REGULATED ELECTRICITY FEED-IN TARIFF RATE TO APPLY FROM 1 JULY 2022

PRICING INVESTIGATION DRAFT REPORT

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OVERVIEW

The Tasmanian Economic Regulator (the Regulator) is conducting an investigation to determine a method for calculating the minimum feed-in tariff rates for feed-in tariff customers, to apply for the next three-year regulatory period from 1 July 2022 to 30 June 2025.

This paper sets out the Regulator's intended methodology for determining the minimum feed-in tariff rates to apply during this period, as well as a provisional feed-in tariff rate for 2022-23 based on the application of this methodology.

What is a feed-in tariff?

A feed-in tariff is the price at which at which consumers are credited when they export excess electricity generation into the electricity network from their small-scale solar, wind, or hydro fuelled generation systems, known as a distributed energy resources (DER). These consumers are not in a position to negotiate a feed-in tariff rate with electricity retailers and there is no practical alternative to these exports being purchased by retailers.

Electricity retailers operating in Tasmania are required to pay, as a minimum, regulated feed-in tariffs to customers for electricity supplied to the distribution network by qualifying electricity generating systems. There is no obstacle to retailers offering a feed-in tariff rate above the minimum rate; this has occurred in Tasmania in recent years.

A qualifying system as one that generates electricity from either solar, wind or water, which has a maximum generating capacity of 10 kW, and is connected to the distribution system.[1]

The feed-in tariff in Tasmania is a single-rate tariff that does not vary across the day. The rate is expressed in cents per kilowatt hour (c/kWh).

Setting the regulated feed-in tariff rate

Under the *Electricity Supply Industry Act 1995* (ESI Act), the Regulator must determine the minimum feed-in tariff rate that retailers are obliged to offer customers with qualifying generation systems on mainland Tasmania.[2]

In determining the feed-in tariff rate, the Regulator uses the established 'avoided cost' methodology in which the tariff is set based on the 'building blocks' of avoided costs or net financial benefit to retailers from on-selling electricity exported to the network by feed-in tariff customers. These avoided costs are:

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1 Section 44B of the *Electricity Supply Industry Act 1995*. Customers with systems with generating capacity greater than 10 kW can negotiate a market feed-in tariff rate with their retailer. See Appendix A for detailed eligibility criteria.

2 Electricity on the Bass Strait Islands is provided by Hydro Tasmania. For renewable energy generating system with a total capacity of less than 7.46kWh, the *Bass Strait Islands solar feed-in tariff agreement* applies.

- wholesale electricity costs - the price retailers avoid paying for wholesale electricity purchases when a small-scale renewable generator exports electricity to the grid;
- transmission and distribution losses - energy is lost transmitting electricity through the transmission and distribution networks from the generator to the customer. These losses are much lower when a small generator that is embedded in the distribution network exports to the grid; and
- market fees and ancillary service charges - National Electricity Market (NEM) management fees and ancillary services charges are paid by retailers to the Australian Energy Market Operator[3] on a per MWh basis for electricity purchases and sales through the wholesale market.

Under the avoided cost methodology, these cost 'blocks' are added together to produce a feed-in tariff rate that reflects the market value of the electricity to retailers.

This methodology aims to ensure that customers with solar PV systems receive a return for the electricity they export to the grid which reflects the market value of that energy to retailers, while ensuring that the feed-in tariff rate does not have the effect that any customer would effectively be cross-subsidising any other customer.[4]

Each year, the Regulator makes its determination of the regulated feed-in tariff rate to apply from 1 July. These annual determinations account for any changes in the various cost components of the feed-in tariff rate that have occurred since the previous determination. The feed-in tariff rate changes each year, mostly because of changes in wholesale electricity prices, which makes up around 90 per cent of the costs included in the minimum feed-in tariff.

Appendix A sets out the legislative framework for setting the minimum feed-in tariff, including those matters the Regulator must consider in making its determination.

Matters outside the scope of the Regulator's decision

There are a number of matters relating to Government policy or arrangements governed by the National Electricity Rules that may affect small-scale distributed generation systems. These include:

- any Australian or Tasmanian Government policies to support distributed energy generation;
- mechanisms to support distributed generation;
- network support payments;
- the promotion of households battery storage and electric vehicles;
- the promotion of smart meters;
- network voltage regulation; and
- non-monetary benefits of solar energy.

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3 The Australian Energy Market Operator (AEMO) manages the electricity and gas systems and markets across Australia. This includes the National Energy Market (NEM) which connects the power systems in Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

4 Section 44H(f) of the *Electricity Supply Industry Act 1995*.

The Regulator has determined that these matters are outside the scope of this investigation. This is because if these matters were included, and influenced the regulated feed-in-tariff rate, it would result in:

- the regulated feed-in-tariff rate imposing an unreasonable cost on retailers and windfall gain to feed-in tariff customers if the rate is above the avoided costs of retailers; or
- the regulated feed-in-tariff rate at too low a rate for feed-in tariff customers and a windfall gain to retailers if the rate is below the avoided costs of retailers.

Draft decisions

The Regulator has chosen to retain the avoided -cost method of determining the feed-in tariff rate, as used for the 2019 Determination. This is consistent with the Regulator's objectives under the *Economic Regulator Act 2009* and the Electricity Supply Industry Act which include:

(a) promoting efficiency and competition in the electricity supply industry; and

(b) protecting the interests of consumers of electricity.

In setting the regulated feed-in tariff, the principles to be taken into account are set out in section 44H of the ESI Act. These principles are provided at Appendix A.

Chapter 1 provides further detail on the methodology used in setting the feed-in tariff rate.

Calculation of the rate

The feed-in tariff rate is the sum of the avoided cost 'blocks' that have been determined as appropriate for inclusion in the cost build up. The steps to calculate the rate are as follows:

Forecast the wholesale electricity price

To estimate the price a retailer would pay for electricity purchased in the national electricity market (NEM) instead of from feed-in tariff customers, the Regulator starts with the price that retailers pay other generators for the energy they produce.

The Regulator has determined that the relevant wholesale electricity cost is the regulated wholesale electricity price (WEP), calculated using a regulated wholesale contract approach for a financial year. This is the same approach used to determine the wholesale electricity cost component of standing offer retail prices.

Add the value of NEM fees and charges that retailers avoid paying

Retailers pay market fees and ancillary service charges to the Australian Energy Market Operator (AEMO) that are based on the amount of electricity that is purchased from the wholesale market (NEM). Retailers can avoid these charges to the extent that they source electricity from distributed energy generators. The Regulator includes these fees and charges in the calculation of avoided costs as they reflect the value of NEM fees and charges a retailer avoids by purchasing electricity from a small scale renewable generator.

In 2021-22, AEMO introduced two new fees to recover the costs of the five-minute and global settlement rule changes and related upgrades to legacy IT systems for the NEM, and also the

cost of its distributed energy resource (DER) integration program.[5] The Regulator has included these costs in its calculation of the AEMO component of the feed-in tariff in its draft decision.

Increase the value by an avoided loss factor

When electricity is purchased from distributed generation systems, it reduces the total amount of electricity required to be purchased by retailers as they can avoid the cost of electricity they purchase but cannot sell to customers due to losses associated with transporting electricity over the transmission and distribution networks. These losses are typically between five and six per cent.

To account for this cost saving to retailers, it is appropriate that the wholesale electricity price is adjusted upwards by applying a 'loss factor' to the avoided cost of purchasing some electricity in the wholesale market.

Using Aurora Energy's estimates of distribution and marginal loss factors applying to small customers, a customer-weighted line loss factor is applied to the wholesale electricity price, and the distribution loss factor is applied to NEM market fees.

Components of the minimum feed-in tariff

The final value of the feed-in tariff will be determined by the Regulator in mid-June 2022 when the value of all the cost components have been finalised. A provisional estimate of the draft regulated feed-in-tariff rate for 2022-23 under the intended methodology is presented below. This estimate is based on an estimate of the WEP as at 17 January 2022 and 2021-22 values for losses and AEMO fees and charges. It is expected that the values of all components will be different by late May 2022, though it is unlikely that the difference for any component will be large.

Provisional estimate of the 2022-23 feed-in tariff (c/kWh)

Component	c/kWh
Wholesale electricity price	6.184
Avoided market fees and ancillary service charges	0.120
Value of avoided transmission and distribution losses	0.361
Provisional feed-in tariff rate (rounded)	**6.665**

The provisional feed-in tariff rate is around the same as the rate for 2021-22 (6.501 cents/kWh).

How to give feedback

The Regulator invites written comment on this document and encourages all interested parties to provide submissions addressing the matters discussed.

[5] AEMO, *2021-22 AEMO Consolidated Budget and fees*, October 2021.

It is the Regulator's policy to publish all submissions on the Office of the Tasmanian Economic Regulator's (OTTER) website unless the author of the submission requests confidentiality in relation to the submission (or any part of the submission). Those parts of a submission that are requested to be confidential should be submitted as an attachment to that part suitable for publication.

