TESLA

Joel Aulbury
Australian Energy Market Commission

16 September 2021

Re: Integrating Energy Storage Draft Determination (ERC0280)

Dear Joel,

Tesla Motors Australia, Pty Ltd (Tesla) welcomes the opportunity to provide the Australian Energy Market Commission (AEMC) with feedback on its Integrating Energy Storage Draft Determination.

From the perspective of facilitating energy storage integration into the National Electricity Market (NEM), Tesla only partially supports the rule proposal as currently drafted. It provides some improvements for aggregated, distribution-level storage assets, however it does not represent a significant improvement on the status quo for grid-scale storage systems. As per the intent of AEMO's original rule change request, the market is looking to the AEMC to remove existing inefficiencies in the registration and connection process for stand-alone and hybrid facilities, as well as to create requisite certainty to ensure integrated resource units (i.e., 'storage') can be deployed at the speed and scale required.

The original proposal was for a single participant category for storage (including hybrid systems), which would include appropriate technical parameters, requirements, obligations, and charges. This was a simpler, clearer, and more cost-effective design to capture the unique characteristics of storage. There is a wealth of international experience that can be drawn upon to support this position, some of which is captured in our response below. Whilst we understand the intent of the AEMC to take a 'service-based approach', this is a significant shift from the intent of the original change proposal and does not adequately address the issues that have been raised over the past 3 years.

In particular, appropriate consideration and application of Transmission and Distribution Use of System (T/DUOS) charges is needed to support the efficient integration of storage in a way that aligns with the National Electricity Objective (NEO). Efficient investment in, and operation of storage is predicated on having fair and cost-reflective marginal costs (that equate to the marginal benefit or service provided). Taking a service-based approach that assumes T/DUOS charging applies to all storage leads to a scenario where grid-scale assets face inequitably higher risks and costs that could exceed the benefit of providing those services, distorting the market, and creating significant long-term consequences for consumers. AEMC must consider these wider impacts before maintaining that T/DUOS mapping to all customers is adequate for all storage. In our view, this fails the NEO, is a narrow interpretation of load, and fails the original purpose of the rule change.

Through this lens, Tesla currently supports only isolated aspects of this rule change. Specifically, we support the definitional changes to combine FCAS classifications, and provide in-principle support for aggregated, distribution assets accessing all FCAS markets. However, this should not be seen as implicit support for the introduction of a general Integrated Resource Provider (IRP) category as currently drafted. We hold significant concerns on the application of T/DUOS charges, reduced bidding flexibility, and unintended RRO liabilities for grid-scale storage systems. As such, we recommend progressing the FCAS changes as a matter of priority, de-coupled from other aspects of the rule change if they require more time for design or implementation.

If these issues remain unresolved, this rule change will be a significant lost opportunity to facilitate the efficient integration of storage, and when factoring the investment in time, cost, and resourcing on AEMO (and associated burden on market participants), would represent a substantial net cost. Further detail on these points is included in the response that follows.

Kind regards,

Tesla Energy Policy Team
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Context

Appropriate planning and integration of energy storage is vital for the long-term reliability, security and emissions reduction ambitions of the Australian energy market. This is widely recognised by all market bodies: AEMC's draft determination itself calls out the importance of storage; with AEMO's 2020 Integrated System Plan anticipating that up to 50GW of new large-scale renewable energy generation will be supported by almost 20GW of new storage capacity (per the step change scenario) to provide resource adequacy. This capacity will be made up of pumped hydro, large-scale battery energy storage systems, and distributed batteries, including virtual power plants (VPPs).

In addition, storage is becoming increasingly critical to provide essential system services and network support, as recognised by NSW Government's 2GW storage target, and the Victorian REZ Development Plan to integrate 2.4GW of storage across the state. Achieving these targets will become substantially more challenging if this rule change proceeds as currently drafted.

AEMO's latest white paper on advanced inverter technologies[1] also highlights the importance of inverter-based technologies, grid-forming battery storage in particular, in supporting the transition to high penetration renewables, and the need for new assets to provide inertia, system strength, and voltage stability in place of a retiring synchronous thermal fleet.

Storage is more than simply passive load. It is a proven technology, with demonstrated benefits for reliability, system security, affordability, and emissions reduction. Storage technologies are readily available and technologically superior to fossil-fuelled alternatives, but efficient integration at the speed and scale highlighted by AEMO will require reforms and rule changes that recognise its active and beneficial role in the market, and must avoid the introduction of additional barriers, uncertainties, challenges and risks.

Issue A: Transmission/Distribution Use of System (T/DUOS) charges should not apply for storage

Overview of Tesla position

The basis for allocating T/DUOS on market customers is to ensure that network service providers (NSPs) are adequately compensated for maintaining existing network infrastructure to ensure ongoing reliable and efficient supply of energy at all times – both peak and off-peak; as well as for investing in new infrastructure to meet projected increases in peak demand.

From first principles, these charges should naturally fall to end-customers that are passively using the network to receive a service or benefit– i.e. traditional load customers. The NEM framework includes the principle that generators, who don't receive an equivalent service of firm access at the connection point itself, do not pay TUOS charges, instead providing connection payments for network services. The AEMC's own analysis *"assumes that this will continue to be the case"*. This makes sense for grid-scale storage (or scheduled Integrated Resource Units (IRU)) as well, as a connecting storage unit (ultimately a supply-side asset), must negotiate with the NSP for a power transfer capability at the connection point and should therefore only pay the connection charge that relates to the cost of their connection to the network.

