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Prepared for the Electricity Authority – Transmission Pricing Methodology

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Electricity storage and residual transmission charges

This note provides an early high-level analysis of the issues and possible solutions for the treatment of electricity storage when allocating residual charges under a new transmission pricing methodology. It has been prepared to support further thinking.

Issues

Imposing residual charges on electricity storage could inefficiently inhibit investment in such technologies. This could be a significant problem, judging from experiences elsewhere in the world where investment in storage – such as grid-scale batteries – have significantly reduced costs of ancillary services and provided alternatives to investment in transmission and distribution networks.

Residual charges, for revenue not recovered from benefit-based charges, are to be allocated to electricity users (demand or measured withdrawals).[1] Producers will not face residual charges on the grounds that this could distort generation investment decisions and do so needlessly in the sense that in the long-term costs will ultimately be recovered from consumers.

Electricity storage falls in a grey area between users and producers. Storage uses electricity in the sense that metered kWh input is large and larger than metered kWh output. But storage also produces electricity services in the sense that:

- the dollar value of their output is, on average, larger than the dollar value of their input (i.e. they add value in transformation - specifically shifting of supply through time)
- they provide a substitute for services provided by energy generation technologies - such as instantaneous reserve and voltage support - and in this sense they belong to the producer rather than the consumer side of the market.

Hydro power stations that supply (tail water depressed) spinning reserve would also face residual charges, to the extent that they draw electricity in order to supply reserve. However, residual charges will not be paid by instantaneous reserve offered by thermal power stations or by offers of reserve from stations generating below capacity (partially loaded reserve).

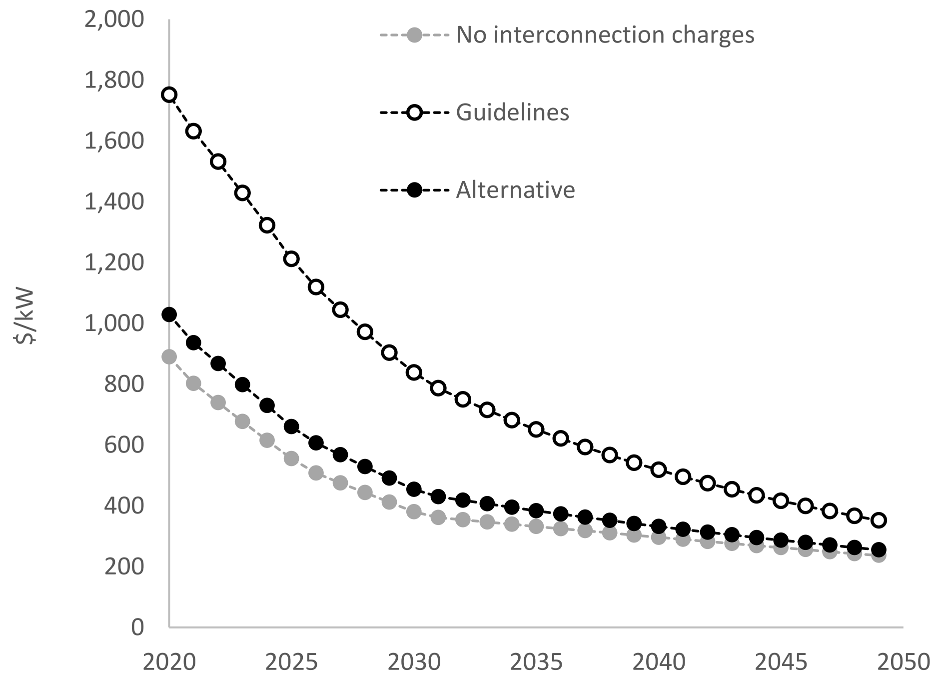
[1] The charges are expected to recover around 70% of interconnection charges in the first few years of the new TPM, declining to around 40% of interconnection charges in the late 2020s.

