AEMO TUOS Pricing Methodology Issues Paper

September 2020

TUOS pricing for a changing transmission network

An Issues Paper to help inform AEMO develop Victorian TUOS pricing approach in a changing network environment

Important notice

PURPOSE

AEMO publishes this document to inform AEMO in the development of AEMO's revised *pricing methodology*.

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Contents

1. Need for Consultation

AEMO as the TNSP for the Victorian transmission system recovers the cost of the *prescribed transmission services* (except *prescribed exit services* and *prescribed entry services* which are recovered by AusNet Services) from *Transmission Network Users* in accordance with its *pricing methodology* which is approved by the AER in accordance with Chapter 6A of the *National Electricity Rules* (NER). The current AEMO *pricing methodology* is available on the AEMO website[1] and entitled "Approved amended Pricing Methodology for Prescribed Shared Transmission Services for 1 July 2014 to 30 June 2019". The validity of the methodology has been extended under an enforceable undertaking by AEMO initially to 30 June 2021 (available on the AEMO website[2]) to allow AEMO to conduct further analysis and consult on emerging developments in the NEM and their effect on network pricing and investment. A further extension to 30 June 2022 is also being discussed with the AER and the updated enforceable undertaking will be published on AEMO's website when formalised.

This consultation issues paper looks at the changing nature of the power system and how that may affect the transmission pricing methodology that is currently used by AEMO. The paper presents issues, identifies options to deal with the issues and explains AEMO's initial preference for dealing with each of the issues.

2. Background

There are major changes occurring in the Australian power systems being brought about by forces such as climate change and new technology. These are driving changes in the type and location of investments as well as power flows. The particular issues which may require changes to the transmission pricing methodology include:

- With a large and growing amount of distributed energy generation some transmission connection points in the Victorian power system now have reverse flows into the transmission system. How should reverse flows be treated when calculating transmission prices?
- Batteries and other energy storage devices are becoming an increasingly important part of the overall electricity delivery chain. Batteries in particular have experienced a remarkable drop in costs in the past few years and their penetration, in both grid connected and behind the meter applications, is expected to increase substantially, This not only raises the question as to whether they should pay for use of the transmission system but how should losses be accounted for and what adjustments should be made for "hybrid" type loads[3]?

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[1] https://www.aemo.com.au/-/media/files/pdf/approved-amended-pricing-methodology--1-july-2014-to-30-june-2019.pdf

[2] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Fees/2019/AEMO---NER-s59-Undertaking---12-June-2019_0.pdf

[3] In this context, a "hybrid" load is a load with combination of generation (e.g. solar panels) and energy storage (e.g. batteries).

- When determining the locational price component of the annual Transmission Use of System (TUOS) charges, AEMO applies a methodology that takes the average of the transmission customer's half-hourly maximum demand recorded at a connection point on the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 over the course of 365 days (MD10). This has historically been consistent with the requirement in the NER that locational pricing "must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated".[4] However, in recent times, it has not been peak demand that has been driving current investments. Is the MD10 methodology still appropriate in the current environment?

3. Reverse Flows at Transmission Connection Points

3.1 Issues Raised by Reverse Flows

The current approach to transmission pricing was developed in the mid 1990s and has been in place since the start of the NEM in 1998. The transmission system was at that stage much simpler in its structure in that there were large generators which were generally located at their fuel sources and this generation then flowed through the transmission system to the major load centres. The generators injected power into the transmission system, there were transmission losses associated with transmitting the power and then the loads extracted the power. This meant that Transmission Connection Points (TCP) were always loads. A decision was made at the beginning of the NEM about who should pay for transmission services and it was decided that loads (*Transmission Customers*) should pay.

The transmission pricing regime is designed around locational and non-locational charges for use of a transmission network for the conveyance of electricity. If a decision had been made to charge generators, then injections into the transmission network would also be charged but it was decided that generators would not pay and therefore injections are not subject to a charge.

