Jemena Electricity Networks (Vic) Ltd

JEN 2022-23 Pricing Proposal

An appropriate citation for this paper is:

JEN 2022-23 pricing proposal

Our Ref: JEN 2022-23 pricing proposal

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Abbreviations

ACS	Alternative Control Services
AER	Australian Energy Regulator
CPI	Consumer Price Index
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Uses of System
JEN	Jemena Electricity Network Ltd (Vic)
LRMC	Long Run Marginal Cost
NEL	National Electricity Law
NER or the Rules	National Electricity Rules
NUOS	Network Use of System
OMR	Operating, maintenance and replacement
PFIT	Premium Solar Feed In Tariff
SCS	Standard Control Services
TSS	Tariff Structure Statement, as approved on 30 April 2021
TUOS	Transmission Use of System
WDV	Written down value

1. Introduction

1.1 Submission purpose

The National Electricity Rules (**NER or the Rules**) rule 6.18.2(a)(2) requires that Jemena Electricity Network Ltd (VIC) (**JEN**) submit an annual pricing proposal to the Australian Energy Regulator (**AER**) three months before the commencement of the second and each subsequent regulatory year of the regulatory control period. This submission is made in accordance with this requirement.

1.2 JEN's pricing

JEN has established efficient tariffs reflecting the drivers of its different customer classes. In accordance with the Rule requirements[1], JEN established its tariff classes and the tariff structures within its Tariff Structure Statement (**TSS**)[2] approved by the AER.[3]

This annual pricing proposal applies those approved tariff structures to 2022-23 tariffs and establishes tariff levels (prices) that meet the network pricing objective[4] and pricing principles.[5] Our proposed 2022-23 prices are based on the assumed $9.8M[6] banking of s-factor. If the AER does not approve Jemena's s-factor banking, then this will necessarily impact the 2022-23 prices as the $9.8M will be added back into the total 2022-23 revenue.

1.3 Submission structure and rule compliance

1.3.1 Submission structure

JEN has structured this submission to demonstrate compliance with each of the requirements of rule 6.18.2(b) of the NER and the AER's 2020 Final Decision.[7] The submission dedicates a section to each of the key areas of rule compliance:

- Section 2 – Tariff classes, tariffs and charging parameters
- Section 3 – Approach to setting tariffs
- Section 4 – Pricing proposal elements
- Section 5 – Designated pricing proposal, pass throughs and jurisdictional scheme recoveries
- Attachment 1 - Jemena 2022-23 proposed network tariff schedule
- Attachment 2 - Jemena 2022-23 alternative control services and public lighting charges
- Attachment 3 - Jemena – FINAL – 2022-23 annual SCS pricing model – 6 April 2022
- Attachment 4 - Jemena ACS-Public lighting Model
- Attachment 5 - Annual pricing confidentiality template
- Attachment 6 – Evidence of inputs in the financial tab

1 NER, cl 6.18.1A

2 AER, *Final Decision*, *Jemena distribution determination 2021-26*, *Revised Tariff Structure Statement April 2021 - Clean,* 30 April 2021.

3 AER, *Final Decision, Jemena distribution determination 2021-26, Tariff Structure Statement April 2021,* 30 April 2021.

4 NER, cl 6.18.5(a).

5 NER, cl 6.18.5(e)-(j).

6 Note we incorrectly reported this as $9,948,193 in our banking proposal. We consider the correct figure is $9,819,406 ($2022-23)

7 AER, *Final Decision, Jemena distribution determination 2021-26*, *Tariff Structure Statement April 2021,* 30 April 2021.

We have not made any changes to the draft ACS pricing model submitted to the AER on 25 February. As a result, the AER can consider our 25 February ACS pricing model as our formal 2022/23 submitted model.

1.3.2 Rule compliance

Table 1-1 sets out the specific rule requirement and where in this pricing proposal JEN has demonstrated compliance.