Residual charges add costs to storage not faced by most other producers of electricity services

The current approach to allocating residual charges is likely to reduce investment in energy storage in favour of investment in technologies that do not use electricity as an input. The effect will vary depending on the size and location of the investment.

The effect is likely to be strongest for new investment in grid-connected electricity storage. If storage were to be treated as load, new investment in grid-connected storage will face residual charges that are commensurate with charges that they would have faced had they been fully operational in July 2014.[2] A 100MW grid-connected battery would likely face a charge in the order of $10 million if it was installed in 2023. This cost will approximately double the costs of investment in grid-connected batteries (see assessment in Figure 1).

FIGURE 1: IMPACT OF INTERCONNECTION CHARGES ON GRID-CONNECTED BATTERY COSTS[3]
Scenarios for battery investment costs: (a) no interconnection charges (residual and benefit-based charges), (b) interconnection charges reflecting the TPM guidelines, without adjustment or exception (c) an alternative with residual charges levied on final demand.



Charges are likely to discourage large scale investment in storage and encourage investment in smaller storage in distribution networks

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[2] On the assumption that a newly connected generator (which a battery would be under the code) is considered a new designated transmission customer for the purposes of 33 (a) (i) of the transmission pricing guidelines.
[3] The estimates of battery costs used here are the same as those in the TPM Technical paper CBA approach method and assumptions, 10 June 2020.

Other electricity storage investments are likely to cause smaller cost increases. For example, a 1 MW battery installed in a distribution network would result in a comparatively small increase in residual charges, assuming that the use of the battery was not considered a substantial increase in demand. A small investment would cause a very gradual and probably trivial increase in residual charges over time, with residual charges rising with any increase a distribution customer's rolling annual average MWh of demand lagged by five years.[4]

Furthermore, distributors are not compelled to pass these charges on to the owners of batteries and consequently distribution-connected batteries could avoid charges altogether.

Options to explore

Options include applying the transmission pricing guidelines as written (residual charges faced by all designated transmission customers to the extent they are load customers) or a departure from the guidelines to reduce the exposure of energy storage to residual charges.[5]

Option to calculate gross demand based on gross final demand

One way to reduce the exposure of energy storage to transmission charges would be to amend the gross load calculations to be about gross final demand – thereby excluding from residual charges any energy that is imported for the purpose of further resale in the electricity market.

Other jurisdictions exempt demand from charges if that demand results in market services

Storage is exempt from transmission charges in several other jurisdictions, to avoid distorting investment decisions. These exemptions typically consist of grouping storage with similar service providers and designating all providers of those services as exempt from charges.

In some jurisdictions (e.g. PJM in United States) this is done by exempting providers of specified network support services from having to pay transmission charges in respect of energy used for the purposes of performing those services.

Other jurisdictions simply exempt suppliers from transmission charges levied on demand

In other jurisdictions (e.g. the UK) storage is given its own participant category and, alongside generation, that category is excluded from transmission charges. Entities are considered to be storage

[4] It is unclear what the scale of this increase in MWh would be. The net increase in MWh of grid-offtake would be small and equal to the amount of energy lost during conversion by the battery. The guidelines require that the MWh also include any concurrent generation so in principle MWh of battery discharge would be factored into calculations of growth in MWh and would imply an approximate double-counting of increases in MWh in terms of economic value. In practice, the amount of battery discharge captured in MWh growth calculations is likely to depend on the size of the battery, the visibility of its output and the exact methods used to construct a reasonable estimate of concurrent generation in distribution networks.

[5] A departure from the guidelines is possible in principle under clause 2 of the guidelines "if Transpower considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with these Guidelines in their entirety".

or generation based on their primary activity. However, this is potentially open to debate, and thus charge avoidance.

The Authority's approach to allocating residual charges suggests an approach that is based on activities or services rather than entity designations. The Authority did not differentiate between generation entities and load entities because it avoids creating incentives for entities to shift their classifications (boundary effects).[6]

How to allocate residual charges on the basis of final demand

Our reading of the TPM guidelines' intent section is that the above options could be accommodated by applying clause 2 of the TPM guidelines. However, the Authority should test this.