The current power system now has TCPs ("load points") that do not always behave as loads and so the question arises what happens when loads turn into generators (i.e. there is reverse flow at the TCP) as they do now with distributed energy generation and in some cases with storage devices?

To illustrate the issue of loads having increasing reverse flows, Table A shows the percentage of time during the 12 month period between July and June that certain connection points measured reverse flows during 2017-2018 and 2018-2019.

Terminal station	**Percentage of time during the year when reverse flows occurred**	
	2017-18	**2018-19**
Kerang (KGTS)	0%	27.5%

[4] See clause 6A.23.4(b) of the NER.

Terang (TGTS)	1.0%	18.9%
Horsham (HOTS)	5.4%	16.5%
Wemen (WETS)	0%	14.5%
Redcliffs (RCTS)	0%	3.7%

Table A: Percentage of Time When Reverse Flow Occurs[5]

With the current penetration of distributed renewable energy resources and battery installations, it is expected that within 10 years the number of TCPs with significant reverse flows will increase and this issue is likely to grow in its importance and should be considered in accordance with the principles required under the NER.

3.1.1 Impacts on Non-locational and Common Services Charges

Non-locational and Common Services costs are currently recovered using energy or Contract Agreed Maximum Demand (CAMD) methodology with the constraint that the median load factor is financially indifferent to an energy or maximum demand price. As the energy and maximum demand prices are dependent on each other because of this constraint, if the method of calculating energy is changed so too will the maximum demand price change.

Consider a simple example of a system, as shown in Figure 1, with three TCPs all of which are on energy tariffs because they do not have a CAMD and one TCP has reverse flow. Table B shows the outcome with all other variables held constant and the only difference is the treatment of the reverse flow. The amount to be recovered by non-locational service charges or NLC_t is $35m.

Energy vs Contract Agreed Maximum Demand

Energy is the measured electrical flow over the connection point over the course of the year (usually measured in MWh or GWh). The TUOS price associated with this calculation method is often referred to as an energy based price

Contract Agreed Maximum Demand (or CAMD) is the maximum electrical power transfer capability at the connection point and agreed by a Network User and AEMO in a Use of System Agreement (usually measured in MW). The TUOS priced associated with this calculation is usually referred as a capacity based price.

[5] 2019 Victorian Annual Planning Report page 30 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2019/victorian-annual-planning-report-2019.pdf?la=en&hash=0AF8BABAA9315FB0A2D9B82E42D37C0C