Table 1-1: Rule compliance submission references

Topic	Relevant rules	Submission reference
Pricing Proposal elements	6.18.2(b)(2) of the NER requires that the pricing proposal set out the proposed tariffs for each tariff class;	Section 2, Attachment 1(SCS) and Attachment 3
	6.18.2(b)(3) of the NER requires that the pricing proposal set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates;	Section 2, Attachment 1 (SCS) and Attachment 2 (ACS)
	6.18.2(b)(4) of the NER requires that the pricing proposal set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year;	Attachment 3
	6.18.2(b)(5) of the NER requires that the pricing proposal set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur;	Section 5
	6.18.2(b)(6) of the NER requires that the pricing proposal set out how designated pricing proposal charges are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year;	Attachment 3 and Section 4
	6.18.2(b)(6A) of the NER requires that the pricing proposal set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;	Attachment 3
	6.18.2(b)(6B) of the NER requires that the pricing proposal describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria;	Section 5
	6.18.2(b)(7) of the NER requires that the pricing proposal demonstrates compliance with the Rules and any applicable distribution determination;	All
	6.18.2(b)(7A) of the NER requires that the pricing proposal demonstrates how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them;	Section 4
	6.18.2(b)(8) of the NER requires that the pricing proposal describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the Rules and any applicable distribution determination.	Sections 3 and 4
	6.18.2(e) of the NER requires that where the Distribution Network Service Provider submits an annual pricing proposal, the revised indicative pricing schedule referred to in paragraph (d) must also set out, for each relevant	Section 4, Attachment 3

Topic	Relevant rules	Submission reference
	tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.	
Pricing principles	6.18.5(a) of the NER describes the network pricing objective, which is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer	Section 3
	6.18.5(e) of the NER describes that the revenue for each tariff class is expected to be recovered should lie on or between: (1) an upper bound representing the stand alone cost of serving the customers who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those customers.	Section 3
	6.18.5(f) of the NER describes that each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) the costs and benefits associated with calculating, implementing and applying that method as proposed; (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and (3) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.	Section 3
	6.18.5 (g) of the NER requires the revenue expected to be recovered from each tariff must: (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	Section 3
	6.18.5(h) of the NER requires a Distribution Network Service Provider to consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);	Section 3

Topic	Relevant rules	Submission reference
	(2) the extent to which retail customers can choose the tariff to which they are assigned; and (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	
	6.18.5(j) of the NER requires tariffs to comply with the Rules and all applicable regulatory instruments.	Section 4
Side constraint	The final decision price control mechanism requires a side constraint to apply to each tariff class related to the provision of standard control services.[8] The expected weighted average revenue to be raised from a tariff class for a regulatory year must not exceed the corresponding expected weighted average revenue for the preceding regulatory year by more than the permissible percentage provided in the following formula $\frac{(\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_t^{ij})}{(\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_t^{ij})} \leq (1+\Delta CPI_t) \times (1-X_t) \times (1+2\%) + I_t^i + B_t^i + C_t^i$	Attachment 3
	6.18.6(d) of the NER states that in deciding whether the permissible percentage has been exceeded in a particular regulatory year, the following are to be disregarded: (1) the recovery of revenue to accommodate a variation to the distribution determination under rule 6.6 or 6.13; (2) the recovery of revenue to accommodate pass through of designated pricing proposal charges to customers; (3) the recovery of revenue to accommodate pass through of jurisdictional scheme amounts for approved jurisdictional schemes; (4) the recovery of revenue to accommodate any increase in the Distribution Network Service Provider's annual revenue requirement by virtue of an application of a formula referred to in clause 6.5.2(l).	Attachment 3
Designated Pricing Proposal Charges (includes recovery for transmission charges, inter DB charges and avoided transmission payments)	6.18.7(a) of the NER requires a pricing proposal to provide for tariffs designed to pass on to customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider.	Attachments 1 and 3
	6.18.7(b) of the NER determines that the amount to be passed on to customers for a particular *regulatory year* must not exceed the estimated amount of the *designated pricing proposal charges* adjusted for over or under recovery in accordance with paragraph (c)	Attachment 3
	6.18.7(c) of the NER requires the over and under recovery amount to be calculated in a way that: (1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider; (2) ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the designated pricing proposal charges it incurs; and. (3) adjusts for an appropriate cost of capital that is consistent with the rate of return used in the relevant distribution determination for the relevant regulatory year	Attachment 3

[8] AER, *Final Decision, Jemena distribution determination 2021 to 2026*, *Attachment 14, Control mechanisms,* Figure 14, April 2021.

Topic	Relevant rules	Submission reference
Jurisdictional scheme	6.18.7A(a) of the NER requires a pricing proposal to provide for tariffs designed to pass on to customers a Distribution Network Service Provider’s jurisdictional scheme amounts for approved jurisdictional schemes.	Attachments 1 and 3
	6.18.7A(b) of the NER requires the amount to be passed on to customers for a particular regulatory year (year t) must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes for year t adjusted for over or under recovery in accordance with paragraph 6.18.7(c).	Attachment 3

1.3.3 Submission values and terminology

This submission employs the following standards:

- All cost estimates and revenues are expressed in $2022-23 unless otherwise stated.
- All prices are expressed in $2022-23.
- The term ‘customer’ should be interpreted as an end user of electricity rather than an electricity retailer.