Provisions in the proposed TPM would not need to be much more complicated for allocating residual charges on gross final demand than they are for allocating charges based on gross load as currently expressed in the TPM guidelines. They would only require the addition of the term final demand.

Final demand could be specified as either final consumption, which includes use of energy for the direct support of production of energy but excludes losses during transformation or transportation, or it could be taken to include final consumption plus losses in transformation or transportation. To avoid the possibility of perverse incentives to reduce the efficiency of transformation, it might be wise to use a final demand measure that includes losses during transformation. However, a decision to include or exclude losses during transformation could reasonably be made on pragmatic grounds, given the absence of clear reasons to use one approach over the other.

Given this, Transpower might estimate gross final demand as the sum of, for example[7]:

1. the net quantity of electricity flow from the grid at that point of connection;

   and

2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection,

   less

3. *Transpower's reasonable estimate of the quantity of 1. and 2. used directly by generators' generating units in the provision of wholesale market services, excluding energy consumed or losses during transformation.*

Wholesale market services include dispatched energy and ancillary services. For the avoidance of doubt 3. applies only to generators and does not apply to interruptible load – which might otherwise contend that maximum demand contains a component of load shifting that enables the provision of instantaneous reserve in other trading periods.

[6] Although this approach creates measurement problems and transaction costs associated with measurement.

[7] The first two elements of this calculation are from the guidelines. The intent in this example is to suggest demand measurement methods for the purposes of both initial residual allocation and for rolling updates of the residual allocations over time.

For grid-connected storage – such as batteries or pumped hydro – with no co-connected load, estimating gross final demand would be reasonably straight forward, applying an efficiency factor to 1. based on the technical specifications of the storage.

Estimating gross final demand for networks with embedded storage would be more complicated because it would require information on the actual operation of storage to determine what proportion of grid exports was used to power a battery. Here reasonable estimates could be obtained by use of reconciliation data. Noting, however, that operation of small-scale embedded storage such as residential batteries would be invisible, at least for the time being.

A lack of information about small generators, their capacity and activity, is being considered by the Authority in the context of facilitating wholesale market participation of distributed energy resources. That is, this is not a problem peculiar to transmission pricing.

Efficiency of options

To assess the efficiency of alternative arrangements for allocating residual charges we consider impacts on:

- suppliers of electricity services, differentiated by connection configuration (whether grid connected or distribution connected)
- consumers who self-supply or co-supply electricity services (e.g. load with co-located generation)
- third parties (e.g. aggregators).

Our assessment is based on three effects of residual charges:

- the direct effect of the charges on fixed and variable **operating costs**, which goes to the scale of issues of stake
- the effect of increased operating costs on the efficiency of **wholesale market prices**; accounting for the fact that
  - it is inefficient for residual charges to flow through into wholesale market offers and prices because this sends inaccurate signals about economic costs of production and cause deadweight losses from reduced demand for electricity
  - these costs will only be passed on if they are common to a substantial majority of suppliers or, equivalently, if the supplier has market power
- **investment inefficiency**, with higher supply costs for some investments causing[8]:

[8] This assessment side-steps questions about the effects of differential treatment of electricity powered generators and gas-powered generators on the grounds that these effects are ambiguous, a context-specific empirical matter and as much a matter for gas market regulation and commercial practice as it is a matter for the electricity market.

Gas-powered generators could face comparatively higher fuel transport costs than electricity powered generators regardless of whether electricity-powered generators faced transmission residual charges. There would be cause for concern if residual charges were an avoidable economic cost - in which case exempting electricity powered

– investments being at inefficient scale or in less efficient places or

– economically more expensive technologies being chosen over cheaper technologies or

– reduction in the rate of learning about new technologies or

– reduction in competitive pressure in the generation market due to increased barriers to entry.