The Regulator will not publish submissions which contain material that it believes is, or could be, derogatory or defamatory.

Submissions should be received by close of business on **15 March 2022**.

To facilitate the publication of submissions on OTTER's website, submissions by email are preferred. Submissions and enquiries may be made to:

office@economicregulator.tas.gov.au

or to

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A copy of this Draft Report may also be found on OTTER's website: www.economicregulator.tas.gov.au.

1 SETTING THE FEED-IN TARIFF RATE

1.1 Distributed energy and the retail energy market

A distributed energy resource (DER) is a small-scale unit of power generation or storage that is connected to the power grid at the distribution level. Devices that enable distributed energy resources, such as rooftop solar systems, are often referred to as being 'behind the meter' because the electricity is generated or managed 'behind' the electricity meter in the home or business.

More than 13 per cent of households and small business premises on mainland Tasmania have installed small-scale electricity generating units such as a solar photovoltaic (PV) system, or solar panels.[6] Eligible customers receive two main benefits from these systems:

- bill savings: using electricity generated onsite to offset electricity that would otherwise be purchased from the customer's retailer; and
- export tariff (feed-in tariff): payment for every kilowatt hour of electricity exported to the distribution network.

1.2 Methods used to set the feed-in tariff rate

In making its decision in respect to the regulated feed-in tariff for mainland Tasmania, the Regulator has considered the approaches, methodologies, findings or recommendations taken or made in other jurisdictions.

Regulators in Australia have similar approaches to calculate the value of energy exported to the grid by small customers. Typically, regulators use the avoided cost method, which values exports as the net financial benefit to retailers. However, each regulator has a slightly different approach to calculating the components of the avoided cost, and some have additional matters to take into account.

Not all state and territory regulators set a minimum feed-in tariff rate. Some determine benchmark ranges that retailers must comply with, while others are less prescriptive and retailers are free to set their own feed-in tariffs. Appendix B sets out the recent decisions made by regulators in other jurisdictions.

1.2.1 Avoided cost method

Under this approach, regulators determine the costs retailers avoid when they use exports from customers rather than purchasing electricity from the NEM. The value of these cost components are added together to determine the feed-in tariff rate. These cost components generally include:

6 TasNetworks' *Annual Electricity Distribution Network Performance Report 2020-21 (FiT customers),* and AER.

- forgone wholesale electricity purchases – since retailers are selling some electricity purchased from owners of distributed generation instead of from large scale generators;
- savings in NEM market fees and ancillary charges – because these are levied on retailers' net purchases through the NEM, as set and charged by the Australian Energy Market Operator (AEMO); and
- electricity network energy losses - these tend to be lower as electricity exported from distributed generation reduces the need to transport electricity over long distances.

Regulators use a range of different methods to forecast or estimate the individual cost components of the feed-in tariff rate. In some jurisdictions, other factors are included in the calculation of the feed-in tariff, and these are discussed below.

1.3 Factors considered when setting the rate

In the Regulator's previous feed-in tariff rate determinations, the feed-in tariff rate for standard feed-in tariff customers has been set by reference to the net financial benefit that retailers receive from on-selling electricity exported to the network by feed-in tariff customers.

This approach, defined here as the 'net financial benefit to retailers' methodology, best reflects the principles underlying the feed-in tariff rate determination, as set out under section 44H of the ESI Act.

The Regulator sets the minimum feed-in tariff rate for customers with eligible generation systems at the same price as what it would cost retailers to buy electricity from large generators. This means the feed-in tariff will vary with changes in the wholesale electricity price. The feed-in tariff rate is calculated each year to allow for changes in the wholesale electricity price and other cost components.

This approach is used by regulators in other Australian jurisdictions and remains appropriate in the Tasmanian context.

1.3.1 Wholesale energy costs

Feed-in tariff customers are electricity generators and, like larger-scale generators, are entitled to receive compensation for the electricity they export to the grid. Both small-and large-scale generators receive the same price, the wholesale price, for any exports they make to the grid. As such, the electricity wholesale price is the primary determinant of the feed-in tariff rate.

The actual value of energy generated by small-scale distributed energy systems is considerably less than the retail price that retailers charge for electricity. This is because retailers only avoid a relatively small portion of their normal business costs when they source energy from PV customers as opposed to large-scale generators. Of these avoided costs, the cost of purchasing electricity through the NEM (the wholesale cost), is the most significant.

Under the 'net financial benefit to retailers' methodology, the wholesale electricity price used in the calculation of the feed-in tariff rate should reflect the prices any retailer in Tasmania can expect to pay for wholesale electricity purchases from large-scale generators.

In previous investigations, the Regulator has used the regulated wholesale electricity price (WEP) as approved under section 43G of the ESI Act, to calculate the wholesale energy cost

component of the feed-in tariff rate. This is the same price used by the Regulator in determining the wholesale electricity cost component of Aurora Energy's (Tasmania's regulated offer retailer) standing offer retail prices.

The ESI Act and the Regulator's *Standing Offer Price Approval Guideline* set out the arrangements for calculating the WEP, which is estimated in late May each year for the following financial year.

The Regulator uses a regulated wholesale contract approach to calculate the wholesale electricity price (WEP) for a financial year, as set out in the *Standing Offer Price Approval Guideline.* This is currently calculated using the average of weekly load following swap prices (regulated contract prices calculated under the Tasmanian wholesale contract regulatory framework) weighted by the absolute minimum capacity offer volume for the eight quarters prior to the financial year in which the price will apply.

The Regulator has applied this method in its 2013, 2016, and 2019 feed-in tariff rate determinations and considers it is appropriate for determining a cost-reflective wholesale energy cost for the regulated feed-in tariff.

The benefits of using a regulated market approach include transparency, and that the decision matches the wholesale electricity cost built into regulated standing offer prices.

Alternative approaches to calculating an appropriate wholesale cost component have been suggested during previous investigations, such as an export-weighted wholesale price. However, any methodology that results in a wholesale price higher than the regulated price may not be consistent with Section 44H(f) of the ESI Act, which stipulates that any feed-in tariff rate specified in the determination should not have the effect that any customer would effectively cross-subsidise any other customer. If a wholesale price above the WEP were used in determining the feed-in tariff rate, in the case of for Aurora Energy as the regulated offer retailer, it would seek to recoup the net cost from other charges to its customers on standing offer prices, such as the daily fixed charge. The overall result would be that feed-in tariff customers with relatively high exports would benefit at the expense of other customers.

In addition, if a wholesale price above the WEP were used in determining the feed-in tariff rate, this may discourage retailers from entering the Tasmanian market, or offering supply to customers with small-scale distributed energy systems, as they may be making losses.

The Regulator proposes to maintain its previous approach of using the regulated wholesale electricity price, which is the price determined by the Regulator under section 40AB(3) of the ESI Act.[7]

1.3.2 NEM management fees and ancillary service charges

To fund the operation of the National Electricity Market (NEM), retailers and other market participants pay NEM management fees and ancillary service charges to the Australian Energy Market Operator (AEMO). Some of these fees and charges are variable, based on the amount of wholesale electricity they purchase through the NEM.

[7] Tasmanian Economic Regulator, *Standing Offer Price Approval Guideline*, December 2020.

As the amount of wholesale electricity purchased is reduced by exports from distributed generation, some of a retailer's liability for these fees is also reduced as they are calculated on a lower volume of wholesale electricity purchased.

NEM management fees and ancillary service charges are incorporated into feed-in tariffs in other NEM jurisdictions and the continued inclusion of these fees in calculating the feed-in tariff rate has been supported during all previous consultations. It is therefore appropriate that these fees be included in the feed-in tariff. It reflects the value of ancillary service charges and market fees a retailer avoids by purchasing electricity from a small scale renewable generator.

The Regulator intends to continue to include the proportion of NEM management fees and ancillary service charges that vary with the amount of wholesale electricity purchased, payable by retailers, in the determination of the feed-in tariff rate.

1.3.2.1 Market fees

Up to 30 June 2020, AEMO recovered its National Transmission Planner (NTP) costs from retailers via a market fee. From 1 July 2020, NTP fees have been recovered from transmission network providers (TNSP), and therefore have been excluded from the Regulator's calculation of avoided wholesale electricity costs since that time.

The NEM fees levied by AEMO are prepared through its annual budgeting process. AEMO's 2021-22 Budget and Fees paper introduced two new fees for market participants (including retailers), namely:[8]

- IT upgrade and 5 minute settlements/global settlements; and
- DER integration program.

AEMO's budget states that the IT upgrade fee has been applied to recover the costs of the five-minute and global settlement rule changes and upgrades to related IT systems for the NEM. The DER fee category has been applied to recover the consolidated costs of the integration of DER into the NEM.