In other words, T/DUOS charges should only apply to customers that drive network expenditure to meet increased load requirements (in exchange for firm access services). Historically, the definition of 'load' or 'customer' adequately captured this pool of participants. However, this is not fit for purpose for scheduled and highly controllable assets such as grid-scale storage / scheduled IRU which form (as NSPs themselves refer) "*part of the network supply chain*" and are not simply equivalent to being a generator combined with an end-customer load. From a technical perspective, storage assets neither consume nor produce electrons. All electrons are stored in the asset for export back into the grid at a later point in time by an independent end-use customer (who *is* charged T/DUOS on those electrons).

[1] https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf?la=en&hash=B4E20D68B23F66090ADA5FD47A50D904

The current framework is based on these historical definitions of load services and customers – as the AEMC itself notes: *"Given that the current framework is set up around transmission businesses planning to provide transmission services that are for the benefit of consumers, it follows that end-use consumers pay for the costs (investment and operational) incurred by the TNSPs in providing these shared transmission services. Consumers therefore pay TUOS charges."* **Storage assets are not 'end-use consumers'** and should therefore not be considered as load customers in this traditional sense. Storage systems are multi-functional assets – providing a range of different services – critical to enabling increasing integration of low-cost renewables and replacing system security services traditionally provided by the synchronous generation fleet.

What the AEMC fails to distinguish in their Draft Rule is the different types of storage assets that currently connect in the NEM and their different operating characteristics. Tesla has provided a high-level summary of these assets and our position on T/DUOS exemptions in the table below. This Rule Change needs to recognise the fundamental operating differences between passive customer-owned storage, and grid-scale systems, such as Hornsdale Power Reserve, which would be registering as scheduled IRU.

Class of asset	Current registration options	Changes per IES rule change	Tesla position on T/DUOS exemption
Passive residential battery system	N/A	N/A	**No change under this Rule Change.** DUOS continues to apply with any changes through the Network Access and Pricing/ ESB reforms
Aggregated active BTM residential battery system / VPPs	MSGA in some instances	IRP / small integrated resource units	**No change under this Rule Change.** DUOS continues to apply with any changes through the Network Access and Pricing/ ESB reforms
Aggregated small distribution connected battery storage systems (i.e. community storage)	MSGA	IRP / small integrated resource units	**No change under this rule change.** This needs to be a broader discussion on appropriate tariff structures for community level assets (e.g. Local use of System Charges).
Scheduled distribution connected storage assets (>5MW)	Scheduled Generator and scheduled load	IRP/ scheduled IRU	**Rule change should lock in DUOS exemption for reasons outlined**
Scheduled transmission connected storage assets (>5MW)	Scheduled Generator and scheduled load	IRP/ scheduled IRU	**Rule change should lock in TUOS exemption for reasons outlined**

To be clear, Tesla is not looking for a blanket T/DUOS exemption for every storage asset. As per the delineation in the table above, our position relates to grid-connected, stand-alone storage (scheduled IRU).

Summary arguments against T/DUOS being applied

The AEMC have suggested they are no longer seeking to introduce a specific technology category to encompass storage but are moving to a services-based approach. However, there is an inherent contradiction here, as the Draft Rule still introduces the (scheduled / non-scheduled) Integrated Resource Unit – which is effectively a registration category and classification for only bi-directionally assets (i.e. storage).

Beyond these fundamental definitional issues, we include 7 underlying principles to support the position that T/DUOS for scheduled IRU would be inappropriate, discriminatory, and misaligned with the NEO:

1. NER is clear on cost drivers and misallocations to grid-storage results in higher costs to consumers
2. T/DUOS charges for grid-scale storage create an effective cross-subsidy to true end-customers
3. Grid storage responds to market signals and T/DUOS distorts market outcomes and lowers competition
4. Grid storage pays full generator connection costs (and meets strict GPS) but does not receive firm access

5. No other electricity generators incur network usage costs to provide wholesale energy or system services – placing grid-scale storage at a disadvantage (i.e. it is not technology neutral)
6. Grid-scale storage is highly controllable, dispatchable, with two-way response for energy and network services – a very different operating profile to traditional load, passive behind the meter storage
7. T/DUOS charges kill the commercial viability of all grid storage projects, causing inefficient investment in alternative network and/or less flexible generation assets – resulting in higher costs to consumers

Relying on negotiated outcomes with NSPs preserves existing uncertainties for investors, frames payments as necessary, and is not a good outcome for the AEMC to leave un-addressed in the final determination.

We note several international jurisdictions have recognised these principles and accordingly introduced specific exemptions for storage to avoid paying use of system charges (detailed further below).

Alternative Options need further consideration

The application of T/DUOS is evidently an important and contentious issue for storage proponents, networks, consumer advocates, and market bodies alike. Linking back to the original intent of the rule change proposal (i.e. to make it easier to develop, connect, register, and operate storage in the NEM) the AEMC may want to give further consideration to how T/DUOS applying to grid-scale storage registering as scheduled IRU can map to its stated 'services-based approach':