Table 1 provides a summary assessment of the relative effects of the guidelines versus the option to allocate residual charges based on final demand.

Under the alternative, residual charges have a markedly smaller effect on operating costs of electricity storage (in this table batteries and pumped hydro). Consequently, effects on investment inefficiencies are much reduced.

The alternative will limit distortions to wholesale prices. Under the guidelines there could be an uplift in offers in the reserve market[9], given that the residual charges would be faced by a substantial majority of generators providing instantaneous reserve. This uplift is not certain, given that the residual charges are quasi-fixed operating costs and that thermal generators would not face those costs.[10]

generation from residual charges would be a subsidy that could cause inefficient investment. However, the residual charge is not an avoidable economic cost.

If gas pipeline owners choose to charge generators the equivalent of electricity transmission residual charges it does not follow that the Authority should assume that such charges are efficient or attempt to match them.

[9] We assume that batteries can provide generation for the purposes of instantaneous reserve. This is not permitted in the Code but is likely to be permitted in future.
[10] Here we are distinguishing between higher wholesale prices due to pass-through of costs and higher wholesale prices that could result from investment inefficiencies.

TABLE 1: SUMMARY ASSESSMENT OF EFFICIENCY OF OPTIONS

Counterfactual is no transmission charges at all

Supplier	Operating costs		Wholesale prices[11]		Investment inefficiency	
	Guidelines	**Alternative**	**Guidelines**	**Alternative**	**Guidelines**	**Alternative**
Grid connected batteries	+ + +	+	+		+ + +	+
Pumped Hydro	+ + +	+	+		+ + +	+
Load embedded behind a generator[12]	+	+			+	+
Distribution network batteries	+ +	+			+ + +	+
Embedded generation - small scale[13]						
Embedded generation - large scale[14]						
Aggregators of DER			+		+	
Spinning reserve[15]	+	+	+		+ +	+

Empty cell = no effect, +/- = small increase/decrease, + + / - - = moderate increase/decrease, + + + / - - - = large increase/decrease

Potential for distortions to wholesale prices could also carry over into the relative risks and returns to offers across different services. For example, if following the guidelines increases the cost of providing reserves or reactive power, it could cause changes in the mix of services provided by generator or even, at the margin, trading conduct. Of course, the area where these effects would be most profound would be in any increased barriers to entry and related investment inefficiencies.

Application of the guidelines could also create a price signal that favours installing several smaller batteries in distribution networks rather than a single large distributor- or grid-connected battery. Installing several smaller batteries in a distribution network is less likely to attract a reassessment of residual charges compared with installing a single large battery. This is because reassessment of charges is only likely to be triggered by the installation of batteries that could viably be connected to the grid. The importance of this effect depends on methods used in practice to trigger and implement a reassessment of residual charges, including methods to determine if a battery (or batteries) could have viably been connected to the grid.

Under both the guidelines and the proposed alternative, load that embeds behind a generator would face residual charges if the load is existing load (i.e. changes its point of connection). However new load that embeds behind a generator would only face residual charges if the GXP the generator is connected to has exhibited a positive net quantity of electricity flowing from the grid or if Transpower identifies the new load as a substantial and sustained change in activity and consequently alters the generator's charges to reflect the new load. This raises potential efficiency issues, common to both the guidelines and the proposed alternative – by creating an incentive for smaller load to connect behind a generator. The size and importance of this incentive is unclear and dependent on idiosyncratic circumstances. In general, the costs involved for small load to connect to a grid-

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[11] Including energy and reserves and ancillary services.

[12] Assumes the generator is not also a load customer.

[13] Assumes distributors do not pass load charges onto generators.

[14] Assumes distributors do not pass load charges onto generators.