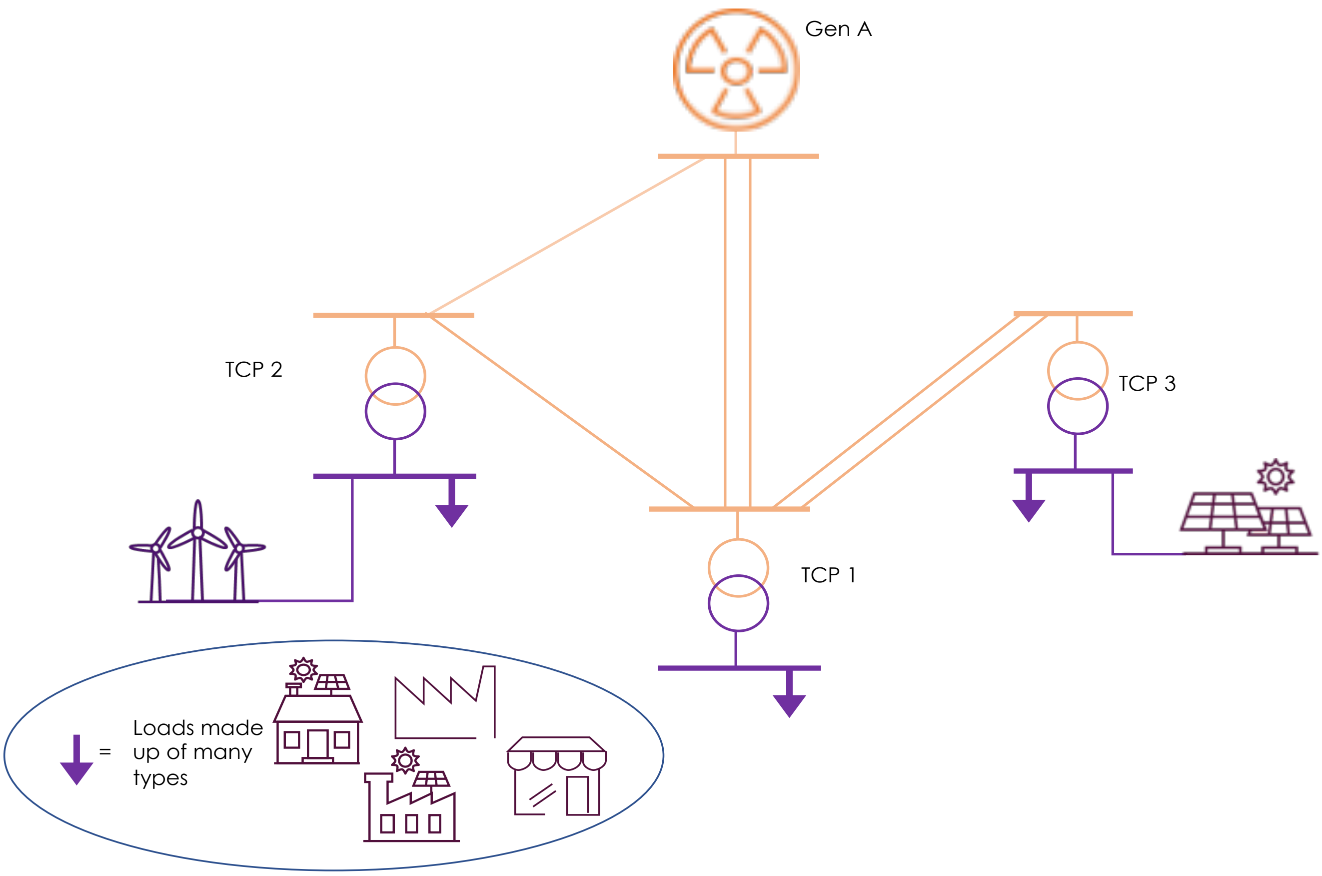

Figure 1: Example Simple Power System

Load or TCP	Offtake Energy (GWh)	Reverse Flow (GWh)	Net Flow (GWh)	Price Ignoring Reverse Flow = 35/7 = $5/MWh Amount charged to TCP	Price Subtracting Reverse Flow = 35/5.5 = $6.36/MWh Amount charged to TCP	Difference
1	3000	0	3000	$15m	$19.1m	Pays $4.10m more
2	2500	1500	1000	$12.5m	$6.36m	Pays $6.14m less
3	1500	0	1500	$7.5m	$9.55m	Pays $2.05m more
Total	**7000**	**1500**	**5500**	**$35m**	**$35m**	

Table B: Example of Non-locational charges without CAMD

It can be seen that there is a significant difference in the allocation of the charges as a result of the different treatment of the reverse flow. If load 2 had a negative flow of 3,000 GWh then the question is, if we allow reverse flow to be subtracted, then would that TCP get a zero charge or would it get a credit? Currently, the NER only provides for payment by Network Customers, not payment by AEMO as TNSP to Network Customers.

Now consider the condition of load 3 being on a Contract Agreed Maximum Demand (CAMD) rather than energy. Table C shows the load factors and how the median load can change depending on the treatment of reverse power flows.

Load or TCP	Offtake Energy (GWh)	MD or CAMD (MW)	Reverse Flow (GWh)	Net Flow (GWh)	Load Factor Ignoring Reverse Flow	Load Factor Subtracting Reverse Flow

1	3000	500 CAMD 480 MD	0	3000	0.713	0.713
2	2500	600 MD	1500	1000	0.476 Median	0.190
3	1500	550 MD	0	1500	0.311	0.311 Median
Total	**7000**		**1500**	**5500**		

Table C: Example of Non-locational charges with CAMD

A series of simultaneous equations (set out in Appendix A1) need to be solved to determine the maximum demand and energy prices.