- If the AEMC is unwilling to consider an exemption for grid-scale storage (i.e. scheduled IRU), there may still be an opportunity to provide some level of certainty. For example, the AEMC could embed a negotiation framework in the NER where the base case assumption is for no T/DUOS charges applying to scheduled IRU, and with the burden of proof resting with NSPs to justify any non-zero charges to projects. This could be done via NSPs seeking AER approval (provided certain criteria are met), or through clear AEMC supported guidelines that ensure transparency, jurisdictional consistency, and minimise investment uncertainty (i.e. an opt-out T/DUOS exemption).
- If the end-goal is to create a framework of cost-reflective tariffs and charges under a two-way trading participant model, it would be better for AEMC to provide certainty for T/DUOS exemptions for grid-scale storage (even if only as an interim position) ahead of these cost-reflective tariffs being designed and applied to all loads, generators, and storage technologies. We understand the attraction of aligning all participant categories to 2 services (generation, and load), but inherent in this approach is an oversimplification and conflation of services and storage types, with practical impacts that will disadvantage some participants and technologies at the expense of others.
- The AEMC has previously noted the need to re-define and clarify the allocation of T/DUOS charges to customers who 'end-consume'. Whether achieved through this wholesale NER re-definition, a specific exemption for a classification that captures scheduled assets acquiring wholesale energy (for the purposes of generation), exempting any scheduled load providing system services, or amending the generator category to encompass grid-scale storage, Tesla supports further consideration of this issue.
- In the interim, if there are non-contentious elements of the rule-change (e.g. SGA's being provided full FCAS access) these could be progressed first, with additional consultation and design undertaken on network usage charges.

Any decisions that may inhibit the progress of storage projects should be avoided, and framing requirements for grid-scale storage (scheduled IRU) to pay both connection charges and T/DUOS charges is a clear example of an outcome that would perpetuate existing market distortions, provide a direct disincentive for storage assets, lead to further competitive disadvantage relative to other generators, and hinder the development of new storage required to meet the increasing demand for flexibility and provision of critical network services.

7 Underlying Principles to Support Storage Exemption

1. **NER / NEO Intent for cost allocation** – NER Chapter 6 requires tariff classes to be assigned based on the extent and nature of usage and efficient costs – with clause 6A.23.4 (b) noting TUOS *"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"*. As a scheduled bi-directional resource, grid-scale storage does not charge during peak times and can be constrained through dispatch – so NSPs do not need to increase capacity of the shared network to provide unrestricted access.

   In addition, NSPs are increasingly recognising the value of energy (e.g. virtual transmission) and non-energy services that grid storage provides (including all ancillary and essential system services, system strength, voltage stability, and resiliency) benefiting the wider system in a way that avoids network investment entirely and lowers costs for all consumers. A clear example is the introduction of System Integrity Protection Scheme (SIPS) payments – whereby NSPs / AEMO contract with transmission connected battery storage to provide network security and support increased transfer capacity. In contrast, AEMC is proposing a TUOS charge – which would severely undermine provision of this service.

   A simplified scenario assessment (below) highlights two distinct futures that could be directly influenced by the decision taken in this rule change:

	Rule Change	Future Outcome
1. Current T/DUOS Application (Allocated to customers)	**2A.** T/DUOS allocated to customers <u>& all storage</u>	Increasing spend on network infrastructure (per ISP projects) so total level of T/DUOS larger than current[1]; *but* Per AEMC draft – grid storage (as scheduled IRU) allocated full T/DUOS based on prescribed NSP service (suggesting reducing levy on end-customers) or some portion of charge through negotiation (unclear if this lowers consumer portion); *but* Much less grid-scale storage developed (due to non-cost reflective T/DUOS killing commercial viability), so non-network options not pursued, resulting in absolute value of network costs even higher than optimal ISP pathway as more poles, wires, syncons need to be built (increasing levy on end-customers) and/or renewables face more congestion (**increasing wholesale energy prices**)*
	2B. T/DUOS allocated to customers <u>(with grid-scale storage exempt)</u>	Increasing spend on network infrastructure (per ISP projects) so total level of T/DUOS larger than current*; *but* Electrification driving increasing number of loads and customers (e.g. EV fleets, commercial and industrial users) – sharing higher proportion of network costs; *and* Grid-scale storage efficiently integrated into NEM - increasingly recognised as non-network option (virtual transmission, network services, increasing network utilisation), can optimise energy flows, and avoids more expensive network upgrades, increases optionality benefits, and enables uptake of renewables (**driving wholesale costs lower**)*

   (*) Note: per AEMC's own analysis, "*TUOS charges account for a smaller portion of consumer bills than do wholesale energy costs. In 2020/2021 for example, TUOS accounted for 7.5 per cent of residential consumer bills (NEM wide average) compared with 33.7 per cent for wholesale energy costs*" (AEMC Residential electricity price trends, Final report, Dec 2020)

   This highlights that it is definitely within scope for the AEMC to consider the wider market cost impacts of T/DUOS application to grid-scale storage as a direct result of this rule change, and to quantify the consequential impact on consumers to understand whether the NEO is being fulfilled or not.

   Tesla suggests that by directly disincentivising one class of technology that can provide particular services in the most efficient and cost-effective manner (and with demonstrable cost savings for customers[2]) – just because the existing rules are unsettled and ambiguous in delineating between end-use load, customer services, and storage consumption, is not aligned with the NEO.

2. **Equity** – Scheduled grid-scale storage is not equivalent to an 'end-customer' but provides energy services and critical system security services, with more equivalence to a generator in respect to any network usage cost impacts. Storage does not fit within typical network tariff classes (residential, commercial, LV, HV etc.) and requires separate consideration. Given T/DUOS charges are not cost-

[2] www.aurecongroup.com/-/media/files/downloads-library/thought-leadership/aurecon-hornsdale-power-reserve-impact-study-2020.pdf

reflective (nor sufficiently dynamic), applying them to scheduled IRU such as grid-scale storage would effectively be a cross-subsidy to true end-customers and would not represent the actual marginal cost of the service provided. We welcome AEMC's acknowledgement of this point through the consultation.