[15] Assumes (i) modest power consumption by tail water depressed spinning reserve (ii) hydro dominates the market for spinning reserve and consequently transmission charges are passed on in reserve offers.

connected generator will be prohibitive relative to the alternative of connecting to a distribution network.[16]

Embedded generation, whether large scale or small scale (such as residential solar PV), is unlikely to be affected by residual charges because it is unlikely that distributors would allocate residual distribution charges to embedded generation based on their output – largely because this would be inefficient. Although residual charges are allocated on gross load – to take account of load being served by embedded generation – the sole driver of residual charges is load. That is, if embedded generation increases but load (MWh) does not increase, then residual charges do not increase (other things being equal). Noting also that residual charges only increase if load (MWh) grows faster in a distribution network relative to the national average and even then the residual charges will increase very slowly with charges adjusted by the three year rolling annual average growth in consumption lagged by 5 years.

Aggregators of distributed energy resources will not face direct operational costs. However, under the guidelines, development of the market for aggregation of distributed energy resources will be constrained a little by residual charges imposing a tax on load shifting using energy storage – albeit the effect of the tax will be muted significantly by the protracted adjustment mechanism for residual charges. For this reason it is likely that there will be small effects on wholesale prices and on investment efficiency under the guidelines.

[16] Where costs of connection include lines and equipment and other economic costs from choosing to locate at a distance from markets and other services.

International experience

Electricity industry rules are in a state of flux internationally as regulators and market participants try to determine how best to accommodate energy storage within rules that have traditionally defined market participants as either load or generation.

Australia proposing new class of industry participant that will not face transmission charges

Australian regulators are currently reviewing market rules with a view to introducing a new class of industry participant for energy storage assets – in order to clarify the treatment of energy storage in market rules and for the purposes of determining if they are eligible for transmission charges.

In Australia generators do not pay directly regulated (interconnection/shared costs) transmission or distribution charges, however they do pay negotiated charges for costs directly associated with establishing and maintaining their connection to a transmission or distribution network.

Currently storage that takes in electricity and exports electricity must register as both a load participant and a generation participant and, in the absence of bespoke arrangements, transmission-connected energy storage systems are liable to pay TUOS charges if they are a customer.

ElectraNet sought an exemption from the AER from TUOS charges being payable for the ESCRI-SA battery on the basis that the transmission services being provided under the terms of the connection agreement between AGL and ElectraNet will comprise negotiated transmission services (network support services). The AER agreed that TUOS charges would not be payable at the connection point under the National Energy Rules. However, the AER did not consider that this approach should set a precedent for all future projects.

AEMO is consulting on introducing a Bi-directional Resource Provider participant category. Part of their proposed changes include that Transmission use of system (TUOS) charges should not be charged for bi-directional assets, but that distribution use of system (DUOS) charges should be levied on the load component of bi-directional assets. A further options paper is pending on these matters.

In 2018 the AEMC said "The Commission's preliminary position aligns with that of AEMO's, i.e. if an energy storage system is a scheduled resource and can be constrained off the network, it should not be required to pay TUOS charges". AEMC is also consulting on new arrangements for DER, with respect to DUOS charges.

Treatment of storage under review across the European Union

DG Energy (March 2020) recently reviewed the treatment of energy storage in member states' electricity markets, including with respect to transmission charges. The review noted that several member states are in the process of implementing changes to transmission pricing to avoid problems of double-charging of storage that is treated as both generator and load for the purposes of transmission pricing.

Transmission pricing practices vary considerably in the EU. Several charge generators and load for transmission interconnection costs (typically at less than 50:50 ratio). This has the effect that storage, including pumped hydro, faces both demand charges and generation charges in some member states and also faces the problem that load is charged both when energy is stored and again when it is finally consumed. Other member states recover transmission interconnection costs solely from load, leading to charges being levied twice on energy that is stored and then consumed and also creating an uneven playing field with respect to other providers of services such as reserves and voltage support.

United Kingdom decided not to levy residual charges on storage

In the United Kingdom recent changes to transmission charging mean that from next year generators will no longer face residual charges (or receive payments for embedded generation). In October 2020 Ofgem further decided that, in line with earlier decisions, "residual charges should be paid by final demand only, thereby excluding all types of generation (including stand-alone storage) from residual network charges".