The prices with the different treatments of reverse flow are:

Prices	Ignoring Reverse Flow	Subtracting Reverse Flow	Difference (%)
Energy Based PNLE$_t$	\$5.75/MWh	\$9.06/MWh	+57.5%
Capacity Based PNLC$_t$	\$23,973/MW	\$24,706/MW	+3.1%

The point of this example is to demonstrate that the treatment of reverse flows has the potential to have a significant impact on the price outcomes of both the energy and capacity based prices. They do not always work in a consistent manner. While this particular example shows that subtracting reverse flows ***increases*** the charges to both energy and CAMD based customers other examples show that this is not always the case. In some circumstances the capacity price may drop depending on the case.

Load or TCP	Offtake Energy (GWh)	Reverse Flow (GWh)	Net Flow (GWh)	Price Ignoring Reverse Flow	Price Subtracting Reverse Flow	Difference
1	3000	0	3000	\$12.0m	\$12.3m	Pays \$0.3m more
2	2500	1500	1000	\$14.4m	\$9.1m	Pays \$5.3m less
3	1500	0	1500	\$8.6m	\$13.6m	Pays \$5.0m more
Total	**7000**	**1500**	**5500**	**\$35m**	**\$35m**	

In this specific case customer 3 pays considerably more when reverse flows are netted off customer 2 and customer 1, who is on a CAMD, pays slightly more. Customer 2 is better off because although the rate goes up by 57.5% its energy drops by 60% and so its charge goes to 63% of the charge when ignoring reverse flows. In this case because one customer is on a CAMD based price the effect of reverse flows is dramatically affecting all the energy based customers.

A further alternative that only affects charges, and not the setting of prices, is where a net negative non-locational and common services TCP charge can be used to offset a positive TCP charge at another location within the same customer's portfolio. This is an extension of the reverse flow issue and will be discussed further on in this paper.

3.1.2 Impacts on Locational Charges

The locational charges are recovered using the MD10 methodology (see description in box below) to derive an average maximum demand for the 10 maximum demand 30 minute periods. During the last two years, some of the TCPs show a negative amount for some of these periods which will not affect the price calculation but will affect the charge. The negative amount can either be used in the averaging, zeroed out or the number of periods reduced to only those where the load is positive.

For example, if the demands in MW at the time of system maximum demand were:

1	2	3	4	5	6	7	8	9	10
80	80	90	90	70	-30	50	80	90	-50

Then averaging all values gives 55MW, zeroing the negative numbers but still dividing by 10 gives 63MW and only using the positive numbers gives 78MW. It can be seen that the different treatments in the averaging give quite different outcomes.

MD10 Methodology
The existing AEMO Pricing Methodology for Prescribed Shared Transmission Service states that:
"In calculating the locational price to recover this lump sum, AEMO will use:

- The CAMD, if the customer has elected to use a CAMD, or
- the average of the transmission customer's half-hourly maximum demand recorded at a connection point on the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the most recently completed 12 month period (t-1). AEMO will consider the most recent 12 month period to be from 1 March to 28 February."

Therefore AEMO reviews the Victorian system demand and identifies the 10 highest half-hourly maximum demand periods for the total Victorian transmission system during the previous year (1 March to 28 February). The TCP demand at the time of these 10 system maximum demands is then averaged. Each customer can elect to use its Contract Agreed Maximum Demand (CAMD) rather than this average historic demand if they have an agreement with such a value. The lower of the CAMD or the average of TCP demands at the 10 Victorian system maximum demand half-hours then becomes the denominator for calculating the TCP locational price.

3.2 Options for Treatment of Negative Flows at Customer TCP

3.2.1 Options for Non-Locational and Common Service Pricing:

Consider the situation where DNSP A has a number of TCPs but at TCP X it has a net load which is negative or in fact there is more injection into the network than load taken from the network over the year.

