consider that it sufficiently addresses regulatory compliance, asset management, LED rollout and minimum service levels. We consider that the preventative maintenance activities of Ergon Energy are appropriate in relation to its inspection and bulk lamp replacement programs. To improve transparency, we recommend that Ergon Energy includes more detailed information around the failure rates of lighting assets.

Submissions

We consider Ergon Energy's public lighting proposal, supported by its asset management plan and public lighting strategy documents, provides an acceptable picture of its treatment of public lighting assets and LED rollout. However, we consider that the proposal lacks transparency and discussion around key components of public lighting expenditure, as well as including errors which could cause confusion and contention amongst stakeholders.

The AER's Consumer Challenge Panel (CCP sub-panel 14) commented that Ergon Energy engaged with councils, and that the proposal reasonably reflects stakeholder needs.[87] This was the only submission received for public lighting for Ergon Energy. We encourage submissions on our draft decision and Ergon Energy's revised proposal from customers and other stakeholders.

Price movements

As LED rollout programs occur, it is important to track price movements between regulatory control periods, as well as LED price incentives. The importance of this is heightened by the Energex-Ergon Energy merger, and the alignment of processes and tariff strategies between the two service providers. Price movements from 2019–20 to 2020–21 are shown in Table 15.5.

---

[84] These values had no impact on the pricing model for which they were included, and have subsequently been removed.

[85] This issue caused an omission of $4.7m of revenue each year.

[86] Energy Queensland, *Asset Management Plan - Public Lighting*, October 2018.

[87] Consumer Challenge Panel 14, *Submission on Ergon's Regulatory Proposal 2020–25*, May 2019, p. 21.

Table 15.5 Price Movements ($ nominal $/day)

				2019–20	2020–21	% change	LED incentive[88]
Ergon Proposal	Conventional	NPL1	Major	1.310	0.780	-40.5%	
			Minor	0.780	0.479	-38.6%	
		NPL2	Major	0.529	0.449	-15.2%	
			Minor	0.346	0.295	-14.9%	
	LED	NPL1	Major	1.310	0.815	-37.7%	4.6%
			Minor	0.780	0.492	-36.9%	2.8%
		NPL2	Major	0.529	0.449	-24.5%	-11.0%
			Minor	0.346	0.261	-24.7%	-11.5%
		NPL4	Major		0.710		-12.9%
			Minor		0.440		-10.6%
AER Draft Decision	Conventional	NPL1	Major	1.310	0.901	-31.2%	
			Minor	0.780	0.535	-31.4%	
		NPL2	Major	0.529	0.347	-34.3%	
			Minor	0.346	0.227	-34.4%	
	LED	NPL1	Major	1.310	0.326	-75.1%	-63.9%
			Minor	0.780	0.202	-74.1%	-62.2%
		NPL2	Major	0.529	0.201	-62.0%	-42.1%
			Minor	0.346	0.133	-61.6%	-41.5%
		NPL4	Major		0.268		-17.7%
			Minor		0.168		-16.9%

Note: Ergon Energy advised of errors in its pricing model, causing issues in the calculations of some prices. This can be seen in the disincentive for NPL4 tariffs, and the increased incentives for LED incentives. Ergon Energy advised that it will fix the issue for the model provided in its revised proposal.

15.6 Metering services

Metering services include the maintenance, reading, data services, and the recovery of capital costs related to type 6 meters installed prior to 1 December 2017. Metering assets are used to measure electrical energy flows at a point in the network to record

[88] LED incentive is the difference between the respective conventional and LED rates. For NPL4, the incentive is in relation to the NPL1 LED lighting tariff, as it represents an NPL1 customer contributing an LED luminaire to an Ergon owned asset.

consumption for the purposes of billing. Ergon Energy forecast a metering population of nearly 900000 meters at the beginning of the 2020–25 regulatory control period.[89]

Since introduction of the Power of Choice reforms on 1 December 2017, Ergon Energy is no longer permitted to provide or install type 6 meters. Customers are now able to source new meters from the contestable market. New minimum standards for meters mean that only advanced or 'smart' meters (generally a type 4 meter for residential customers) with remote communications capability may now be installed.