AEMO's budget does not set out the fees for 2022-23. The Regulator will use the fees applicable in 2021-22 as the best estimate for the calculation of the 2022-23 feed-in tariff rate unless the fees, or estimates of the fees, for 2022-23 are published before June 2022.

1.3.2.2 Ancillary service charges

Retailers pay ancillary services charges to AEMO based on the amount of wholesale electricity they purchase through the NEM. As the amount of wholesale electricity purchased through the NEM is reduced by exports from distributed generation, the liability of retailers for ancillary service fees is also reduced as they are calculated on a lower volume of wholesale electricity.

Given this, the Regulator intends to continue taking ancillary service charges into account in determining the feed-in tariff rate. In determining the value of ancillary service charges for the

[8] AEMO, *2021-22 AEMO Consolidated Budget and fees*, October 2021.

feed-in tariff, the Regulator would assume that the average cost of ancillary services will be consistent with the average over the most recent 12 month period.

1.3.3 Energy losses

As electricity flows through transmission and distribution networks to consumers, a portion of that electricity is lost as heat. These losses increase the further electricity has to travel. The result of this is that retailers must purchase sufficient electricity to satisfy customer demand as well as cover the losses associated with transporting it to customers. When electricity is purchased from distributed generation systems, it reduces the amount of electricity transported over long distances and therefore, network losses.

Recognising that retailers avoid purchasing additional energy to account for losses, it is appropriate, when determining the feed-in tariff rate, that the cost of purchasing electricity in the wholesale market is adjusted upwards for these losses.

AEMO is responsible for calculating the loss factors used in the NEM. Loss factors are calculated and fixed annually to reflect the marginal cost of network losses for load and generation transmission network connection points (marginal loss factors, or MLFs) and average losses for load connection points embedded within the distribution network (distribution loss factors, or DLFs). Generation in a network is allocated an MLF and supplemented by a DLF. DLFs are calculated each year by distribution network service providers (in Tasmania, by TasNetworks) and approved by the Australian Energy Regulator.

The Regulator has used Aurora Energy's estimates of distribution loss factors and marginal loss factors in its standing offer pricing proposal for 2022-23 to develop a loss factor for Tasmania. The 'loss factor' is then applied to the avoided cost of purchasing electricity in the wholesale market, to derive the cost saving.

In previous calculations of the feed-in tariff rate, loss factors were only applied to the wholesale electricity price, not the NEM fees and charges. This is because the NEM fees and charges were calculated in a way that used forecast load that was already adjusted for distribution losses. However, due to a small change in the way NEM fees and charges are estimated compared to previous periods, forecast load will no longer be used and therefore it will be necessary to adjust these charges for distribution losses in the calculation.

This approach is consistent with that of other jurisdictional regulators, such as the Essential Services Commission (ESC), that apply the loss factor to the avoided cost of purchasing electricity in the wholesale market (including market fees and ancillary service charges) to derive the cost saving.[9]

The Regulator intends to adjust the total avoided cost of wholesale electricity (including NEM management and ancillary service charges) for distribution losses when calculating the feed-in tariff rate. This small change to the formula for calculating the value of avoided costs will have virtually no effect on the feed-in tariff rate compared to the approach taken for the previous determination.

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[9] Essential Services Commission, *Minimum electricity feed-in tariff to apply from 1 July 2021: Final decision*, February 2021.

1.3.4 Network costs

Network costs comprise two major components, namely, transmission and distribution charges. These network costs, which include metering, are a major component of retailers' cost to supply electricity to their customers. The network usage fees, termed Transmission Use of System (TUoS) and Distribution Use of System (DUoS) fees, comprise fixed, daily charges, and per-unit volume charges.

Conceptually, network costs can be avoided through the supply of electricity from distributed generation, as less electricity is purchased from large scale generators and consequently, less electricity is transported through the transmission network to customers, minimising the volume charges.

However, state regulators across Australia have not supported any form of payment for avoided transmission costs as part of their feed-in tariff determinations. This is because there is no clear evidence that, system-wide, transmission network costs are lower as a result of increased electricity supply from distributed generation.

Additionally, if retailers were to pay an additional amount for exports to reflect any network cost savings, this would represent a net revenue loss to the retailer. This is because the network costs retailers pay to TasNetworks are not any lower as TasNetworks' charges are generally based on the amount of metered consumption at a customer's property, regardless of the source of that electricity. Therefore, a retailer receives no financial benefit from its sale of electricity from distributed generation under the current arrangements for metering and charging for the use of the transmission and distribution networks.

Furthermore, if there were network cost savings from increased electricity supply from increased distributed energy (whether as a result of increased exports or greater energy consumption by customers from their own electricity generation), this would be reflected in the revenue and pricing decisions of the Australian Energy Regulator (AER) in its regulation of network businesses.

However, the recent AER Transmission and Distribution Determination for TasNetworks did not include any discussion of potential network benefits from increased distributed energy generation, or any mechanism for TasNetworks to set lower network charges associated with increased consumption or exports of distributed energy. By contrast, the AER approved additional capital expenditure to enable TasNetworks to better adapt to increased distributed energy generation within the distribution network.[10]

As network costs are not avoidable costs to retailers and are therefore not relevant under the avoided cost to retailer methodology, the Regulator does not intend to include an adjustment for network costs within its feed-in tariff rate determination.

[10] Australian Energy Regulator, *TasNetworks 2019-24 Transmission and Distribution Determination, Final Decision,* April 2019.

1.5 Other impacts considered

The Regulator has also considered whether other direct impacts should be included in the feed-in tariff rate calculation.

The direct impacts considered include:

- Renewable Energy Target (RET) costs;
- retail operating costs; and
- business risk costs (retail margin).

These are discussed in detail below.

1.5.1 Renewable Energy Target (RET) costs

The Australian Government's Renewable Energy Target (RET) scheme creates demand for renewable energy by requiring liable entities, usually electricity retailers, to buy a set portion of their total annual electricity purchases from renewable sources. This is achieved through a market of tradable certificates which are created by large renewable power stations and the owners of small-scale systems with every megawatt hour of power they generate. The RET scheme is set to end in 2030.

The RET comprises two separate schemes: the Large Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES).

The LRET supports development of large scale wind and solar projects. Electricity retailers must purchase a set number of Large-scale Generation Certificates (LGCs) each year and surrender these to the Clean Energy Regulator (CER) to meet their legal obligations. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage (RPP) which is determined by the CER.

The SRES supports investment in small-scale technologies such as rooftop solar panels, solar hot water heaters and small-scale wind systems through the generation of Small-scale Technology Certificates (STCs). The SRES is an uncapped scheme such that all STCs created must be purchased by electricity retailers. The number of STCs electricity retailers must purchase and surrender over the course of each calendar year is calculated using the Small-scale Technology Percentage (STP) as determined by the CER.

The RPP and STP are applied to the amount of wholesale electricity purchased by the retailer in a calendar year, adjusted for the applicable distribution loss factors.

As RET costs are calculated on the amount of electricity purchased each year by a retailer, whether from roof top solar PV systems, other distributed generation systems or from large scale generators through the NEM, retailers are unable to avoid RET costs. As such, RET costs should not be included in the feed-in tariff rate under the avoid-cost methodology.

Additionally, as noted by the NSW regulator, IPART, it would not be appropriate to provide feed-in tariff customers with a premium on the feed-in tariff rate (as compensation for the value of the renewable energy generated) as feed-in tariff customers already receive the

benefit of offsetting the value of the renewable energy certificates against the installation costs of their solar PV system.[11]

Submissions to previous investigations have suggested that the Regulator's benchmark should include the environmental benefits that solar generated electricity provides compared to other forms of generation. However, retailers do not capture avoided adverse externalities from supplying solar generated electricity. This means that if the Regulator included a value for environmental benefits in the feed-in tariff that is paid by retailers, retailers may incur losses, or lower than acceptable profits, in retailing to feed-in tariff customers. This could lead to higher retail prices to other customers and would deter retailers from selling to feed-in tariff customers.

Additionally, in its recommendation on feed-in tariffs, the Queensland Productivity Commission noted that investors already receive a subsidy from the SRES for emissions reduction and any additional subsidy paid through a feed-in tariff would be poorly targeted and result in a high cost of abatement, as well as large cross-subsidies between electricity consumers.[12] This has also been seen within other jurisdictions. In NSW for example, the subsidy paid by non-solar customers has been estimated at around $41 per year for an average bill, and another $55 per year for 'green costs', which includes the subsidies provided under the RET.[13] As such, the Regulator does not consider it appropriate to provide an additional subsidy through the feed-in tariff.

The Regulator does not intend to take RET costs into account when determining the feed-in tariff as these costs are unavoidable to the retailer. This is consistent with the findings of other regulators and the advice provided by the CER as part of the feed-in tariff reviews conducted in other jurisdictions.[14]

1.5.2 Retail operating costs

Retail operating costs are those costs incurred in running a retail electricity business. These include:

- costs associated with billing and revenue collection;
- call centre costs;
- customer information costs;
- corporate overhead costs;
- regulatory compliance costs; and
- marketing costs.