There are 3 options available when calculating Non-Locational and Common Services prices using the current pricing methodology. They are:

Option 1 – Allow the negative energy to be subtracted from the load

This would result in DNSP A receiving a credit on non-locational and common service charges at TCP X, which would then offset the other TCP charges and reduce their overall TUOS payments. However consequently other network users would have a higher share of non-locational and common service costs.

Option 2 – Treat the net negative value as zero at a TCP

This would result in no non-locational and common service charge for TCP X but would avoid the offsetting of other TCP charges in the same DNSP issue as shown in Option 1.

Option 3 – Only consider half-hourly consumption and treat all negative values as zero

This option would set the half-hour periods where there was injection to zero, and so the metered energy only reflects consumption. In this case if TCP X has a strong diurnal flow, the solar export would be ignored and the energy used for the TUOS calculation would only include the consumption which is mainly at night. This would result in a small non-zero contribution from TCP X to DNSP A's non-locational and common service charges. This is AEMO's preferred option.

3.2.2 Options for Locational Pricing:

Option 1 – Allow the negative demand (do nothing)

This would result in the half-hours that were negative reducing the average MD and if the overall average was negative would mean that there would be zero locational charge to this customer at this TCP. The concept of injection of power being a negative MD offsetting other 30 minute periods of positive injection is somewhat counter to the concept of maximum demand. Again this option would reduce the locational charges from DNSP A and increase the charges for other Customers.

Option 2 – Only consider positive half-hourly demand

This option would involve setting the negative 30 minute periods to zero and not including them in the averaging. This is AEMO's preferred option.

The consequence of adopting an option where the reverse values are taken into account is that they are likely to reduce charges or allow credit at the connection points where reverse flows exist. In the context of TUOS pricing, this can be considered to be distortionary. The reasoning is primarily because:

- TUOS charging is a transport charge and not a commodity charge, therefore when the reverse flow occurs it is being used by someone else in the transmission system who are paying for the transport services in much the same way as when a generator generates. The reverse flow doesn't reduce the amount of power that has already been transported and therefore should not be treated as a credit.
- There is already a mechanism in the NER that attempts to recognise the contribution of distributed generation to lowering reliance on transmission. The avoided TUOS credit is meant to recognise the contribution of local generation to reducing the demand within a distribution network by refunding to the generator the impact of its generation on the locational component of prescribed TUOS charges. Having another credit arrangement would be double counting the reward.
- The concept of only charging for withdrawals of power from the transmission network is consistent with the design of transmission pricing and is equitable and non-distortionary.

This can be demonstrated with the simple example system in Figure 1. This time consider where there are two TCPs that have zero net annual injection/withdrawal from the transmission network because they both have embedded renewable generation.

Load or TCP	Offtake Energy (GWh)	MD or CAMD (MW)	Reverse Flow (GWh)	Net Flow (GWh)	Load Factor Ignoring Reverse Flow	Load Factor Subtracting Reverse Flow
1	3000	500 CAMD 480 MD	0	3000	0.713	0.713
2	2500	600 MD	2500	0	0.476 Median	0 =Median
3	1500	550 MD	1500	0	0.311	0 =Median
Total	**7000**		**1500**	**5500**		

TCP 3 has largely solar generation and TCP 2 has wind so that they inject into the transmission network at different times of the day. They both rely on the transmission network to supply their load when their embedded generation is not generating as can be seen in Figure 2.