Ergon Energy noted that as the Mount Isa-Cloncurry network in Ergon Energy's distribution area is not part of the National Electricity Market, it is therefore not covered by the Power of Choice reforms.[90] Ergon Energy will continue to be the monopoly provider of metering services in this area, as noted in our final F&A.[91]

We are responsible for setting price caps relating to meter reading, maintenance, and data services. These charges exclude the provision/installation of type 6 meters, so do not include up front capital charges for new meters (other than those in the Mount Isa-Cloncurry network).

15.6.1 Metering services—Draft decision

Our draft decision is to:

- apply our draft decision labour escalators and rate of return consistent with standard control services[92]
- accept Ergon Energy's building block approach and metering asset base
- reject Ergon Energy's proposed capital expenditure
- reject Ergon Energy's proposed operating expenditure.

Our draft decision metering charges are listed in appendix C.

15.6.2 Metering services—Reasons for draft decision

Form of control

We maintain our final F&A position to apply price caps to individual metering services as the form of control. This allows Ergon Energy to charge according to a schedule of prices, approved by the AER, in the first year of the regulatory control period, with these prices being escalated by CPI and an X-factor for subsequent years. The prices for the 2020–25 regulatory control period have been smoothed, and the X-factor will be a nil value for the period.

[89] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 7.

[90] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 4.

[91] AER *Queensland 2020–25 - Final framework and approach for Energex and Ergon Energy*, July 2018, pp. 30-31.

[92] Attachment 3 - Rate of Return; Attachment 6 - Operating Expenditure.

We consider this approach involves less complexity and provides stakeholders with consistency in the movement of charges from one regulatory year to the next (CPI). This control mechanism formula is set out in Attachment 13 of this draft decision.

Ergon Energy's type 7 metering services are an unmetered connection and are classified as standard control services, and therefore not dealt with under metering services.[93]

Structure of metering charges

Our draft decision is to approve Ergon Energy's proposed metering charging structure:[94]

- This is an annual charge comprising two components:
    - capital—metering asset base (MAB) recovery and tax allowance
    - non-capital—operating expenditure.

This structure is consistent with the approved structure in the current regulatory period, with the exception that an upfront charge for meter installation no longer applies as Ergon Energy is no longer responsible for providing or installing meters (other than those in the Mount Isa-Cloncurry network).

This structure is both reflective of the actual costs involved in the provision of metering services and, due to being consistent with current charges, easy to understand. This structure also allows Ergon Energy to apply non-capital costs only to those customers who should be charged for them. As customers adopt smart meters, services and service costs related to the meter are borne by the retailer, and are therefore charged by the retailer. Therefore Ergon Energy's metering costs should be recovered in a manner that allows for customers who have 'churned' to no longer be charged for Ergon Energy's forgone non-capital expenditure. However, Ergon Energy is still allowed to recover the capital costs of the replaced asset where appropriate.

Capital expenditure

Ergon Energy proposed direct capital expenditure of $0.38m in its regulatory proposal for the 2020–25 regulatory control period.[95] This capital expenditure relates solely to the Mt Isa-Cloncurry network, where Ergon Energy is the monopoly provider of metering services. In addition to this, Ergon Energy proposed $16.71m of non-network capital expenditure (not directly related to its metering assets) for the 2020–25 regulatory control period.[96]

---

[93] AER *Queensland 2020–25 - Final framework and approach for Energex and Ergon Energy*, July 2018, p. 31.

[94] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 10.

[95] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 6.

[96] Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 6.

Our draft decision is to accept the direct capital expenditure component, reject the proposed non-network capital expenditure amount, and instead apply no non-network capital expenditure for the 2020–25 regulatory control period. We consider that there should be no or minimal apportionment of non-network capital expenditure applied to metering services while there is such a limited amount of direct capital expenditure.[97] We consider this will shorten the timeframe required to deplete the remaining metering asset base, and reduce the likelihood of any price spikes in later years.