2. Tariff classes and tariffs

In this section JEN sets out its tariff classes and tariffs for 2022-23, which are those outlined in our TSS.

2.1 Distribution use of system services

The tariff classes for distribution uses of system (**DUOS**) standard control services are as set out in our TSS. Table 2-1 sets out JEN's 2022-23 DUOS tariff classes and the tariffs that are categorised within each of these.

Table 2-1: Tariff classes for standard control DUOS services

Tariff class	Relevant tariffs[9]	Class definition
Residential	A100 / F100[10] single rate A120 / F120 time of use A10D / F10D single rate – demand A180 off peak heating only (dedicated circuit)	Only available to residential customers.
Small business[11]	A200 / F200 single rate A210 / F210 time of use weekdays A20D / F20D single rate – demand A230 / F230 time of use weekdays – demand A23N / F23N time of use (demand opt out) A270 / F270 time of use extended – Demand A290 unmetered supply	Available to network customers (embedded or non-embedded) with annual consumption < 0.4 GWh AND maximum demand < 120 kVA. Customers with maximum demand greater than 120 kVA but consuming < 160 MWh pa are eligible for the demand 'opt out' A23N tariff. This may trigger a capital contribution recalculation.
Large business - low voltage	A300 / F300 LV <=0.8 GWh A30E LV_{EN} annual consumption <=0.8 GWh A30C / F30C LV <=0.8 GWh cost reflective A320 LV 0.8+ - 2.2 GWh A32E LVEN 0.8+ - 2.2 GWh A32C LV 0.8+ - 2.2 GWh cost reflective A340 LV 2.2+ - 6.0 GWh A34E LVEN 2.2+ GWh A34C LV 2.2+ - 6.0 GWh cost reflective A34M LVMS 2.2+ - 6.0 GWh A34T LVMS 2.2+ - 6.0 GWh cost reflective A370 LV 6.0+ GWh A37C LV 6.0+ GWh cost reflective A37M LVMS 6.0+ GWh A37T LVMS 6.0+ GWh cost reflective	Only available to embedded network customers OR non-embedded network customers: with annual consumption >= 0.4 GWh <u>or</u> maximum demand >= 120 kVA.

9 Some of these tariffs are closed to new entrants as shown in Attachment 1.

10 A tariff code starting with the letter "F" indicates that the tariff attracts the premium feed-in tariff rebate but are otherwise the same as the equivalent "A" tariff. These are closed to new entrants.

11 Small business includes medium business.

Tariff class	Relevant tariffs[9]	Class definition
Large business - high voltage	A400 HV A40E HV_{EN} A40C HV cost reflective A40R HV_{RF} A40T HV_{RF} cost reflective A480 HV - annual consumption >= 55 GWh A48C HV - annual consumption >= 55 GWh cost reflective	Only available to customers taking High Voltage supply (nominal voltage >= 1000 volts AND <= 22,000 volts)
Large business - sub-transmission	A500 sub-transmission A50C sub-transmission cost reflective A50A sub-transmission MA A50T sub-transmission MA cost reflective A50E sub-transmission EG A50X sub-transmission EG cost reflective A50M sub-transmission – multiple connection	Only available to customers taking supply form a nominal voltage > 22,000 volts

2.1.1 Setting efficient tariff classes

JEN's TSS and TSS explanatory document[12] sets out how we established the above tariff classes and demonstrated these were efficient. Our 2022-23 prices apply to the tariff structures and tariff classes shown in Table 2-1.

2.2 Alternative control services (ACS)

JEN has a single alternative control services tariff class as set out in our TSS. Within this tariff class, there are multiple user-requested services, each with their own associated price or unit rates that are proposed by us, but approved by the AER. The method for determining prices for these services takes two different forms as described in Table 2-2.

Table 2-2: Alternative control services tariff classes

Service	Relevant services	Definition
Fee based services	Includes: • Ancillary Network Services for which the AER has applied a cap on prices, for example, services such as basic connections, de-energisations, re-energisations • Metering services for 'small customers' (Type 5, 6 and AMI meters), Type 7 metering and other auxiliary metering services provided on a customer-requested basis • The operation, maintenance and replacement (OM&R) services for public lighting, which the AER has applied a cap on the price per lighting type. This also includes pricing for the written down value (**WDV**) and avoided cost for use when public lighting customers seek to change their old lighting stock to more efficient light types before the end of their economic life (section 3.3.3).	Services for which the AER has applied a cap on the price per service.

12 Jemena, *Revised Regulatory Proposal – 2021-26 – Att 12-02 Tariff Structure Statement Explanatory document*, December 2020.