United States exempts storage from charges where it provides market services

In the United States, rules that distinguish storage assets from generation or load are well-developed compared to other jurisdictions but only in the case of storage assets being used for ancillary or network support services. The treatment of storage in other instances is less clear.

FERC has ruled that energy storage must not be charged transmission charges if it is providing scheduled network support services (including frequency keeping, reliability/reserves and voltage support). This is intended to ensure even-handed treatment of energy storage in the market for network support services.

For other services provided by energy storage, FERC has said that it will make decisions about the treatment of these services or assets on a case-by-case basis depending on the both the specific services being provided by energy storage assets and the context in which they are provided. Thus the treatment of storage assets remains a matter for the judgement of regional transmission and independent system operation organisations.

FERC has resisted requests to clarify that rules applicable to generation apply equally to storage and has clarified that it sees that storage is a distinct category of activity that is materially different to generation. In one case FERC found that storage assets could be treated as transmission assets.

The Californian system operator (CAISO) does not levy residual transmission charges on energy storage, which it views as consistent with its practice of not levying residual charges on generators. CAISO created a separate customer category of 'non-generator resource' for energy storage.

CAISO's treatment of storage has been approved by FERC but FERC has noted that approval did not constitute a precedent in terms of whether such treatment is necessarily always consistent with FERC rules.

FERC has said that where energy storage is exempted from transmission charges the system operator must show that the exemption is reasonable given the existing rate structure for transmission charges.

The independent system operator in Pennsylvania, New Jersey and Maryland (PJM) treats large Pumped Hydro Storage Units as generators and does not assess transmission charges to them. However it does treat some charging of other forms of storage as load, for the purposes of transmission charges:

- energy export is exempt from transmission charges if it is for reinjection and to provide ancillary services
- otherwise energy export attracts transmission charges (charges which are wholly charged on load in the PJM region).

Other operators have attempted to exempt all storage from transmission charges, but have been rebuffed by FERC.

IN 2019 the New York Independent System Operator (NYISO) proposed to treat the charging of storage as negative generation that does not attract any transmission service charges, to the extent that withdrawal is for later injection to the grid. This was consistent with long-standing practice of not charging pumped hydro stations demand-side transmission charges.

NYISO's approach was rejected by FERC on the grounds that it treated storage differently to other load. The rejection was at least partly a matter of procedural principle rather than a rejection of the decision to exempt storage from transmission charges levied on load (noting that CAISO's decision not to charge energy storage for transmission charges, based on withdrawals, was approved by FERC).

However, FERC did say "We do not find the assessment of transmission charges twice in this instance to be unjust and unreasonable because the electric storage resource uses the transmission system once in withdrawing energy for later injection and wholesale load again uses the transmission system when withdrawing that same energy for resale to end-use customers. Accordingly, two different transactions occur: one that entails the electric storage resource purchasing charging energy at wholesale from the RTO/ISO market and another that entails wholesale load purchasing energy from the electric storage resource via the RTO/ISO energy market. As such, we find that it is reasonable to apply transmission charges to both the electric storage resource and the loads associated with those separate transactions, and for load to ultimately pay the two transmission charges." (172 FERC ¶ 61,119, para 22, August 2020)

The FERC, in August 2020, rejected similar applications from the New England ISO to exempt storage from transmission charges. The FERC directed tariff revisions:

- specifying that [the ISO] will not apply transmission charges to electric storage resources when they are dispatched to withdraw energy to provide voltage support and reactive control, provide operating reserves, provide regulation, balance energy supply and demand on an economic basis, or address a reliability concern; and
- applying transmission charges to electric storage resources when they are not being dispatched to provide one of those tariff-defined services.

New England ISO is proposing to specify that storage is exempt from charges where it "is providing one or more of the following services: reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern. Electric Storage Facilities shall be considered to be balancing energy supply and demand when they are responding to ISO dispatch instructions in the Real-Time Energy Market."