Operating expenditure

Ergon Energy used a base-step-trend method to forecast its operating expenditure for the 2020–25 regulatory control period.[98] We accept this approach, however we do not accept the base level operating expenditure because of the level of overheads included in Ergon Energy's forecasts.

In creating a base level for operating expenditure for metering, Ergon Energy removed amounts related to one-off restructuring costs, as well as adjusting for changes in relation to the cost allocation method. These changes reduced overall operating expenditure by $3.57m and reduced the base level operating expenditure by 10.26 per cent. We accept these adjustments to the base level operating expenditure.

Ergon Energy's proposal did not provide information regarding the overhead allocations for operating expenditure, however it provided further information upon request.[99] Ergon Energy advised that of the $31.59m base year operating expenditure, $10.6m represented overhead allocation. At the original base level operating expenditure of $34.77m (before adjustments), this represents an overhead allocation of 43.86 per cent of direct costs. However, after applying the above accepted adjustments, the overhead allocation represents 50.51 per cent of direct costs.

For the above reasons, our draft decision is to reject the proposed base level operating expenditure considering the level of overhead. Our draft decision is to adjust the operating expenditure base level to 35 per cent overhead allocation as we consider that the previous 43.86 per cent overhead allocation rate is too high. This is in line with our recent decision for public lighting expenditure for TasNetworks,[100] and also with our draft decisions for public lighting and metering expenditure for Energex. Specifically, for this draft decision we calculated the difference in the overhead amounts, escalated to 2019–20 dollars, and applied as an adjustment in the model.

Ergon Energy also included adjustments to reflect the metering ‘churn’ as customers have new type 1-4 meters installed. Ergon Energy provided a breakdown of the

---

97 We note that the direct capital expenditure is made up of customer contributions, and will therefore not increase the metering asset base - resulting in no gross capital expenditure.

98 Energy Queensland, *Ergon Energy Alternative Control Services 2020–25,* January 2019, p. 7.

99 Energy Queensland, *Response to Ergon Energy Information Request #056*, August 2019, p. 2.

100 AER, Final Decision - *TasNetworks Distribution Determination 2019–24 - Attachment 15*, April 2019, pp. 14-15.

calculation of this metering churn upon request,[101] which showed a churn rate different to the 8 per cent used in its models. We have updated the churn rate to 7.86 per cent in Ergon Energy models, to reflect the calculations provided.

Table 15.6 shows the movement in total operating expenditure between Ergon Energy's proposal and our draft decision.

Table 15.6 Operating Expenditure ($2019–20)

Operating Expenditure	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy Proposal	28.85	26.45	24.35	22.47	20.79	122.90
AER Draft Decision	25.76	23.64	21.74	20.04	18.51	109.69

Price movements

It is important to track price movements between regulatory control periods, to ensure there are no unnecessary price increases, especially in light of the depleting metering asset base. The importance of this is heightened by the Energex-Ergon Energy merger, and the alignment of processes and tariff strategies between the two service providers. Price movements from 2019–20 to 2020–21 are shown in Table 15.7. While these price movements show changes between the capital and non-capital components, the overall movement for each tariff is less than forecast inflation, and therefore is decreasing in the first year of the 2020–25 regulatory control period.

Table 15.7 Price Movements ($ nominal cents/day)

			2019–20	2020–21	% change
Ergon Energy Proposal	Primary	Capital	3.925	3.217	-18.04%
		Non-capital	10.716	10.698	-0.16%
	Load Control	Capital	1.443	1.183	-18.03%
		Non-capital	3.940	3.934	-0.16%
	Solar PV	Capital	0.976	0.800	-18.04%
		Non-capital	2.665	2.660	-0.17%
AER Draft Decision	Primary	Capital	3.925	3.734	-4.87%
		Non-capital	10.716	9.489	-11.45%
	Load Control	Capital	1.443	1.356	-6.00%
		Non-capital	3.940	3.478	-11.72%
	Solar PV	Capital	0.976	1.022	4.67%
		Non-capital	2.665	2.321	-12.90%