The current NER framework contains several distortions for inverter-based technologies and does not yet fully recognise their unique capabilities and premium speed and accuracy of performance in providing a range of grid services. Battery storage in particular, is put at a competitive disadvantage relative to traditional generators. These distortions have been acknowledged and are being actively addressed through several concurrent AEMC, AER, ESB and AEMO reviews with varying implementation timeframes (e.g. Fast Frequency Response, 5-minute settlement, pro-active system strength provision).

As AEMO's response to the Options Paper noted, if AEMC is committed to a service-based approach, the more equitable option would be to "*amend the existing Generator category to better recognise and integrate grid-scale bi-directional assets"* and treat storage equivalent to other generators (i.e. with charging equivalent to auxiliary load). This recognises that scheduled, controllable assets are more akin to a generator or network supply asset with negligible cost impact (bust significant benefit) on the shared network.

3. **Market distortions –** scheduled storage responds to market signals. Applying static use of system charges (that are not cost-reflective) distorts co-optimised dispatch outcomes. T/DUOS would place a direct cost impost on grid-scale storage for providing lower FCAS services, and indirectly add to the spread required for raise or generation services (i.e. T/DUOS costs would need to be recovered through higher bid prices). This would distort the bid-stack and advantage more expensive scheduled generators that are already exempt from use of the system charges. This will inevitably lead to higher prices for consumers.

   Exempting grid-scale storage assets (scheduled IRU) from T/DUOS charges should result in fairer allocation of all charges and hence in stronger competition amongst wholesale energy and ancillary service providers, which will in turn continue to drive lower cost outcomes and incentivise new forms of flexibility. Any decision made on the allocation of T/DUOS charges should therefore consider these wider impacts of ensuring effective competition in the generation and supply of electricity.

   It is only in the AEMC's theoretically constructed edge case that storage would seek to charge coincident with peak load, as this would be economically irrational behaviour, and ignores the fundamental value of energy arbitrage (charging during low prices, discharging during peak prices). AEMO would also be able to constrain any scheduled storage through dispatch if storage operators attempt to act irrationally.

   Similarly, the edge case of storage discharging during a peak price event coincident with high wind/solar could theoretically worsen local network congestion – but it is unclear how TUOS addresses this issue, which is more in scope with transmission access reforms being undertaken by the ESB.

4. **Double paying** – unlike scheduled loads, scheduled IRU will pay full negotiated connection charges like all other generators and existing grid-connected storage (i.e. service agreements with NSPs & AEMO to fund connection assets). Therefore, if a grid-scale storage unit is seeking to connect in a 'poor' network area, this would be reflected in additional connection and system strength remediation costs to fund adequate network augmentation (over and above what standard end-use customers would be expected to pay when seeking access).

   The only electrons technically consumed by utility scale energy storage assets, is the net variance in total MWh charged from the grid, and subsequently discharged into the grid, based on round-trip efficiency losses. This is effectively equivalent to auxiliary load of thermal generators - this is also the view that has been taken by the Clean Energy Regulator in providing renewable energy target (RET) liability exemptions to grid-scale storage assets.

   It is also unclear whether negotiated use of system charges paid by scheduled IRU would decrease TUOS payments from other consumers, or whether this would only be the case if the services are prescribed. If the latter, then there is a serious double charging flaw as TUOS would be paid twice on the same electron.

5. **Competitive neutrality –** applying T/DUOS to scheduled IRU (grid-scale storage) would disadvantage these assets relative to other generators. No other electricity generators incur network usage costs to provide energy or system services. Suggesting it is a technology neutral application based on customer services ignores the exemption granted to auxiliary load for many thermal generators. The UK market regulator acknowledged this very issue as part of a process to grant storage assets an exemption to equivalent UoS charges: *"we remain of the view that storage may be at a disadvantage in comparison with generation in providing the same or similar services to other parties".*[3]

   Whilst gas plant owners may cite their funding of pipeline infrastructure through gas 'TUOS', this is not analogous, as gas plant directly drive pipeline costs, and gas molecules are not returned to the pipeline to benefit other end-customers (i.e. it is one-way flow like traditional end-use electricity load). It would also imply (falsely) that coal plant that receives its feedstock via truck should pay more to maintain all road infrastructure via a road usage charge than others. (Slightly) more analogous is line-pack or gas storage – as recognised by an AER determination[4] where users of gas storage are exempt from TUOS equivalent "cross-system" tariffs (in the best interests of all gas consumers).

   More importantly, integrating storage efficiently is fundamental to ensure a least-cost transition to a renewable energy power system with low-to-no fuel costs. Looking at how legacy technology has funded its supply-chain infrastructure is becoming increasingly irrelevant.

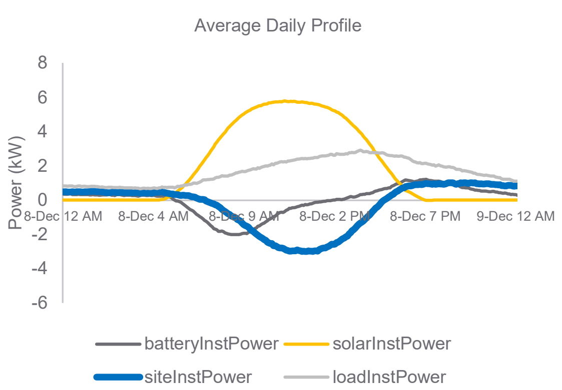
   Creating a non-level playing field is particularly problematic at this current juncture as we expect inverter-based technologies to replace the existing synchronous fleet as assets retire – both for peak energy needs, and to provide critical system services. If this rule change is adopted, these retiring assets will eventually be replaced with storage assets providing a higher quality service – but at a higher cost of delivering this high-quality service, and in less streamlined and coordinated deployment arrangements.