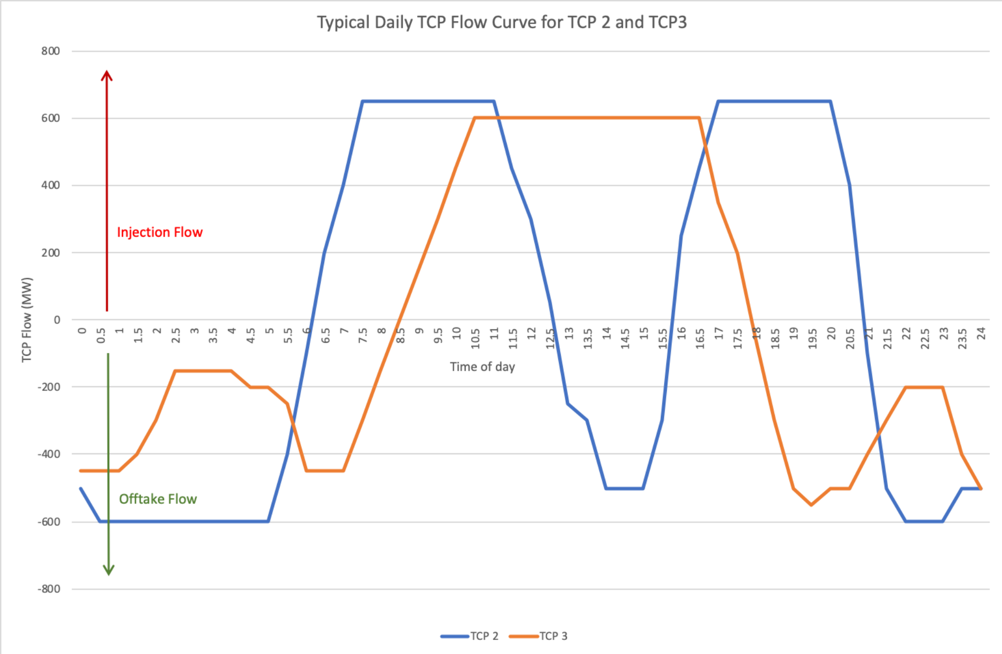

Figure 2: Example System Flows

Between the hours of 6:00 and 8:00 TCP 2 wind generators are supplying the load at TCP 3, then between 12:30 and 15:30 the solar farm at TCP 3 is supplying the load at TCP 2 and then again between 18:00 and 21:00 the wind generators are again supplying the load at TCP 3.

It is clear that the transmission system is heavily used in this situation and so these TCPs should be paying for the use of the transmission network. For the non-locational and common services charge they wouldn't be paying anything with options 1 and 2 above which is clearly not equitable for all users and may not be consistent with the principles for pricing.

Q3.1. What do you consider is the best option for treating the issue of reverse flow at TCPs using the current Pricing Methodology and please give your reasons?

3.3 Other Options – non-locational/common services

The AER Electricity TNSP Pricing Methodology Guidelines (AER's PM Guidelines) in section 2.3(b) includes the option to charge the non-locational and common services on postage stamp pricing structure based on:

1) either contract agreed maximum demand or historical energy;
2) maximum demand; or
3) an alternative pricing structure.

TransGrid adopts the postage stamp pricing based on maximum demand only. This methodology would resolve the issue of reverse flows because it would only use positive flows and the maximum half-hour load during the period over a year. TransGrid comments that it is appropriate because it further signals the drivers of transmission investments. A consequence of using maximum demand for the non-locational component of TUOS is that it uses an incentivising mechanism to the customer for what should be purely a cost recovery element of the pricing mechanism. It is arguable that a maximum demand indicator should be reserved for determination of locational component of prices. These arguments were canvassed in the TransGrid consultation on Transmission Pricing in 2014 and nevertheless, the AER approved TransGrid's proposal to recover the non-locational and common services costs through a maximum demand based tariff.

> Q3.2. Should AEMO continue with the energy or CAMD based charges for non-locational and common service charges, or consider alternatives such as the maximum demand method used by TransGrid and please give your reasons?

4. Energy Storage Systems (ESS) and Payment for Transmission Usage

4.1 Issues with ESS and Payment for Transmission Usage

The AEMC's preliminary position in the December 2018 CoGaTi Final Report[6] was that scheduled energy storage systems should not be required to pay TUoS charges. Also AEMO's proposal for a rule change "Integrating Energy Storage Systems into the NEM"[7] has recommended that ESSs should not pay TUoS charges on the basis that the ESS would pay for transmission use twice; once when it charged the storage device and once when it flowed into the final TCP to the final load. The AEMO rule change proposal does point out that a hybrid load which consists of an ESS and a load should not use the ESS to avoid payments by the load and this may require additional metering behind the connection point.