These costs tend to vary in proportion to the number of customers served, rather than the volume of electricity sold. Furthermore, these costs are not lower if retailers' customers are

11 IPART, *Solar feed-in tariffs - Solar feed-in tariff benchmarks, Final Report, June* 2021.

12 QPC, *Solar feed-in pricing in Queensland, Final Report*, June 2016.

13 AEMC, Residential electricity price trends report - End-year 2020, 21 December 2020, p 16.

14 See IPART, *Solar feed-in tariff benchmarks, Final Report* (June 2021), page 21 and QCA, *Estimating a fair and reasonable solar feed-in-tariff for Queen*sland (2013), pages 23 and 24.

supplied with electricity from distributed generation rather than from large-scale generation purchased through the NEM.

Regulators in other jurisdictions have examined whether retailers' operating costs for serving solar PV system customers is higher than the cost of serving other customers. However, findings have been generally inconclusive.

The AER, for example, found that, due to lower volume requirements, solar customers were generally less profitable than non-solar customers.[15] Conversely, Frontier Economics found no clear evidence that the costs of arranging retail supply are affected by solar PV exports.[16] Both IPART and the QCA made similar remarks in their recent feed-in tariff reports, noting that retailers still incur operating costs when they supply electricity services to customers, regardless of where and how the electricity is generated.[17,18]

The Essential Services Commission (Victoria, ESC) also noted recently in its draft decision on feed-in tariffs for 2022 that solar customers are electricity generators, not electricity retailers; they do not incur the costs that electricity retailers do and it would not be appropriate to compensate solar customers for costs they do not incur when exporting electricity to the grid.[19]

Given the inconclusive evidence for including either a reduction or increase in retail operating costs, the Regulator does not intend to include any of these costs in the calculation of the regulated feed-in tariff rate.

1.5.3 Business risk costs (retail margin)

Retailers assume a level of risk in providing electricity retail services and therefore seek to receive a return on their investment. The retail margin is intended to compensate investors for committing capital to a business and for accepting the range of commercial risks they face. In relation to regulated standing offer prices, it has been a percentage applied to the sum of the retailer's costs as reviewed and approved by the Regulator.

A retailer's business risks are not reduced or increased by the sale of electricity sourced from distributed generation rather than through the NEM. As there is no change in the business risks faced by retailers, it is not appropriate to adjust the feed-in tariff rate for any retailer-risk related reason. This is the same conclusion reached by regulators in other jurisdictions.[20]

The Regulator proposes to exclude any component of the retail margin from the calculation of the feed-in tariff rate.

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15 AER, State of the Energy Market 2018, (December 2018), page 62

16 Frontier Economics, *2018 Solar Feed-in Tariff Review – A Final Report prepared for IPART*, March 2018.

17 IPART, *Solar feed-in tariffs, The value of electricity from small-scale solar panels in 2018-19*, Final Report, June 2018.

18 QCA, Determination 2018–19 Solar feed-in tariff, May 2018.

19 ESC 2021, *Minimum feed-in tariff to apply from 1 July 2022: Draft decision*, 2 December 2021.

20 See IPART, *Solar feed-in tariffs, The value of electricity from small-scale solar panels in 2018-19*, Final Report, June 2018 and QCA, *Estimating a fair and reasonable solar feed-in-tariff for Queensland* (2013), page 28.

1.6 Indirect impacts considered

The Regulator has also considered whether indirect impacts should be included in the feed-in tariff rate calculation.

The indirect impacts considered include:

- reductions in average network loss factors as a result of increased distributed generation;
- the impact on wholesale electricity prices of increased distributed generation;
- the deferral of network augmentation costs;
- the potential need for network reinforcement costs;
- the environmental benefits of renewable energy; and
- security of supply.

1.6.1 Average network loss factors

As discussed in Section 1.3.3, given that electricity exported from distributed generation reduces the need to transport electricity over long distances, the energy losses that normally occur when electricity is transported across the transmission and distribution network are reduced. The Regulator has included these specific energy losses as a direct financial impact for retailers when determining the feed-in tariff rate.

However, Tasmanian electricity users, both with and without PV systems, may also derive an indirect benefit through a reduction in the average network loss factors. The more electricity produced and used from distributed generation (whether it is used directly by the system owners or exported to the grid), the less electricity is purchased from large-scale generators across the NEM. This means that less electricity may be transported across the transmission and distribution networks, possibly resulting in lower average network loss factors. As loss factors are considered when setting retail prices, lower loss factors result in lower costs and prices for all customers, all else being equal.[21]

However, it is currently unclear as to the extent to which losses within the network may change with increased use of distributed generation. More importantly, if all customers do indeed benefit from lower tariffs and an allowance to reflect the benefit is included in the feed-in tariff rate, the benefits would be effectively provided twice, at the expense of the retailers.

Given this, the Regulator considers that any reduction in costs due to lower average network loss factors should not be included in determining the feed-in tariff rate.

1.6.2 Impact on wholesale electricity prices

In the wholesale electricity market, generators bid to supply electricity at designated prices every five minutes of every day. These bids are made according to the cost of generation. In the NEM, AEMO conducts the market through a centrally-coordinated dispatch process, so that generators with the lowest marginal costs (those who make the lowest bids) are the first

[21] See IPART, *Solar feed-in tariffs, setting a fair and reasonable value for electricity generated by small scale solar PV units in NSW, Final Report* (2012), page 78.

ones to be brought online to meet demand, and generators with the highest marginal costs are brought online only when necessary (the merit order). Dispatching generation in this manner minimizes the cost of production of electricity.

As distributed generation reduces the total amount of electricity required to be purchased from the wholesale market, demand may be met by generators bidding lower in the merit order, thereby lowering spot prices (the merit order effect). Retailers, and subsequently customers, receive the benefits of lower wholesale electricity prices by paying less for an equivalent amount.

Regulators in other jurisdictions have also considered the benefit that distributed generation can provide in lowering the wholesale spot price for electricity. They have generally concluded that lower spot prices are a normal part of the competitive market process which occurs when the supply of a good or service increases. IPART, for example, noted that the same merit order impact can occur when a new, non-distributed generator enters the market or if consumers reduce demand.[22] If retailers or electricity customers were required to reward small-scale distributed generation owners if their systems reduce wholesale spot prices, other market participants, including non-renewable electricity generators and consumers, should also be eligible for rewards when their behaviour affects the merit order. IPART continued:

> … that solar customers should be treated consistently with other electricity generators and so should not get a higher or lower tariff to reflect their impact on wholesale prices. For example, a new wind turbine that contributes to reduced wholesale spot prices does not receive any additional payment to reflect the lower wholesale price. It takes the same market price as all other generators. This also means that all consumers benefit from lower prices.[23]

The Queensland Productivity Commission agreed with this view, also noting that paying customers with distributed energy generation systems for any reduction in wholesale market prices would likely result in a net increase in electricity prices for all consumers.[24]

In Tasmania, distributed generation during the day can allow Hydro Tasmania to build up its storages to generate energy at later times or export to Victoria when prices are high. While it is true that this may result in lower wholesale electricity prices in Tasmania overall (provided there are no water storage supply issues), the final impacts on price are currently unclear.

More importantly, if customers benefit from lower wholesale electricity prices and a payment to reflect the benefit is returned to PV customers, the benefits are effectively provided twice, at the expense of the retailer and those who do not have distributed generation systems.

The Regulator does not intend to take into account the impact of distributed generation on the wholesale spot price from the merit order effect, or on Hydro Tasmania's storages when determining the feed-in tariff rate.

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22 IPART, *Solar feed-in tariff benchmarks, Final Report April 2020-2021*, April 2020.

23 IPART, *Solar feed-in tariff benchmarks, Final Report*, June 2021.

24 QPC, *Solar feed-in pricing in Queensland, Final Report*, June 2016.

1.6.3 Potential deferral of network augmentation costs

The increased uptake of distributed generation may potentially lead to a reduction in future network costs depending on the specific location, level of penetration and local load characteristics. As exports from distributed generation usually do not use the transmission network or require electricity to travel long distances along the distribution network, some of this investment could potentially be deferred, avoiding additional network costs for all customers.

However, there does not currently seem to be a need for significant network augmentation in Tasmania. TasNetworks noted in its submission to the Draft Tasmanian Renewable Energy Action Plan 2020 that:

> "While distribution networks in other parts of Australia are reaching the limits of their capacity to accept the energy injected by micro-embedded generators, Tasmania's distribution network still has the capacity to host higher levels of Distributed Energy Resources (DER)."

In order for solar PV exports to contribute to decreased network investment, solar PV exports would need to occur at times and in places where the exported electricity contributes to meeting peak demand, enabling the deferral of investment that would otherwise need to occur.