Service	Relevant services	Definition
Quoted services	Services for which the AER has placed a cap on the applicable labour rates (inclusive of labour on-costs and overheads). Prices for quoted services are based on quantities of labour plus materials and contractor services.	Services for which the AER has placed a cap on the applicable labour rates.[13]

13 Cap does not apply to materials and contracts.

3. Approach to setting tariffs

3.1 Stand alone and avoidable cost for each tariff class

Rule 6.18.5(e) requires that revenues from each tariff class for direct control distribution services must lie between the economically efficient bounds of stand alone and avoidable costs. The purpose of applying stand alone and avoidable cost bounds on expected tariff class revenues is to ensure that, for each tariff class, the Distribution Network Service Provider (**DNSP**) is not pricing outside the bounds defined by economic efficiency. These stand alone and avoidable cost bounds are the highest and lowest theoretical prices that a distributor could charge a customer class without imposing costs on other classes. That is, pricing outside these efficient bounds implies cross subsidisation between customer classes if the business is recovering its costs.

The avoidable cost of serving a group of customers is the reduction in cost that could be achieved if those customers were no longer served, i.e. the reduction in cost associated with a decrease in output that was previously provided to that class of customer. The stand alone cost of serving a group of customers is the total cost required to serve those customers alone, i.e. if JEN were to build the network anew, removing all other customers from the network

Our TSS outlines JEN's approach to estimating stand alone and avoidable costs for standard control services (**SCS**).

Table 3-1 presents the standalone & avoidable estimates and the 2022-23 expected revenue results for each tariff class. It demonstrates that the expected revenue falls between avoidable and standalone costs for each tariff class.

Table 3–1: Stand alone & avoidable cost estimates compared to expected revenues ($M, 2022-23)

Tariff class	Avoidable cost	Expected revenue	Stand alone cost estimate
Residential	$14.86	$129.39	$1,133.73
Small business	$5.28	$51.95	$1,283.99
Large business - low voltage	$9.12	$64.66	$1,447.67
Large business - high voltage	$2.79	$21.79	$482.58
Large business - sub-transmission	$0.64	$2.68	$160.48

Our ACS are priced at cost as these services are incremental to the distribution business. The initial costing was reviewed and approved by the AER as part of the 2021-26 Electricity Distribution Price Review[14] with annual updates to occur in accordance with the price control mechanism.[15] .

[14] AER, Final Decision, Jemena distribution determination 2021 to 2026, Attachment 16, Alternative Control Services, April 2021.

[15] AER, Final Decision, Jemena distribution determination 2021 to 2026, Attachment 14, Control Mechanisms, April 2021.

3.2 Long run marginal cost

Rule 6.18.5(f) requires that each tariff be based on the long run marginal cost (**LRMC**) of providing the service to which it relates to the retail customers assigned to that tariff.

Table 3-2 sets out the LRMC estimates JEN has developed, using the methodology described in our TSS and updated for CPI.

Table 3–2: JEN LRMC estimates

Tariff class	Unit	LRMC
Residential	$/kW	53.41
Small business	$/kW	37.10
Large business - low voltage	$/kVA	32.06
Large business - high voltage	$/kVA	20.10
Large business – sub-transmission	$/kVA	0.21

3.2.1 Application of LRMC

Rule 6.18.5(f) requires our tariffs be based on LRMC. Our LRMC has been calculated based on our cost driver, which is capacity (kW or kVA). All tariff classes have at least one tariff with a demand tariff component. This includes an opt-in tariff with a demand tariff component for small customers.

The demand tariff component is based on the LRMC levels. As our LRMC levels are relatively low compare to historical levels we have to collect a higher proportion of residual revenue in a way that minimises price distortions.[16] This might normally lead to collecting the full residual revenue from fixed charges. However, consistent with our TSS, we recognise the disproportionate impact increasing fixed charges has on smaller customers and continue our balanced approach to increase fixed charges by $6 above the average price change. As this approach does not recover all the necessary residual revenue, we will continue to recover some of this from the demand and usage charge components.

Additionally, we have set the prices of our residential time of use tariff so that a typical customer's network bill is the same whether on the demand tariff or time of use tariff. As set out in our TSS, we have set both of these at approximately a 2% discount to the single rate tariff (see Table 3-3). The time of use tariff will still, therefore, be set to best reflect the LRMC values and revenue we would obtain had a demand charge applied. This provides a link between the LRMC levels and our tariff levels (or prices) for our other residential tariffs.