6. **Operating characteristics** – there are fundamental differences between the definitions, obligations and charges relevant to end-use load, market customers, and dispatchable wholesale charging of storage. Storage is not typical end-customer load (which may add to peak requirements), but is highly controllable, subject to AEMO dispatch control, with a two-way response (unlike pool pumps etc), providing a suite of network benefits from both energy and non-energy services (e.g. reactive power, FFR, frequency stability). Many services are still unvalued, and operators bear the costs (and energy losses) in providing these wider system benefits. As many NSPs have noted throughout consultation on this issue, storage should not be liable for use of system charges as they *"can be distinguished from other loads, including scheduled loads, because their services are primarily energy supply chain services provided for the benefit of energy consumers"* (AusNet, 2018).

   Grid-scale storage is also fundamentally different to residential, behind-the-meter storage in the frequency and breadth of services provided, as illustrated below:

Residential battery storage

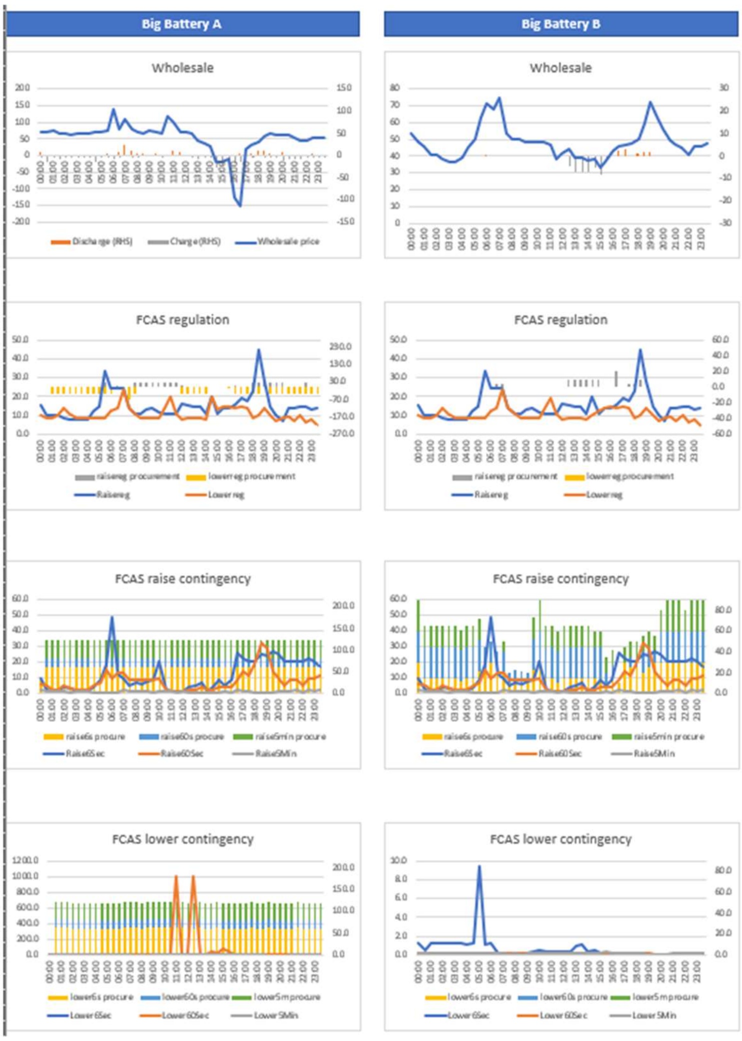
(optimised to minimise behind the meter consumption)



[3] https://www.ofgem.gov.uk/sites/default/files/docs/2020/05/cmp281_d.pdf
[4] aer.gov.au/system/files/AER%20-%20Attachment%2010%20-%20Reference%20tariff%20setting%20-%20November%202017.pdf

Grid-scale battery storage

(dispatched to market price signals and providing system services)



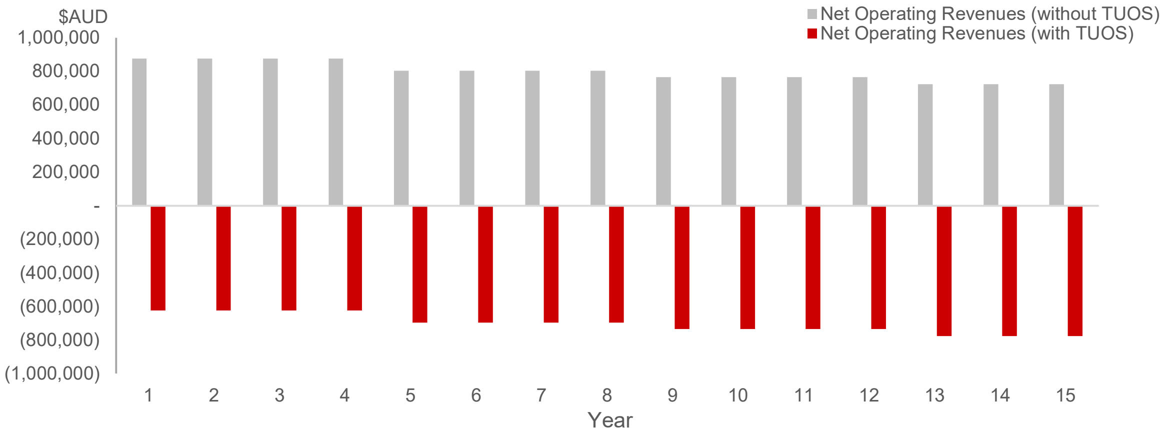
Grid-scale storage provides network support benefits to the NEM in several characteristic ways that further highlights the inappropriateness of applying T/DUOS charges:

- Grid storage provides network support by managing the impacts of network congestion. This is particularly so during periods of high wind and low network load, where storage can reduce the need for wind curtailment by storing excess, near zero marginal cost generation for use later. Applying T/DUOS would disincentivise this otherwise efficient behaviour, decrease network utilisation, and drive higher wholesale energy prices for consumers.
- Grid storage assets are often dispatched to charge and provide critical system security services. No generator is ever required to pay T/DUOS charges, let alone when it is dispatched to provide a system service. The ability to quickly and accurately switch from discharge to charge to follow AEMO signals is show in the big battery operating profiles above, the benefits of which have been well documented through independent reports by AEMO and Aurecon on the first 2 years of operation of Hornsdale Power Reserve[5]. Applying T/DUOS for an AEMO instructed dispatch to charge would result in a strong disincentive to providing critical and essential system services.
- Grid-scale battery storage systems are capable of absorbing and supplying reacting power to support network voltage which can offset the need for infrastructure augmentation. These services are provided by the asset operator who bears the costs of the losses associated with providing this voltage support.

[5] https://www.aurecongroup.com/markets/energy/hornsdale-power-reserve-impact-study

7. **Investment distortions** – a grid-scale storage asset's business model is built around serving customers, as is the case for other generators. With ongoing reforms and existing market barriers still being addressed, the commercial case for storage is still evolving and is highly price sensitive. Embedding a framework that assumes T/DUOS charges will apply to scheduled IRU, effectively kills the commercial viability of new grid storage projects:

Indicative cashflow of grid-scale battery storage project with TUOS impacts



Increasing barriers and adding inefficient costs will delay uptake and lead to overall higher costs to consumers. Relying on negotiated outcomes with NSPs preserves uncertainty and any risk of a cost impost could drive perverse decisions for grid-scale storage (registering as scheduled IRU) to locate in service areas with more favourable NSP charges (see section below).

Further, applying T/DUOS to grid storage providing network applications (e.g. SIPS) would erase their value as a non-network option (distorting commercial and regulatory outcomes), and drive unnecessary investment in traditional network expenditure, ultimately adding higher T/DUOS charges to customers.

From a system planning perspective, there is an established consensus of the need to promote the uptake of storage in the NEM to ensure continued safe, secure and reliable operation over the coming decades, as well as promote efficient investment infrastructure in the interests of consumers. As AEMO state in its Integrated System Plan: *"There is a growing need for energy storage over the next 20 years to increase the flexibility and reliability of supply"*. However, with lower or slower storage uptake, customers would face the consequences of less competition in wholesale energy and FCAS markets, increasing customer bills even further. As noted in point (1) above, this creates a fundamental misalignment with the NEO.

Why negotiating on T/DUOS charges with NSPs fails to adequately address the issue

Ongoing charges for system and network use is a key operational consideration for project developers looking to build new hybrid facilities, retrofit storage onto an established wind or solar facility, or for grid-connected storage assets to be viable in providing market and network support services.

Throughout the draft determination consultation, AEMC has highlighted its intention for IRU such as scheduled storage assets to continue to be able to negotiate both services and commensurate network charges directly with NSPs. We acknowledge the AEMC's draft view that maintaining tiers of prescribed and non-prescribed (negotiated) services may provide flexibility for lower (or zero) T/DUOS charges.

However, given the investment in time (3+ years in design, another 18 months to implement), costs (up to $30m for AEMO to implement) and resourcing impacts on AEMO and industry (already stretched with reforms) it is a significant missed opportunity to not address one of the key issues driving the original rule change. **Clarity is critical for investment certainty.** Relying on negotiated outcomes with NSPs preserves existing uncertainties for investors, reinforces informational and commercial asymmetries in favour of NSPs, and is not a good outcome to leave un-addressed in the final determination:

- There is no guarantee that NSPs agreeing to T/DUOS exemptions in principle now, do not change their approach in practice, or apply new assessments to existing projects based on change in law provisions contained in connection agreements
- Even the potential threat of T/DUOS adds a project cost premium that may ultimately drive perverse decisions for grid-scale storage to locate in areas with greater perceived certainty, adds risk to existing storage projects, and given the significant financial impact (up to $10m per 100MW depending on locational charges) can delay or terminate new projects entirely
- In practice, it is unclear at what point a project under development would be granted confirmation of what charges do or do not apply to scheduled IRU, nor is it clear how consistent this process would be for different projects, regulatory periods, or NSPs – creating further uncertainty and risk for new projects
- It is unclear whether negotiated outcomes resulting in T/DUOS charges actually reduce the level of T/DUOS paid by other customers, or if this would only be the case for fully prescribed services and costs
- Prolonging uncertainty on T/DUOS not only requires AER monitoring to limit NSPs favouring NSP-owned assets (as AEMC outlines), but also introduces the risk that any grid-scale storage asset contracted to provide network services for an NSP may negotiate more favourable outcomes than non-contracted assets (that may still provide comparable network or essential system services via market mechanisms)
- To date, NSPs have consistently struggled (or face barriers) to get clarity on how to define, assess and quantify the benefits of non-network assets such as storage – as evidenced through the AER's RIT-T/Ds and Tariff Structure Statement processes: *"Where a battery is owned by another party, all distributors proposed a tariff exemption where that asset is provided to the 'net benefit' of network customers. However, the proposals were silent as to how distributors would define or measure 'net benefit' "*[6]
- The commercial case for storage projects is still evolving (as market rules evolve in parallel to recognise and value two-way, dynamic, and flexible services). Increasing barriers, prolonging uncertainty, and adding inefficient costs will directly stymie uptake. This will create outcomes in direct conflict with the NEO – constraining grid-scale storage uptake relative to the least-cost development path and effectively cross-subsidising end-consumers (up to 20GW by 2040s as per AEMO's 2020 step change scenario)
- As thermal generators retire, the energy system will transition to renewables and storage. This transition is inevitable, and already accelerating. From a network usage charge perspective, exemptions will have no negative impact on end-customers (most likely a positive one) - thermal plants (no T/DUOS) retire and are replaced with grid-scale storage (should have no T/DOUS).