However, in Tasmania, peak demand typically occurs during early morning in the winter period. As solar energy is generated only during daylight hours, and peaks during the summer months, it does not make a significant contribution to meeting peak demand. Consequently, networks still need to be sized to meet peak demand regardless of whether or not solar energy is generated. As such, there would not appear to be any deferred network augmentation costs avoided due to the connection of small-scale distributed energy installations to the network.[25] Furthermore, regulators in other jurisdictions have noted that, even in circumstances where peak demand and peak solar output do coincide, potential benefits from deferred network investment are either small or difficult to measure.[26]

Finally, analysis by the QPC noted that, in Queensland, while solar PV may be able to defer network expenditure in some specific locations, any savings that may arise are unlikely to outweigh the additional costs incurred from integrating solar PV into the network.[27] These costs arise from the variable nature of distributed energy, which necessitate significant changes to the way the power system operates in order to maintain grid stability and reliability. Given the disagreement related to the effect of distributed generation on the need for network augmentation, the Regulator considers it inappropriate to provide an allowance in the feed-in tariff.

Additionally, due to the variability of distributed generation to the network, across both location and time, any single-rate feed-in tariff could not adequately capture any potential value associated with deferred investment. A study by the ESC into the network value of distributed generation, for example, concluded that there was "no single network value of

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25 See TasNetworks' *Annual Planning Report 2020* (page 6).

26 See for example, IPART, *Solar feed-in tariffs -The value of electricity from small-scale solar panels in 2018-19, Final Report,* June 2018.

27 QPC, *Solar feed-in pricing in Queensland - Final Report*, June 2016.

distributed generation".[28] As such, it is not appropriate to capture a benefit to the network within the feed-in tariff.

There may be several other reasons why a network extension or augmentation may not occur. These may include, for example:

- investment in energy efficient technology by some customers reducing overall demand;
- changes in economic conditions;
- structural changes in Tasmania's industries; and
- government policy changes with regards to network standards.

Under these circumstances, no individual party is rewarded, or charged, for their potential contribution towards avoided network investment. All parties benefit from the avoided network expenditure, similar to how all parties benefit from reduced average loss factors and wholesale electricity prices through the merit order effect, as discussed in Section 1.5.2. As such, including the value of these potential benefits in the feed-in tariff rate paid to customers with distributed generation would double count the benefits at the expense of the retailer and ultimately customers.

The Regulator considers that the benefits of avoided network investment should accrue to all parties and does not intend to take this factor into account when determining the feed-in tariff rate.

1.6.4 Potential need for network reinforcement costs

Increased installation of distributed generation has the potential to add additional costs and risks to the operation of electricity networks. This is particularly the case for intermittent distributed generation systems such as solar PV.

The Australian Energy Regulator's 2019 Consultation Paper on DER integration expenditure[29] noted increasing levels of solar PV can have adverse impacts on networks. The two primary impacts are voltage rise at certain times (voltages on electricity networks can rise as PC systems inject their energy into the system) and overload (eg if the volume of locally produced energy is greater than the capacity of the network assets).

These issues for the network arise because solar energy is not able to respond, with reasonable certainty, to the dynamic needs of the power system. For example, solar energy cannot be relied upon to address frequency deviations within the power system and therefore cannot contribute to maintaining system stability.

Additionally, because the majority of solar inverters have been designed to disconnect themselves from the network if the system frequency is not within a pre-defined operating band, there is the potential for many inverters to simultaneously disconnect from the system, reducing exports to the grid, and exacerbating the effects of any initial frequency deviation.

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[28] ESC, *The network value of distributed generation, Inquiry Stage 2 Final Report*, February 2017.

[29] AER, *Assessing Distributed Energy Resources (DER) Integration Expenditure* consultation paper, 29 November 2019

This adds risks to the network in terms of maintaining a continuous stable flow of electricity to customers.[30]

Distribution network operators have also observed that high levels of solar PV in parts of the grid are causing issues related to network stability and voltage control. For example, TasNetwork's submission to the AER's enquiry into DER integration expenditure stated:

> Although TasNetworks' expenditure on DER integration has been modest to date compared to its expenditure overall, we have already seen instances where customers' use of DER- mainly in the form of photovoltaic (PV) solar panels - has required localised network augmentation, such as the installation of uprated transformers to maintain voltage stability, the cost of which has for the most part been borne by the wider customer base, rather than the customers installing DER. (sub. page 1).

Regulators in other jurisdictions have also noted that large volumes of solar exports have the potential to impose higher network costs due to additional investment required to support the bidirectional flows of electricity to handle the volume of solar exports.[31] However, the Australian Energy Market Commission's (AEMC) recent determination recognised that supporting growing levels of DER does not necessarily mean that DNSPs will require significant expenditure; it found that there are a number of relatively low-cost steps that can improve a network's capacity to connect more DER before investing in network expansion.[32]

However, while this is the case, it is important to note that frequency control issues can also potentially arise due to the connection of other generation sources including traditional synchronous generators, wind farms, and High Voltage Direct Current (HVDC) interconnectors such as Basslink.

At present, it is difficult to predict when system frequency issues may arise due to the export of electricity from solar PV systems. The precise nature of the risks and therefore any costs associated with rectifying resultant issues cannot currently be quantified. This is an ongoing issue which is being investigated not only in Tasmania, but in other mainland jurisdictions.

Unless retailers incur a network charge that applies to its customers that export to the grid, and the retailers have no other way of recovering this cost, the feed-in tariff should not take account of any of these system-level costs.

Otherwise, similar to the points made in section 1.5.3, including a value for potential network reinforcement costs in the determination of the feed-in tariff rate (which would reduce the rate) would be double counting the cost at the expense of customers with distributed generation. This matter is also discussed in section 1.6.

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30 In, early 2015-16, Standards Australia undertook consultation on proposed revised minimum performance and safety standards for the design, construction and operation of inverters intended for use in inverter energy systems used for the injection of electric power through an electrical installation connected to the electricity distribution network. The proposed replacement standards are AS/NZS 4777.1 Grid connection of energy systems via inverters - installation requirements and AS/NZS 4777.2 Grid connection of energy systems via inverters - inverter requirements.

31 IPART, *Solar feed-in tariff benchmarks - Final Report*, June 2021, page 21.

32 AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021.

1.6.5 Environmental and health benefits

There are a number of environmental benefits associated with renewable energy compared to traditional forms of power generation such as coal and gas fired generation. These include reduced carbon emissions and reduced dependence on fossil fuels. It has been argued that the feed-in tariff should act as a mechanism for promoting distributed energy generation systems due to the associated environmental benefits.

There are challenges associated with calculating the value of any environmental and health benefits arising from distributed generation. For example, the ESC, in its report on the energy value of distributed generation, considered a number of potential environmental and social benefits including avoided pollution, avoided resource consumption and extraction, increased choice and competition and enhanced wellbeing. The ESC concluded that the displacement of emissions-intensive generation by distributed generation is difficult to measure and therefore, the only area of environmental or social benefit that could be quantified with reasonable confidence is the *volume* of greenhouse abatement for various forms of distributed generation.[33]

This suggests that feed-in tariffs are not a suitable mechanism to compensate owners of distributed generation for the environmental or health benefits produced, as they are designed to facilitate payments for electricity that is exported (ie net output).

Additionally, as noted earlier, customers with distributed generation systems already receive financial compensation for emissions abatements and other environmental benefits provided by renewable energy, at least up to 2030, by submitting the certificates provided through the SRES arrangements.[34] The compensation provided to these customers through SRES already includes an inherent value for health benefits.

Under the 'net financial benefits to retailers' method of determining the feed-in tariff rate, any potential additional benefits (if they are able to be quantified) should not be included as the retailers cannot recover the value of the payments made unless there is a direct subsidy from a level of government.

Given this, the Regulator does not intend to include an estimate of the value of additional potential environmental benefits in the calculation of the feed-in tariff rate.

1.6.6 Security of supply

Additional generation from distributed energy resources reliance on Tasmania's hydro generation by displacing the potential energy of water in Hydro Tasmania's storages. As the majority of Tasmania's energy is generated by Hydro, this results in improved security of supply, particularly in drought conditions or during prolonged Basslink outages.

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33 ESC, *The Energy Value of Distributed Generation, Distributed Generation Inquiry Stage 1 Final Report*, August 2016.

34 Queensland Productivity Commission, *Solar Feed-in Pricing in Queensland: Draft Report*, March 2016, page 87.

However, given that total exports from Tasmanian grid-connected solar PV systems for 2020-21 was around 135 GWh (ie around 1.8 per cent of total energy in storage[35]), the Regulator considers that, at present, the impact is small.

Additionally, current regulatory arrangements do not provide a mechanism whereby energy security benefits attributable to customers with distributed generation systems can be recovered by the retailer. Any payment to these customers would therefore be at the expense of retailers or borne by the broader customer base through higher prices.