Table 3–3: Discount applied to cost reflective residential tariffs

Tariff Code	Tariff Name	Peak (kWh)	Off Peak (kWh)	Demand (kW)	DUOS bill ($)	% Discount to A100
A100	Residential single rate	4,265			$384	
A120	Residential time of use	1,749	2,516		$375	2.5%
A10D	Residential demand	4,265		3	$375	

Similarly, our business customer demand tariff components include some residual revenue recovery to ensure we minimise year-on-year price (or period on period) volatility driven by updated LRMC calculations. More information on how we set prices can be found in our TSS.

16 Rule 6.18.5(g)(3).

3.3 Remaining pricing principles in the Rules

As required by the Rules, JEN has had regard to a number of other relevant pricing principles when determining our 2022-23 tariff levels.

3.3.1 Recovering efficient costs

Rule 6.18.5(g) requires that we only recover our efficient costs and that tariffs reflect the total efficient costs of serving retail customers assigned to each tariff. It also requires that allowed revenue is recovered in a way that seeks to minimise distortions to efficient price signals.

Attachment 3 demonstrates that our expected revenue falls within our allowance (total allowed revenue or TAR). Section 3.2.1 details our approach to recovering residual revenue to minimise price distortions.

Calculating our expected revenue requires we forecast customer numbers, consumption and demand for:

- 1 July 2021 to 30 June 2022 (t-1) - this forecast impacts the unders and overs account via the t-1 under or over recovery.
- 2022-23 - this forecast impacts the expected 2022-23 revenue, and therefore, 2022-23 price levels.

Our 2022-23 demand forecasting methodology combines:

- Projections based on weather normalised historical data.
- Customer number and consumption growth rates established as part of our 2021-26 regulatory proposal.[17]
- Adjustments based on up-do date large business customer connection information and to reflect pandemic recovery.

We detail this approach further for each of customer numbers, our volume forecast and demand forecasts below.

3.3.1.1 Customer number forecast

Our approach for the customer numbers forecast is to:

- Extract the most recent customer numbers that are assigned to each of Jemena Network's tariffs from the SAP billing system.
- Update our customer numbers forecast for year t-1 (1 July 21 to 30 Jun 22) by replacing the first six months of forecast with actuals. These also reflect the new tariff structures as at 1 July 2021 and observed opt-in/opt-out movements.
- Project forward customer numbers for year t by applying the forecasted customer number growth rates provided by ACIL Allen for our 2021-26 regulatory proposal (see table 3-4) to the t-1 estimates.
- Adjust our residential tariff segment based on known movements to cost-reflective tariffs (to the A120 from the A100) that occurred in t-1. We have also forecast additional movement in FY23 expected to occur from the increased discount.
- Adjust our high voltage large business tariff segment based on our expected new connections.[18] Customer numbers adjusted to reflect the actual dates we expect them to connect and the number of full year equivalent customers added.

[17] Forecast growth rates provided by ACIL Allen. These have an assumed impact of solar penetration built into them.

[18] These additional new sites are also taken into consideration when forecasting energy consumption and demand via the approach to forecast consumption per demand and multiply these by the forecast customer numbers on each tariff.

3.3.1.2 Volume forecast

Our approach for the volume (consumption) forecast differs slightly depending on the tariff we are forecasting. For tariffs with large number of customers we use a consumption per customer approach. For tariffs with smaller customer numbers, it is more appropriate to consider those customers individually.

Our approach is to:

- Estimate t-1 consumption:
  - Extract the last 5 years of actual consumption by tariff component for each tariff class from the SAP billing system[19].
  - Weather normalise this historical data by applying a methodology that considers movements of heating degree days and cooling degree days from historical averages.
  - Make adjustments to historical data to align with new tariff structures as at 1 July 2021.
  - Using the first six months of actuals and a forecast of the last six months of forecast consumption. The last 6 months' forecast consumption is calculated using the 5 year averages of actual weather normalised consumption.
- Forecast consumption for each tariff component for year t:
  - For residential and small business customers: apply adjusted growth rates provided by ACIL Allen for our 2021-26 regulatory proposal (see table 3-4) to the t-1 consumption (or consumption per customer) estimates.
  - These growth rates are adjusted to consider an up-to-date view of the pandemic impact/recovery.
  - For our large business tariff customers, obtain consumption per kVA for year t-1 and multiply this by forecasted customer number in year t.

3.3.1.3 Demand (capacity) forecast

Our approach for the demand forecast is to:

- Estimate t-1 demand:
  - Extract most recent actual capacity (demand measured in kW or kVA as appropriate for the tariff) that are assigned to each of our tariffs from the SAP billing system (tariff component capacity divided by tariff customer numbers).
  - Make adjustments to historical data to align with new tariff structures as at 1 July 2021.
  - Update t-1 demand per customer by using the first six months of actual capacity per customer and multiplying it by the updated t-1 customer number estimate.
- Forecast demand for each tariff component for year t:
  - Multiply the updated t-1 tariff component capacity per customer by the year t customer numbers forecast calculated above.
  - We made adjustments to the demand of our HV tariffs to take into account the different timing that those customers are assumed to connect to the network.