[6] www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20AusNet%20Services%20distribution%20determination%202021%E2%80%9326%20-%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20April%202021.pdf

Importance of clarity for networks

Under the current NER framework, grid-scale battery storage (larger than 5MW) is required to register as both a market customer and a scheduled generator. As noted by the AEMC, this has the following implications:

- Utility scale battery storage is required to pay network connection costs, as required by all generators looking to connect into the national electricity market (NEM); and
- Under Chapter 6A of the NER, the load side of a grid-scale battery energy storage asset may also be required to pay T/DUOS charges for use of the network based on the relevant pricing principles developed by individual NSPs.

In practice, grid-scale battery storage assets are considered on a case-by-case basis in respect of whether energy storage resources will be required to pay T/DUOS charges or not. This lack of consistency makes it difficult for developers and NSPs to accurately plan project and network expenditure and assess individual project feasibility. The current uncertainty in respect of this issue has caused confusion and uncertainty for many energy market participants and NSPs.

Should the AEMC preserve ambiguities in the framework that result in scheduled IRU being treated equivalent to all end-use load and leave it up to individual NSPs discretion whether grid-scale storage assets pay T/DUOS charges, this could undermine these projects from going ahead. This would also ignore grid storage assets unique characteristics beyond a standard end-customer load - such as being controllable and providing grid and frequency stabilisation services.

Discussions with TNSPs indicate unanimous support for creating clarity in the rules for not applying TUOS to grid-scale storage given the network benefits provided (i.e. charging occurs during low load periods, discharging during low generation periods – thereby maximising utilisation of the network).

Per investment certainty comments above, TNSPs would also likely have to navigate additional AER compliance guidelines or manage additional oversight to ensure inconsistencies between TUOS charges do not arise between systems with direct network ownership or contractual links and systems without.

All TNSPs have previously outlined their clear preference for TUOS exemptions being made clear in the rules (e.g. as part of COGATI and AEMO consultations through 2018-2020). TNSPs note that unlike loads, there is zero risk of scheduled grid-scale storage having a negative impact on the network (given it would be economically irrational to charge at peak periods, and even if storage units were to try, it could still be constrained off through AEMO dispatch).

Accordingly, leaving this to individual negotiation with connecting parties is providing unnecessary flexibility (and is seen as an additional administrative burden on NSP pricing teams having to negotiate every application). Instead, a definitive exemption position for the proposed scheduled IRU provides the required certainty.

Industry and Market Body Consensus on exemption certainty

Whilst we note stakeholder consensus is not a direct driver of AEMC's decision making (nor should it be), it is still important to recognise that a near universal local industry and market body consensus has been held on this issue since it was first explored as part of the AEMC's 2018 Coordination of Generation and Transmission Investment (COGATI) consultation. Our preferred position for exempting grid-scale storage from UoS charges is also being progressed with increasing international regulatory recognition of the benefits.

Whilst the AEMC may no longer be proposing a technology specific 'storage' category, defining scheduled /non-scheduled IRU in the rules acknowledges the nuances of bi-directional assets and the current challenges with capturing characteristics within standard generator or customer definitions. As such, this approach still aligns with AEMO's rule proposal and its TUOS pricing methodology for Victoria[7], and consensus of feedback

[7] aer.gov.au/system/files/AEMO%20TUOS%20Pricing%20Methodology%20Consultation%20Paper%20-%20November%202020.pdf

(including from AER and all TNSPs) received over the past 3 years, which proposed TUOS exemptions for grid-scale storage, as captured through COGATI[8] and AEMO's Emerging Generation and Energy Storage consultation, and reflected in the AEMC's own views: [9]

- *"AEMO proposes that an ESS [energy storage system] that is a scheduled resource and can be constrained off should not be required to pay TUoS charges"*
- The AEMC 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."*
- *"The AER accepted ElectraNet's position on ESCRI and agreed that TUOS charges would not be payable at the connection point under the NER."*
- Electricity Networks Australia: *"Under the current transmission pricing arrangements, if transmission connected scale batteries are centrally dispatched and cannot drive transmission network augmentation, transmission use of system charges should not be levied when the batteries are charging"*

TUOS & DUOS equivalence

To be clear, exemptions to use of system charges for scheduled IRU such as storage should be valid for both transmission and distribution grid-connected assets. Applying a consistent exemption across both TUOS and DUOS exposed assets is vital to optimising storage operating in the distribution layer, which in turn will include beneficial network services that cannot be provided from the transmission layer. Not doing so may also lead to distortionary outcomes where grid-scale storage become concentrated at the transmission level, reducing the value of services at the distribution layer.