Given this, the Regulator does not intend to include an estimate of security of supply benefits in the calculation of the feed-in tariff rate.

1.7 AEMC's draft ruling to allow distributed network service providers to charge for export services

The Australian Energy Market Commission (AEMC) is an independent statutory body that makes and amends the rules that underpin the National Electricity market. In July 2020, the AEMC received three rule change requests seeking to amend the National Electricity Rules (NER) applying to the economic regulation of distribution network service providers (DNSPs) in the NEM. The requests sought to better integrate distributed energy resources such as solar systems in a way that benefits all electricity users.

On 12 August 2021, the AEMC made a final determination[36] on updates to the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to integrate distributed energy resources (DER) such as small-scale solar and batteries more efficiently into the electricity grid.

The AEMC's package of reforms under the final rules has three key components:

- clear obligations on distribution network businesses to support energy flowing both ways;
- enabling new network tariff options that reward customers; and
- strengthening consumer protections and regulatory oversight by the AER.

The rule changes do not mandate export charges. Implementation by the networks is optional. Distribution businesses are required to develop their pricing plans and options, including an export tariff transition strategy if introducing export pricing. Distributors are also required to consult with their customers and their plans must be approved by the AER.

Customers will not see any impacts from this rule change until 1 July 2025 at the earliest. Distribution network service providers need to consult extensively with their customers and have their pricing structures approved by the AER before levying any export charges.

According to its website, TasNetworks is looking to implement a network tariff to support customers who own electric vehicles and other distributed energy resources (such as solar PV or battery technology). TasNetworks states that it is currently seeking to understand electricity customers' awareness of current network tariff options and identify where there are gaps in supporting customers who take up new and innovative technologies. TasNetworks has advised

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35 7 305 GWh currently in storage. Source: Hydro Tasmania, hydro.com.au/water, accessed 14 December 2021

36 AEMC, *Access, pricing and incentive arrangements for DER*, Rule determination, 12 August 2021.

that, while it is looking at trial network export charges to assess how these charges might operate, they currently have no plans to charge Tasmanian customers for exports to the grid.

IPART's recent issues paper on solar feed-in tariff benchmarks[37] noted the AEMC's rule change and has formed a preliminary view that changes to its approach to valuing solar exports are not needed, but that it will seek stakeholder views and monitor the developments in the market as it finalises its approach to setting feed-in tariffs, and for future years.

The Regulator also considers changes to its approach to determining the feed-in tariff rate are currently not needed in response to the AEMC's ruling. The Regulator will monitor closely developments in this area and it is anticipated that this issue will be considered in forthcoming feed-in tariff investigations.

[37] IPART, *Solar feed-in tariff benchmarks - Issues paper*, February 2021.

2 DRAFT DECISION

This Chapter sets out the Regulator's draft decision on the feed-in tariff rate to apply on mainland Tasmania from 1 July 2022 to 30 June 2025.

2.1 Provisional estimate of the feed-in tariff rate

The Regulator's draft decision is to calculate the feed-in tariff rate using the avoided cost method outlined in this Report.

Under the intended approach, the following components are included in the calculation of the annual feed-in tariff rate:

- wholesale electricity price;
- avoided NEM market fees and ancillary service charges; and
- avoided distribution and transmission energy losses.

It is intended that the feed-in tariff rate will be calculated to three decimal places in line with the presentation of standing offer prices.

2.1.1 Wholesale electricity price

The Regulator intends to apply the wholesale electricity price (WEP) used in determining standing offer prices in Tasmania in estimating the wholesale electricity price component of the feed-in tariff rate.

In late May 2022, the Regulator will calculate the WEP for 2022-23. It is intended that this would be the wholesale electricity price used to calculate the feed-in tariff rate for the 2022-23 financial year. The Regulator's current estimate of the WEP for 2022-23 is $61.84/MWh.

2.1.2 Estimate of the avoided NEM market fees and ancillary service charges

AEMO's current budget does not provide an estimate of the fees and charges for retailers for 2022-23. Therefore, the Regulator intends to use the fees and charges applicable in 2021-22 as the best estimate for 2022-23 unless the fees and charges, or estimates, become available before June 2022. .

The Regulator's current estimate of the relevant 2022-23 NEM market fees is $0.550/MWh.[38]

The cost of ancillary services is recovered from market participants. AEMO publishes data on a weekly basis showing the cost recovery rate for ancillary services. For the purpose of determining a feed-in tariff that applies from 1 July 2022, the Regulator expects that the

[38] AEMO, *2020-21 Budget and fees*, October 2020. Market fees include general fees, allocated fees for market customers, IT upgrade and 5MS/GS compliance and DER integration for market customers.

average cost of ancillary services in 2022-23 will be consistent with the average from May 2020 to April 2021, escalated by growth in CPI.

The Regulator's current estimate of the relevant 2022-23 ancillary services fees is $0.655/MWh.

When the cost of ancillary services are added to the relevant NEM market fees, the value of NEM market and ancillary service charges avoided when a retailer obtains electricity from a small-scale electricity generator is $1.204/MWh. Table 2.1 provides a breakdown of this calculation as it applies to standing offer customers in Tasmania.

Table 2.1 Estimate of market and ancillary service fees, 2022-23[39]

Component	Fee ($)	c/kWh
National Electricity Market fees	$0.40000/MWh	0.040
IT upgrade and 5MS/GS compliance	$0.12325/MWh	0.012
DER integration	$0.02623/MWh	0.003
Total AEMO market fees	**$0.5495/MWh**	**0.055**
Ancillary service charges	$0.6549/MWh	0.065
Total AEMO fees and charges	**$1.2044/MWh**	**0.120**

Source: AEMO, 2021-22 AEMO Budget and fees, October 2021

2.1.3 Estimate of the avoided distribution and transmission energy losses

Using data provided by Aurora Energy as part of its standing offer pricing proposal for 2022-23, the Regulator estimates a customer weighted line loss factor of 1.0531. The total loss factor is applied to the wholesale electricity price and the distribution loss factor is applied to the AEMO market fees to estimate the value of losses in the calculation of the feed-in tariff rate. Table 2.2 sets out the inputs to this calculation.

Table 2.2 Inputs for calculating loss factors

Component	
Average marginal loss factor (MLF)	0.9951
Distribution loss factor (DLF)	1.0583
Total loss factor	**1.0531**

Source: Aurora Energy, *preliminary submission to the 2022 Price-regulated Retail Service (Standing Offer) Pricing Investigation,* October 2021.

The Regulator intends to update its estimates of loss factors if updated inputs become available before making its final determination in June 2022.

[39] Table may not add due to rounding. If available in time, figures will be updated when AEMO's final budget and fees for 2022-23 are published.

2.2 Updating the feed-in tariff rate

The Regulator will determine the feed-in tariff rate for each of the 2022-23, 2023-24 and 2024-25 financial years using the method and formula outlined in the Determination.

The feed-in tariff rate to apply from 1 July 2022 for the 2022-23 financial year will be calculated by the Regulator and published in mid-June 2022.

2.3 Provisional estimate of the feed-in tariff rate for 2022-23

The regulated feed-in tariff for mainland Tasmania for 2022-23 is provisionally estimated to be 6.665 cents per kilowatt hour. Table 2.3 below sets out how each component contributes to the overall feed-in tariff rate under the Regulator's intended methodology.

Table 2.3 Provisionally estimated regulated 2022-23 feed-in tariff rate for mainland Tasmania (c/kWh)

Component	c/kWh
Wholesale electricity price	6.184
Avoided NEM management and ancillary service charges	0.120
Value of avoided distribution and transmission and energy losses	0.361
Provisional feed-in tariff rate	**6.665**

The feed-in tariff rate estimate will be updated with the most recent data when the Regulator releases its final report in April 2022. The final feed-in tariff rate for 2022-23 will be calculated in mid-June 2022 and is to apply from 1 July 2022 until 30 June 2023.

A Draft Determination, the *Draft Regulated Feed-in Tariff Rate Determination, January 2022*, has been published as Attachment 1 to this Draft Report. The Draft Determination is also available, separately, on the Regulator's website: www.economicregulator.tas.gov.au.

APPENDIX A: LEGAL CONTEXT

The *Electricity Supply Industry Act 1995* (ESI Act) and the *Electricity Supply Industry (Price Control and Related Matters) Regulations 2013* (Pricing Regulations) set out the legislative framework for feed-in tariffs and the determination of the Feed-in tariff rate.

Before the Regulator makes a determination, Regulation 47B of the Pricing Regulations requires the Regulator to conduct a pricing investigation. The Regulator's Notice of his intention to conduct an investigation was published on 30 June 2021.

Feed-in tariff customers

Sections 44C and 44D of the ESI Act define two types of feed-in tariff customers in respect of premises with qualifying systems: standard and transitional.