To maintain the current approach applied to pricing until the AEMO *pricing methodology* is further considered, the enforceable undertaking provided to the AER on the AEMO pricing methodology has a clause 6.2 which explicitly states that "…transmission use of system charges will not be determined or charged in respect of existing or new connection points at which large scale batteries are connected, either is respect of supply (discharging), or consumption (charging),…..".

Ofgem in its TCR review[8] refers to its own decision that ESSs should not pay residual (i.e. the equivalent of non-locational and common service) charges as they are simply intermediaries and the final user will pay this charge. However, Ofgem considers that an ESS should pay the locational charge if it adds to network congestion.

The approach of not charging for power withdrawals from the transmission network for large scale transmission connected storage may well lead to perverse incentives. The two main technologies for storage at present are pumped hydro and batteries and these have round trip efficiencies of between 80% and 95% which means that there is 5% to 20% more energy withdrawn from the network than what is reinjected at some later time. There may be an incentive to classify a load and battery pair as a

[6] https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf on page 105

[7] https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem on page 2 of rule change proposal

[8] https://www.ofgem.gov.uk/system/files/docs/2019/12/full_decision_doc_updated.pdf

low efficiency storage device so that transmission charges are avoided particularly where the TCP has a hybrid of generation, load and storage.

4.2 Scenarios

Consider these three scenarios for batteries:

- Directly connected ESS such as the AusNet Ballarat Terminal Station Battery[9]
- ESSs connected within the distribution network such as residential batteries
- An ESS connected as part of a hybrid system such as the Dalrymple Battery[10] in SA with load and a wind farm

In general, large transmission connected storage devices are not end users and therefore, to avoid end users paying TUOS charges twiceas noted above, ESS that are directly connected to transmission should not be charged TUOS when withdrawing from (or injecting to) the transmission network.

Considering the three scenarios above this means that for:

- Directly connected ESS: Consistent with the previous statements AEMO does not intend to charge TUOS for these customers.
- ESSs connected within the distribution network: For embedded batteries it is up to the DNSP to determine how they will treat these for DUOS purposes but they will not attract separate TUOS charges as they are not individually visible to the transmission system.
- An ESS connected as part of a hybrid system: If metering to the required NER standard is available on the ESS then it can be netted off the TCP flow to avoid the ESS paying for withdrawal from the transmission network. This does create a possible scenario that if battery can be managed so that all the withdrawal from the network goes into the battery and then all the withdrawal from the battery goes into the load then there will be zero load energy usage and zero TUOS charges. This situation needs to be considered further to see if it is a problem.

Q4.1. Is the proposed treatment a reasonable approach to take?
Q4.2. Do you consider that the issues regarding a hybrid connection are significant enough to warrant further investigation?

5. Peak Day versus 365 Day Method for Locational Prices

5.1 Issues with Peak Day method in Cost Reflective Network Pricing

The NER states in 6A.23.4(b) "Prices for recovering the *prescribed TUOS services - adjusted locational* component:

[9] https://www.ausnetservices.com.au/Projects/Battery-Storage

[10] https://www.escri-sa.com.au/about/

(1) must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated; …"

The current methodology uses the average of the 10 weekday maximum demand half-hours on the system wide maximum demand days to set the prices. However, choosing a subset of conditions that occur during a year is now problematic because the period "of greatest utilisation of the transmission network" isn't simply the maximum demand of the power system.

For example, the AEMO Western Victoria Renewable Integration project[11] report stated in its executive summary that:

"It is estimated to cost $370 million and deliver gross market benefits of $670 million and net market benefits of $300 million (all figures in present value). This net market benefit is achieved through:

- Significant reductions in the capital and dispatch cost of generation.
- Facilitation of future transmission network expansion.
- Improvements to the Victoria to New South Wales interconnector transfer limit."