[19] For consumption per customer we divide consumption by tariff customer numbers.

Table 3–4: Growth Rates

Customer Segment	Customer Number	Consumption
Residential	1.5%	0.9%
Small Business	0.8%	0.4%
Large Business – LV	1.4%	0.5%
Large Business – HV	6.6%	10%
Large Business – Sub-transmission[20]	0%	0.9%

3.3.2 Impact on customers

JEN has considered the impact on retail customers (Rule 6.18.5(h)) of changes in tariffs between 2021-22 and 2023-24.

We observed potential bill volatility arises primarily arises from a number of elements overlayed upon the x-factor and CPI impacts of the revenue cap:

- A $14.7M s-factor entitlement (made up of banking last year's (2021-22) $4.8M s-factor and the $9.8M incentive payment for 2022-23[21]) putting upward pressure on 2022-23 prices
- A forecast -$2.2M s-factor incentive payment for 2023-24 putting downward pressure on 2023-24 prices.
- Significant new large business connections in 2023 and 2024 that impact future demand forecasts and put downward pressure on 2023-24 prices.

The net impact of these movements would be a $8 increase in residential customers network bills in 2022-23 followed by a $16 decrease in 2023-24 (see Figure 3-1).

We have also considered retail outcomes for customers, noting that the ESC is engaging on an increase to the Victorian Default Offer from 1 July 2022, which would increase a typical residential customer's bill by $19 or $73 for a small business. This was driven by recent wholesale market price increases.

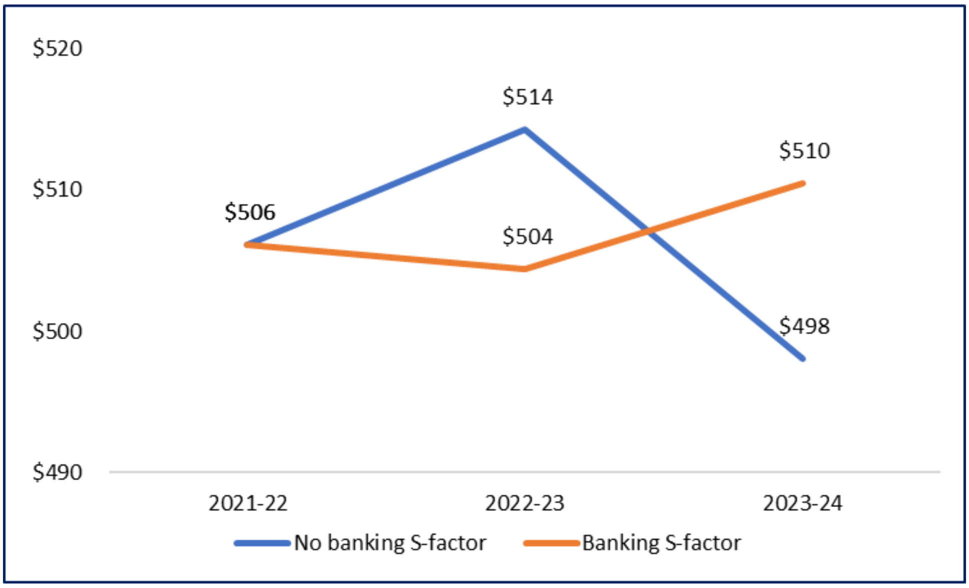
20 We have varied from the Acil Allen growth rate for sub-transmission to reflect specific customer circumstances during the pandemic.

21 Note we incorrectly reported this as $9,948,193 in our banking proposal. We consider the correct figure is $9,819,406 ($2022-23)

3.3.2.1 Banking S-factor

Given the network bill volatility, we have proposed to bank Jemena's 2022-23 s-factor entitlement, which delays the recovery of $9.8M from 2022-23 to 2023-24)[22]. For residential customers, banking S-factor smooths bills across 2021-22 to 2023-24 as seen in Figure 3-1.

Figure 3–1: Typical residential customer network bill ($, nominal, NUOS and AMI)



3.3.2.1 Pass through amounts

JEN has also considered the impact on different market segments of how we recover our pass through amounts (jurisdictional and transmission use of system (**TUOS**) charges), which we began adjusting in 2020 tariffs. We consider that we can continue to improve how these pass throughs are allocated to the different market segments to mitigate the volatility associated with these costs. We discuss this further in section 5.2.2

In addition we note that the final customer bill impacts are subject to the actions undertaken by the retailers. For example, retailers may or may not choose to pass through network price changes in full.