A qualifying system is defined in section 44B of the ESI Act as a system that:

- generates electricity from either solar, wind or water;
- complies with Australian Standard AS 4777; and
- has a maximum generating capacity of 10 kVA for single-phase installations, or 30 kVA for three-phase installations.[40]

There are no longer any transitional feed-in tariff customers.

Feed-in tariff rate

Section 44G of the ESI Act requires the Regulator to determine the feed-in tariff rate to be paid by authorised retailers to standard feed-in tariff customers for energy exported to the electricity grid.

The feed-in tariff rate may be expressed as either a rate in relation to a kWh of electricity, or a method for determining a rate in relation to a kWh. Differential feed-in tariff rates that vary by premises, class or other factors can also be set out in the Regulator's determination.

Principles to be taken into account in making feed-in tariff rate determinations

Under section 44H of the ESI Act, the Regulator is required to consider the following matters when making a feed-in tariff rate determination:

(a) the fair and reasonable value to authorised retailers of electricity supplied to the distribution network by feed-in tariff customers;

[40] Customers with systems with generating capacity greater than 10 kW can negotiate a market feed-in tariff rate with their retailer.

(b) the net financial benefit, to authorised retailers, of electricity supplied to the distribution network by feed-in tariff customers, having regard to the costs of authorised retailers, including, but not limited to including –

  (i) the costs to authorised retailers of purchasing wholesale electricity; and

  (ii) other costs of authorised retailers in operating their retail electricity businesses;

(c) the other costs, or other benefits, that –

  (i) include those related to the distribution networks or transmission networks; and

  (ii) result, either directly or indirectly, from the supply of electricity to distribution networks by qualifying systems at premises of small customers;

(d) the National Principles for Feed-in Tariff Arrangements, as those Principles apply from time to time;

(e) any arrangements of the Commonwealth, whether legislative or otherwise, in relation to the pricing of carbon emissions or other mechanisms to reduce the use of carbon-emitting fuels;

(f) the principle that the feed-in tariff rate specified in the determination should not have the effect that any customer would effectively be cross-subsidising any other customer;

(g) approaches, methodologies, findings or recommendations, taken or made in other jurisdictions for determining fair and reasonable feed-in tariff rates;

(h) any prescribed matters; and

(i) any other matter the Regulator thinks relevant.

APPENDIX B: FEED-IN TARIFFS IN OTHER JURISDICTIONS

This Appendix provides an overview of decisions made recently by regulators in other jurisdictions with respect to calculating the value of energy exported to the grid by customers with solar PV systems.

New South Wales

In New South Wales, while electricity retailers are not obliged to offer customers a feed-in tariff for their solar exports, many do. To help retailers and customers decide whether market offers in relation to feed-in tariffs are reasonable, the Independent Pricing and Regulatory Tribunal of NSW (IPART) has set a 'benchmark range' for solar feed-in tariffs for each year since 2012.

In November 2020, the NSW Government asked IPART to continue setting benchmarks for solar feed-in tariffs annually, for the three financial years from 2021-22 to 2023-24. IPART was also asked to set time-dependent benchmark ranges for solar feed-in tariffs.

IPART has adopted the wholesale market method to determine its 'all-day solar' and 'time-dependent' feed-in tariff benchmarks. For 2021-22, IPART has set a benchmark range of 4.6 to 5.5 cents per kilowatt hour for 'all-day solar' exports, based on a forecast of the average price retailers would pay for solar exports across the day (weighted by solar output) as if they were buying the energy on the wholesale market.[41]

The all-day feed-in tariff rate is calculated according to the following formula:

(Average forward price (ASX baseload price) x solar multiplier x network loss factor) + NEM fees and charges.

The lower and upper bounds for average wholesale electricity prices are forecast using NSW baseload electricity futures contracts traded on the Australian Stock Exchange (ASX). The lower bound utilizes a 40-day average price (and a five per cent adjustment to remove the contract premium), while the upper bound uses a volume-weighted average of all historical trades. The solar multiplier was calculated using the average solar weighted and time weighted prices from three years of historical data.

The 2021-22 benchmark range for 'time-dependent solar' exports is between 4.3 to 5.1 cents per kilowatt hour for the 'offpeak' period from 6 am to 3 pm and between 4.3 and 14.5 cents per kilowatt hour at other times, varying by the time block. However, IPART noted that over 90 per cent of solar exports would occur in the lowest price time block (from 6 am to 3 pm).

41 IPART, *Solar feed-in tariff benchmarks, Final Report,* June 2021.

Queensland

Feed-in tariff arrangements in Queensland vary between South East Queensland (SEQ) and regional Queensland. In SEQ, individual retailers determine the value of the feed-in tariff paid to solar PV customers as part of their competitive market offers.[42] In regional Queensland, where there is limited competition, the Queensland Competition Authority (QCA) sets the feed-in tariff rate.

Queensland's Solar Bonus Scheme (SBS) pays eligible customers a prescribed feed-in tariff for surplus electricity generated from small-scale solar PV systems and exported to the grid. The SBS was closed to new customers on 30 June 2014 and replaced with a mandatory feed-in tariff for regional Queensland,[43] determined by the QCA each financial year in a Direction from the Minister for Energy, Biofuels and Water Supply (the Minister).

The QCA applies the direct financial benefit to retailer method for estimating a fair and reasonable feed-in tariff rate and, for 2017-18, estimated a feed-in tariff rate of 10.102 cents per kilowatt hour.[44]

In January 2021, the Minister directed the QCA to set the feed-in tariff rate for small-scale solar PV owners in regional Queensland for 2021–22, consistent with the methodology used for 2020-21.

The QCA adopts the direct financial benefit to retailer method for estimating a fair and reasonable feed-in tariff and, for 2021-22, estimated a feed-in tariff rate of 6.58 cents per kilowatt hour.[16]

On 29 January 2019, the Minister directed the QCA to provide advice on a time-dependent solar feed-in tariff for 2019-20 in regional Queensland. The QCA's impact analysis suggested that typical solar PV customers in regional Queensland were unlikely to benefit from accessing a time-varying solar price, in comparison with the flat-rate feed-in tariff. No direction has been made for 2021-22

Victoria

Under section 40FBB of the *Electricity Industry Act 2000* (Vic), the Essential Services Commission (ESC) is required to determine one or more feed-in tariff rates that electricity retailers must pay their customers for the electricity they export to the grid, whether the generation facility uses wind, solar, hydro or biomass.

In making its determination, the ESC is required to take the following factors into account:

- prices of electricity in the wholesale electricity market; and
- any distribution and transmission energy losses avoided in Victoria by the supply of small renewable energy generation electricity.

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42 Queensland Productivity Commission, *Solar feed-in pricing in Queensland - Final Report*, June 2016.

43 The QCA is not required to determine a feed-in tariff rate to apply to customers in South-East Queensland in recognition of the competition that exists between retailers operating in that market.

44 QCA, *Solar feed-in tariff for regional Queensland,* Final Report, May 2017.

Following an inquiry conducted by the ESC in 2016 on the value of distributed generation, legislation was amended in 2017 to allow the ESC to set time-varying feed-in tariffs using a wholesale market method to set the underlying feed-in tariff rate. In 2017, the Victorian Government also issued an Order in Council specifying a method for determining the social cost of carbon, which is added to the single-rate and time-varying feed-in tariff rates.

The minimum feed-in tariff rates to apply in Victoria from July 2022 have been calculated by the ESC using the formula:

(Average wholesale electricity pool price + avoided market fees and ancillary service charges) x network losses + value of avoided social cost of carbon

The ESC's most recent decision sets out a single-rate feed-in tariff for 2021-22 of 6.7 cents per kilowatt hour and time-varying feed-in tariff with off-peak, shoulder and peak rates of 6.7, 6.1 and 10.9 cents per kilowatt hour respectively.[45] Retailers are required to offer either a single-rate feed-in tariff or time-varying feed-in tariff rates. All rates include 2.5 cents per kilowatt hour for the avoided "social cost of carbon", set by the Victorian Government.

South Australia

Under section 25 of the *Essential Services Commission Act 2002* (SA) the Essential Services Commission of South Australia (ESCOSA) may make pricing determinations. Further, in accordance with section 35A(1)(ba) of the *Electricity Act 1996* (SA), ESCOSA may determine feed-in tariffs in relation to electricity fed into a distribution network having regard to the fair and reasonable value to a retailer of electricity fed into the grid (section 35A(2a) of that Act).

In 2016, ESCOSA announced its decision to no longer set a minimum amount for the South Australian retailer-paid feed-in tariff (R-FiT) scheme, from 1 January 2017. Instead, each electricity retailer is required to determine the R-FiT amount and structures it will pay to its solar customers for electricity fed into the distribution network. Retailers are required to demonstrate publicly how their offers provide benefits to solar customers.[46]

ESCOSA states that it will continue to monitor retailers' offers to solar customers in order to determine whether or not it is appropriate to set a minimum R-FiT amount in the future.