Unlike most previous RIT-Ts there is no reliability improvement or reduction in unserved energy at peak demands, so that maximum demand days is not the driver for this new augmentation.

Another option in determining the locational prices is the 365 day method which subject to the AER Guidelines, looks at all hours during the year and finds the one with the maximum utilisation of each element. This means that if the element is loaded by high wind at 10pm on a winter's night then that will be used in the allocation. This methodology appears to be better aligned to clause 6A.23.4(b) above.

the 365 day methodology is a more commonly use within the NEM and the reasons stated are:

- Difficulty of picking the period of greatest utilisation when the 365 day method subject to the AER Guidelines actually looks at all hours during the year and identifies the peak utilisation of the network elements, and
- Maximum demand does not always necessarily drive investment.

The inter-regional transmission pricing review report by Roger Bolden[12] identified that AEMO was the only TNSP that used MD10 rather than 365 days and suggested that the 365 modelling provided much more consistent price signals across years.

Another issue is that AEMO consults with each Transmission Customer about the actual 10 days selected and there have been issues raised by Transmission Customers about events that happened on that day that they consider would unfairly impact their prices. The 365 day methodology appears to minimise this issue.

Q5.1. Is the 365 day methodology a reasonable approach to take, if not please give your reasons?

[11] AEMO Western Victoria Renewable Integration project regulatory investment test for transmission (RIT-T) in its final Project Assessment Conclusions Report (PACR) July 2019, page 4

[12] AEMO ERC0106 ROLIB Modelling Report page 6 https://www.aemc.gov.au/sites/default/files/content/79577b07-8892-430a-8e50-87929a42a6cc/ROLIB-Modelling-Report.PDF

6. Other issues

Are there any other issues relevant to the subject matter of AEMO's Pricing Methodology that stakeholders wish to raise.

Q6.1 Do stakeholders have other issues to raise? If so, please provide context and reasons.

7. How we will Consult on these Matters

7.1 Requirement to consult

Under the National Electricity Rules, the AER must approve AEMO Pricing Methodology and is required to consult. AEMO is consulting with participants to inform AEMO's revised Pricing Methodology to be submitted to the AER. AEMO intends to provide the AER with the revised Pricing Methodology on or before May 2021 so that the AER has sufficient time to consult before approval.

7.2 Timing

AEMO's consultation will take place according to the following timetable. Dates are indicative and subject to change. Stakeholders are requested to forward their response to this Issues Paper (and any questions and queries relating to this consultation) to pricing.methodology@aemo.com.au by 5pm 29 September 2020.

Initial Consultation (this Issues Paper)	Responses due 5pm 29 September 2020
Issue consultation paper & engage stakeholders	26 October – 30 November 2020
Feedback to stakeholders	8 – 15 February 2021
Submit proposed Pricing Methodology to AER	May 2021

A1. Pricing Formulas

A1.1 Non-locational Pricing

A1.1.1 Maximum demand and energy prices

$(AB_{t-1} \times PNLe_t) + (CCMD_t \times PNLc_t) = NLC_t$ (1)

and

$(ME_{t-1} \times PNLe_t) = (MMD_t \times PNLc_t)$ (2)

where:

AB_{t-1}	=	total annual billable energy (MWh) in year t-1 for all connection points in which the energy based price for recovery of the adjusted non-locational component applies in year t
$PNLe_t$	=	adjusted non-locational component energy based price in year t
$CCMD_t$	=	sum of CAMDs for all connection points at which the CAMD price for recovery of the adjusted non-locational component applies in year t
$PNLc_t$	=	adjusted non-locational component CAMD price in year t
NLC_t	=	adjusted non-locational component in year t
ME_t-1	=	median load factor customer's historical metered energy offtake in year t-1
MMDt	=	median load factor customer's average maximum demands in year t-1