101 Energy Queensland, *Response to Energex Information Request #052*, August 2019, p. 1.

A Ancillary network services prices

Table 15.8 Non-exhaustive list of ancillary network services provided on a quotation basis, draft decision

Description of service
Connection services
Connection application and management services
Enhanced connection
Network ancillary services
Network safety services
Customer, retailer or third party requested appointments
Removal/rearrangement of network assets
Sale of approved materials or equipment
Security lights
Non-standard network data requests
Metering Services
Auxiliary metering services
Provision of services for approved unmetered supplies
Public lighting services
Auxiliary public lighting services

Source: Adapted from Ergon Energy, *Tariff structure statement 2020 - 2025*, June 2019, pp. 38-41.

Table 15.9 Ancillary network services hourly labour rates for 2020–21, draft decision ($2020–21)

Ergon Energy labour category	AER labour category[2]	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads) - Ordinary time	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads) - Over time
Admin Employee	Admin	$77.00	$134.75
Professional	Project Manager	$205.72	$263.08

Ergon Energy labour category	AER labour category[2]	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads) - Ordinary time	AER draft decision - maximum total hourly rate (base plus on-costs plus overheads) - Over time
Managerial			
Power Worker	Field Worker	$142.64	$186.93
Technical Service Person	Technical Specialist	$174.16	$228.94
Electrical System Designer	Engineer	$161.58	$207.60
Supervisor	Project Manager	$192.84	$250.50
Para-Professional	Admin	$77.00	$134.75
Apprentice	Field Worker	$106.52	$136.86
System Operator	Senior Engineer	$225.08	$340.87
Tech/PW[1]	Tech/PW[1]	$158.40	$207.94
Tech/PW/Admin[1]	Tech/PW/Admin[1]	$131.27	$183.54

Source: Energex and Ergon Energy, *EGX ERG 15.009 Fee-based and quoted services model - ACS JUNE19 PUBLIC*, AER calculations based on Marsden Jacob Associates, *Review of alternative control services: SA Power Networks, Ergon Energy and Energex – Advice to Australian Energy Regulator - Addendum*, August 2019.

Note: 1: The labour rates for these labour categories are an average of the labour rates for the underlying labour categories. While the AER does not have a specific matching labour category we have taken a similar approach and applied the average of our draft decision labour rates for the relevant categories.

2: Based on Marsden Jacob report. These labour categories are for comparison purposes only.

Table 15.10 AER draft decision on X-factors for each year of the 2020–25 regulatory control period for ancillary network services (per cent)

	2021–22	2022–23	2023–24	2024-25
X-factor	-0.6285%	-0.5244%	-0.5770%	-0.4984%

Source: AER analysis.

Note: We do not apply an X-factor for 2020–21 because we set the 2020–21 ancillary network service prices in this determination.

To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X-factors. Therefore, they are negative.

B Public lighting prices

Table 15.11 2020–21 prices ($ nominal)

			$/day	$/year
Conventional	NPL1	Major	0.901	329.00
		Minor	0.535	195.32
	NPL2	Major	0.347	126.79
		Minor	0.227	82.99
LED	NPL1	Major	0.326	118.91
		Minor	0.202	73.88
	NPL2	Major	0.201	73.37
		Minor	0.133	48.58
	NPL4	Major	0.268	97.91
		Minor	0.168	61.43

Note: The X-factors for public lighting services for the remaining years of the period are 0 per cent, and prices are only escalated for inflation.

C Metering Prices

Table 15.12 2020–21 prices ($ nominal)

		cents/day	$/year
Primary	Capital	3.734	13.63
	Non-capital	9.489	34.64
Load Control	Capital	1.356	4.95
	Non-capital	3.478	12.70
Solar PV	Capital	1.022	3.73
	Non-capital	2.321	8.47

Note: The X-factors for metering services for the remaining years of the period are 0 per cent, and prices are only escalated for inflation.