3.3.2.2 Typical customer bill impacts

Table 3-5 shows the proposed typical customer Network Use of System (**NUOS**) and AMI bill impacts for each market segment from 2021-22 to 2022-23. Business has greater 2022-23 decreases driven by the TUOS reductions.

22 This is based on the assumption that the AER has approved Jemena's s-factor banking – Jemena email to the AER, 16 March 2022.

Table 3-5: Proposed typical customer bill impacts (including AMI where applicable) ($ nominal)

Market Segment	Bill for 2021-22	Bill for 2022-23	Bill change from 2021-22 to 2022-23 ($)	NUOS % change
Residential	$506	$504	-$2	-0.3%
Small Business	$1,619	$1,608	-$10	-0.6%
Large Business - low voltage	$39,049	$36,415	-$2,634	-6.7%

3.3.3 JEN ACS model and written down value & avoided cost

Our ACS prices for 2022-23 escalate current prices by inflation. This is included in the draft ACS pricing model submitted to the AER on 25 February. We have not made any changes to this model and as a result, the AER can consider our 25 February ACS pricing model as our final 2022-23 submitted model. Due to rounding, there may be some discrepancies between the historical approved ACS prices and those presented in the ACS pricing model.

In addition to the draft ACS pricing model, and consistent with our historical approach, we have escalated the WDV and avoided cost charges of our public lighting prices by inflation (refer Attachment 4). The WDV and avoided cost charges are part of the public lighting prices is found in Attachment 2.

4. Pricing proposal elements

4.1 Price variation elements

Rule 6.18.2(b)(8) requires we describe the nature and extent of change from the previous regulatory year.

The variables that influence the SCS DUOS prices are:

- Approved revenue path for the regulatory year (X-factor)[23] updated for the cost of debt Annual percentage change in the CPI
- F-factor incentive scheme amount
- STPIS (S-factor)
- Demand management incentive scheme (**DMIS**)
- Demand management innovation allowance (**DMIA**)
- Sum of approved cost pass through amounts with respect to the regulatory year (C term)
- Under or over recovery of actual revenue collected through DUOS charges in prior years plus recovery of license fee charges, less previous year deliberate under-recovery (B term).

Table 4-1 shows the price variations for each variable in JEN's 2022-23 initial pricing proposal.

Table 4–1: JEN annual SCS price variation elements

Price variation element	Percentage / $
CPI	3.5%
X-factor	0.76%
F-factor	$49,500
S-factor	$4,879,206 (an additional $9,819,406 proposed to be banked until 2023-24 as described in section 3.3.2)
DMIS	$0
DMIA	$580,405
I (s-factor, DMIS and DMIA)	$4,348,301
C	$0
B	-$2,389,208

4.2 Comparison to revised proposal indicative prices

6.18.2(b)(7A) requires we demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them.

23 AER, *Final Decision, Jemena distribution determination 2021-26*, *Overview,* 30 April 2021.

We provided updated indicative 2022-23 prices in our 2021-22 pricing proposal.[24] At a NUOS level, a few of our 2022-23 proposed price levels have a material difference of over 10% from our indicative price levels.[25] This is due to:

- **Residential ToU (A120) peak consumption tariff component** - Our previously calculated indicative prices incorrectly used the lower A100 usage price for the TUoS and jurisdictional peak price (A120). This incorrectly under-forecast the NUOS indicative price when summed. The peak price is also impacted by the issue discussed below in relation to the off peak price
- **Residential ToU (A120) off peak consumption tariff component** - Driven by our updated demand forecast, which includes a number of new customers on the A120. This, as well as trends we are observing shifts the balance between peak and off peak consumption more to off-peak. We then need to ensure prices align to the proposed discount for the A120 time of use over the A100 single rate tariff.
- **Large business annual demand tariff (A50X)** - To maintain consistency with AEMO's revised pricing methodology (from existing 10 Maximum Demand to 365 day methodology), we are not proposing to recover TUOS from the summer demand incentive component (SDIC).[26] Instead, this revenue is being recovered from annual demand. This results in a TUOS SDIC price set to zero and a relative increase to our annual demand TUOS price (which feeds into the NUOS price) that was not contemplated in our previous indicative prices. Whilst this impacts all large business tariffs to some extent, only the A50X is above the 10% threshold. For the avoidance of doubt, this just shifts the tariff component where the revenue is collected from, and does not change the TUOS revenue that would be collected from large business customers.

4.3 Revised indicative prices

We set out indicative price levels for each of the remaining regulatory years of the regulatory control period in the "Indicative prices" tab of Attachment 3. These have been updated so as to take into account this 2022-23 pricing proposal.