Market offers by electricity retailers in South Australia include feed-in tariff rates for small customers of 8 - 16 cents per kilowatt hour (AGL), 10.5 cents per kilowatt hour (Energy Australia), 10.2 cents per kilowatt hour (Diamond), and 8 and 15 cents per kilowatt hour (Origin - Standard and Solar Boost, respectively).

Western Australia

Feed-in tariffs under the Western Australian Distributed Energy Buyback Scheme (DEBS) pay for excess electricity generated by small-scale solar photovoltaic (PV) or wind power systems. DEBS replaced the Renewable Energy Buyback Scheme (REBS) from 8 September 2020 for new and upgraded distributed energy systems. The most significant change between the two schemes is that DEBS introduces time-of-export payments.

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45 ESC, Minimum electricity feed-in tariffs to apply from 1 July 2021, Final decision, 25 February 2021.

46 ESCOSA, *Retailer feed-in tariff - Review of regulatory arrangements - final decision*, December 2016.

Under Western Australia's *Electricity Industry (Licensing Conditions) Regulations 2005*, government-owned retailers (Synergy and Horizon Power) must offer eligible customers a buyback scheme. According to requirements, the retailers establish their own terms and conditions (including rates) for buying excess energy and are responsible for running the Renewable Energy Buyback Scheme. From 1 July 2021, The Coordinator of Energy, working within Energy Policy WA, approves the terms and conditions of each retailer's buyback offer (an approved contract). In assessing whether the contracts, including the buyback rate, are 'fair and reasonable', the Coordinator of Energy considers:

- the wholesale cost of electricity for the retailer;
- line-loss reductions provided by distributed renewable energy;
- peak reductions provided by distributed renewable energy;
- capacity benefits provided by renewable energy; and
- the costs to retailers in running REBS.

The regulations do not oblige the Coordinator of Energy to consider any particular information with respect to determining what is 'fair and reasonable'. However, consistent with the national principles for feed-in tariff schemes, the Coordinator of Energy does consider the value to retailers of the energy received from customers. It also consider other factors, such as any additional costs incurred by retailers, where appropriate.

As at 1 July 2021 The DEBS rates were as follows:

- Peak (3pm to 9pm): 10 cents per kilowatt hour; and
- Other (all other times): 3 cents per kilowatt hour

For those customers still on REBS, The 2018-19 buyback rate for customers on the South West Interconnected System (SWIS) distribution network is 7.135 cents per kilowatt hour. In regional areas outside of the SWIS area, Horizon Power provides buyback rates that vary depending on where the system is installed. Horizon Power's website notes it is unable to connect any more renewable energy systems in some towns where the town has reached its technical limitations. In some cases, only installations with generation management (where output can be controlled) are able to connect.

ATTACHMENT 1: DRAFT DETERMINATION

The Tasmanian Economic Regulator –

(a) having conducted an investigation under Regulation 47B of the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013*; and

(b) having considered the principles in section 44H of the *Electricity Supply Industry Act 1995*,

makes the following Determination under section 44G(1) of the *Electricity Supply Industry Act 1995*.

Dated:

Joe Dimasi
TASMANIAN ECONOMIC REGULATOR

PART 1 – PRELIMINARY

Commencement date, effective date and expiry date

1. In accordance with Regulation 47E(3) of the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013*, this Determination takes effect on 1 July 2022 and remains in effect until 30 June 2025.

Interpretation

2. (a) Words have the same meaning as defined in this determination. Expressions not defined in this determination have the same meaning as they have in the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013* and the *Electricity Supply Industry Act 1995.*

(b) In this Determination –

"2022 Standing Offer Determination (Aurora Energy)" means the Aurora Energy Pty Ltd Price-Regulated Retail Service Price Determination issued by the Regulator as amended from time to time;

"AEMO" means the Australian Energy Market Operator ABN 94 072 010 327;

"annual standing offer price approval process" means the process outlined in any guideline issued by the Regulator relating to the approval of standing offer prices under the 2022 Standing Offer Determination (Aurora Energy);

"Aurora Energy" means Aurora Energy Pty Ltd ABN 85 082 464 622 and its successors;

"authorised retailer" has the same meaning as it has in the *Electricity Supply Industry Act 1995*;

"c/kWh" means cents per kWh;

"DLF" means distribution loss factor;

"feed-in tariff customer" has the same meaning as it has in the *Electricity Supply Industry Act 1995*;

"feed-in tariff rate" has the same meaning as it has in the *Electricity Supply Industry Act 1995*;

"kWh" means a kilowatt hour, which is the amount of energy used at a constant rate of one kilowatt for one hour (one kilowatt-hour is equivalent to 1 000 watt hours);

"MLF" means marginal loss factor;

"relevant period" means each of the periods from 1 July 2022 to 30 June 2023, from 1 July 2023 to 30 June 2024 and from 1 July 2024 to 30 June 2025 as relevant;

"Regulator" has the same meaning as it has in the *Electricity Supply Industry Act 1995*;

"wholesale electricity price" has the same meaning as it has in the 2022 Standing Offer Determination (Aurora Energy).

PART 2 – REGULATED FEED-IN TARIFF RATE

Method for determining a feed-in tariff rate in relation to a kilowatt hour

3. The feed-in tariff rate to be paid by an authorised retailer to a feed-in tariff customer during the term of this Determination is to be calculated in accordance with the method outlined in clause 4.

4. The minimum feed-in tariff for the relevant period is to be calculated in accordance with the following formula:

$$FiT_y = (WEP_y \times MLF_y \times DLF_y) + (AEMO_y \times DLF_y)$$

Where:

FiT_y is the regulated feed-in tariff rate in c/kWh to be paid to feed-in tariff customers.

y is the relevant period.

WEP_y is the wholesale electricity price calculated by the Regulator in accordance with the 2022 Standing Offer Determination (Aurora Energy), during the annual standing offer price approval process, expressed in c/kWh.

MLF_y means the load weighted average marginal loss factor at the regional reference node for Tasmania for the relevant period as approved by the Regulator during the annual standing offer price approval process.

DLF_y means the load weighted average distribution loss factor for Tasmania for the relevant period as approved by the Regulator during the annual standing offer price approval process.

$AEMO_y$ means the forecast charges, as billed by AEMO for market participation and ancillary services for each period that vary with the amount of wholesale electricity sold by authorised retailers, expressed in c/kWh. The Regulator will estimate AEMO charges for each period during the annual standing offer price approval process.

PART 3 – MISCELLANEOUS PROVISIONS

5. Any question arising from the interpretation of this Determination shall be decided by the Regulator.

6. This Determination is administered by the Regulator.

ATTACHMENT 2: INVESTIGATION NOTICE

Notice of Intention to Conduct a Regulated Feed-in Tariff Rate Determination Pricing Investigation

The *Electricity Supply Industry Act 1995* requires the Tasmanian Economic Regulator to make a feed-in tariff rate determination, which sets the minimum rate authorised electricity retailers are to pay standard feed-in tariff customers for energy exported to the electricity grid.

The determination will apply from 1 July 2022 to 30 June 2025. The investigation final report will be released, and the determination will be made, on or before 29 April 2022.

Before the Regulator makes a determination, the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013* require the Regulator to conduct a pricing investigation.

The objective of the pricing investigation is to gather information to assist the Regulator in making a determination.

The Regulator will publish a draft report and draft determination by 31 January 2022. Written submissions (preferably by email) on the draft report and draft determination can be made to the Regulator during a consultation period ending on 15 March 2022.

In accordance with the matters the Regulator is required to consider in determining the regulated feed-in tariff rate, submissions on the draft report and draft determination will be invited on issues including the following:

(a) the fair and reasonable value to authorised retailers of electricity supplied to the distribution network by feed-in tariff customers;

(b) the net financial benefit, to authorised retailers, of electricity supplied to the distribution network by feed-in tariff customers, having regard to the costs of authorised retailers, including:

- (i) the costs to authorised retailers of purchasing wholesale electricity; and
- (ii) other costs of authorised retailers in operating their retail electricity businesses;

(c) the other costs, or other benefits, that –

- (i) include those related to the distribution networks or transmission networks; and
- (ii) result, either directly or indirectly, from the supply of electricity to distribution networks by qualifying systems at premises of small customers;

(d) the COAG National Principles for Feed-in Tariff Arrangements, as those Principles apply from time to time;

(e) any arrangements of the Commonwealth, whether legislative or otherwise, in relation to the pricing of carbon emissions or other mechanisms to reduce the use of carbon-emitting fuels;

(f) the principle that the feed-in tariff rate specified in the determination should not have the effect that any customer would effectively be cross-subsidising any other customer; and

(g) approaches, methodologies, findings or recommendations, taken or made in other jurisdictions for determining fair and reasonable feed-in tariff rates.

The Regulator's draft report and draft determination will be available on the Economic Regulator's website: www.economicregulator.tas.gov.au.

For further information regarding this notice please contact:
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