[24] Jemena – 2021-22 *Pricing Proposal* – Attachment 5 2022-23 to 2025-26 indicative prices - June 2021.

[25] We have adjusted the materiality threshold in the General tab of the pricing model to a 10 per cent trigger to be consistent with previous year requirements.

[26] AEMO provided final AER approved prices based on the 365 day method on 31 March 2022. The AER approved the shift in methodology on 31 March 2022. We do not consider it appropriate to recover TUOS from a summer peak period when the costs we incur are calculated based on demand throughout the year.

5. Designated pricing proposal, pass throughs and jurisdictional scheme outcomes

5.1 Tariff variation for pass throughs

5.1.1 Rule requirements

Rule 6.18.2(b)(5) requires that a DNSP's pricing proposal must:

> *set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur*

5.1.2 Potential tariff variation for pass throughs

5.1.2.1 Possible pass through events

Chapter 10 of the Rules specifies that the following pass through events are applicable to all distribution determinations:

- regulatory change event
- a service standard event
- a tax change event
- a terrorism event.

In addition to the pass through events and provisions set out in the Rule, the AER has determined the following pass through events are also applicable to JEN:[27]

- an insurance cap event
- an insurer credit risk event
- a natural disaster event
- a terrorism event
- a retailer insolvency event.

5.2 Designated pricing proposal costs

5.2.1 Rule requirements

Rule 6.18.2(b)(6) requires that a DNSP's pricing proposal must:

> *set out how designated pricing proposal charges are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year*

[27] AER, *Final Decision, Jemena distribution determination 2021-2026, Attachment 15, Pass through events*, April 2021.

5.2.2 Designated pricing proposal charges

JEN has set out a schedule of its proposed Designated Pricing Proposal Charges (incorporating TUOS tariffs) in Attachment 1 of this document. These tariffs are set to recover JEN's required transmission revenues as calculated in accordance with the mechanism specified in the AER's final determination[28] and shown in Attachment 3.

As shown in Table 5-1, the expected TUOS revenue decrease from 2021-22 to 2022-23 is 17 per cent.

Table 5–1: Estimated TUOS revenue increase ($M, Nominal)

	2021-22	2022-23
Grid Fee Forecast	$72.9	$72.7
Under recovery from previous year	$12.2	-$2.2
Actual/allowed revenue current year (grid fees plus under recovery)	$85.1	$70.5
Estimated revenue collected	$85.1	$70.5
		-17%

Attachment 3 provides the full unders and overs account for TUOS.

The volatility of transmission pass through disproportionally impacts the large business customer bills due to larger portion of their bills made up of transmission costs. Our long-term goal is to better align TUOS and DUOS allocations as set out in our TSS. Our TSS strategy indicated we would seek to target all TUOS decreases towards large business customers when TUOS price decreases occur.

For 2022-23, we have increased residential TUOS allocation from 22 per cent to 25 per cent of total TUOS, while still providing a $6 annual decrease to residential TUOS bills.

5.3 Jurisdictional scheme recoveries

5.3.1 Rule requirements

Rules 6.18.2(b)(6A) and 6.18.2(b)(6B) require that a DNSP's pricing proposal must:

> *(6A) set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts; and*
>
> *(6B) describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria*

5.3.2 Relevant jurisdictional schemes

There are two relevant jurisdictional schemes:

- Feed-in tariffs

[28] AER, *Final Decision, Jemena distribution determination 2021-26 Attachment 14, Control mechanisms,* April 2021.

- ESV levy.

Both the Premium Solar Feed in Tariff (**PFIT**) and the Transitional Feed-in Tariff (**TFIT**) are now closed to new entrants.

PFIT tariffs have been closed to new entrants from 1 January 2012 as per the Minister for Energy and Resources announcement on 1 September 2011. Eligible properties with an effective PFIT contract will continue to receive this rate until 2024.

On 19 March 2021, the AER determined that the treatment of ESV levy's established by section 8 of the Electricity Safety Act 1998 (Vic) (ESA) would become a jurisdictional scheme.

5.3.3 Jurisdictional scheme tariffs

JEN has set out a schedule of its proposed tariffs to recover costs incurred through relevant jurisdiction schemes in Attachment 1. These tariffs are set to recover JEN's required jurisdictional scheme revenues as calculated in accordance with the mechanism specified in the AER's Final Decision[29] and reflected in Attachment 3. We propose to recover jurisdictional scheme revenues from customer segments in the same proportion as we have historically.

[29] AER, *Final Decision, Jemena distribution determination 2021-26 Attachment 14, Control mechanisms,* April 2021.