Internationally exemption precedents

There is a growing body of international experience that can be drawn upon to support the position of granting a storage exemption from TUOS and DUOS charges, including as part of a separate market classification.

As early as 2016, the UK Government recognised traditional network charging allocations as a barrier to storage technologies: *"storage can be charged as an end user of electricity (even when this electricity is exported and used a second time). We are looking to address this double counting"* and in particular highlighting it as *"an issue which we believe could have an impact on the competitiveness of storage"*.

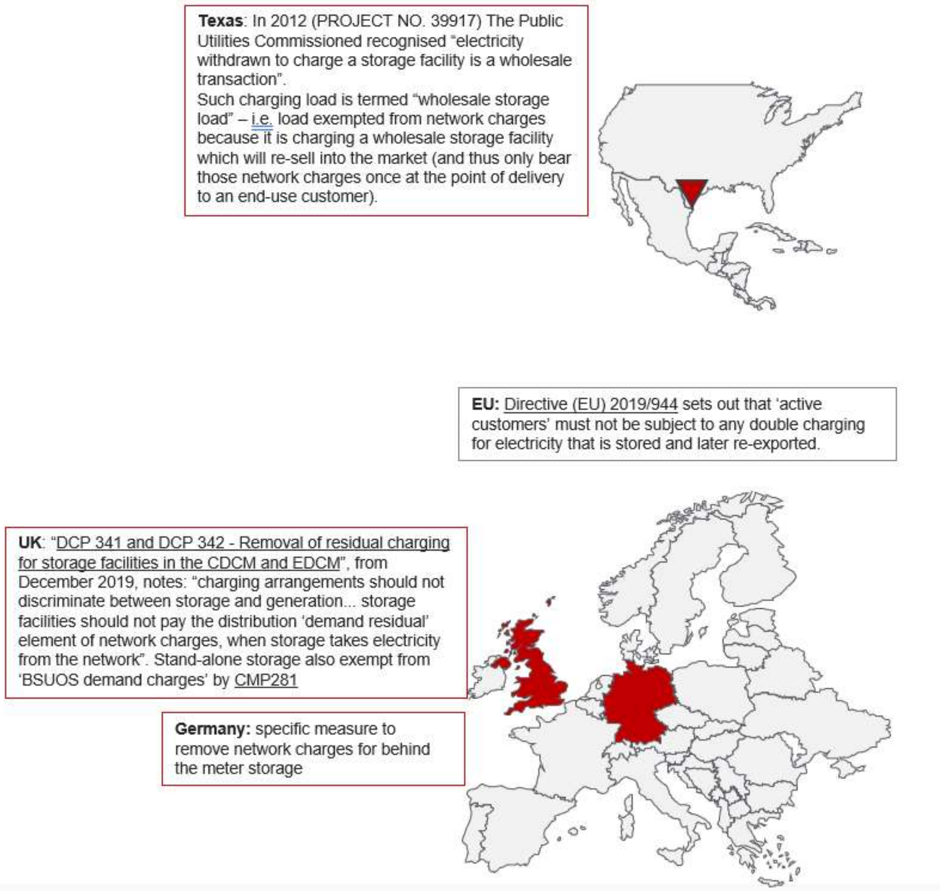
In regulatory reforms since, a clear exemption approach has now been confirmed in the EU and UK market rules (enshrined via the Clean Energy Package in Dec 2020) – where *"active customers that own an energy storage facility are not subject to any double charges, including network charges, for stored electricity".* This follows recognition that applying a narrow interpretation of what constitutes a load and customer service to also include storage would result in severe market distortions and unnecessary inefficiencies.

A similar conclusion was made by the Public Utilities Commission of ERCOT in Texas, which is the most comparable US jurisdiction to the energy-only market structures of the NEM, and which now recognises storage consumption (at a wholesale level) as a fundamentally different service to end-use customer load.

Again, whilst not a direct decision driver for the AEMC, these decisions by other jurisdiction's regulators and rule makers to codify exemptions for storage in their local markets may at least demonstrate an independent signal on how others are viewing technology neutrality and economic efficiency arguments and ensuring practical outcomes are achieved in the long-term interests of their consumers.

A summary of these positions is captured in the figure below.

[8] https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf
[9] https://aemo.com.au/en/initiatives/trials-and-initiatives/emerging-generation-and-energy-storage-eges-grid-scale



Issue B: Retailer Reliability Obligation (RRO) liabilities unintentionally capture auxiliary load and round-trip efficiency losses for storage – clear exemptions should be applied

Recognising the intent of the RRO is to ensure adequate reliability during peak demand it is clear that grid-scale storage facilities should be treated as an 'asset' not a liability.

As the RRO is currently designed, customers with gross load over 10GWh per year become liable entities. Introducing a new, combined registration classification category (scheduled IRU), improves on the current situation in allowing only aggregate load (net of generation) to be included in the 10GWh threshold assessment. However, battery storage units over ~200MWh (for example) could still be liable due to their round-trip losses (10 – 15%).

It appears this was a simple oversight in the scheme design, with its objective to ensure large retailers can demonstrate financial contracts with generation supply during forecast reliability events. It is highly non-sensical to enforce those same liabilities on large-scale storage assets (which are predominately a form of supply or network infrastructure as outlined above) and potentially require equivalent demonstration of financial contracts with other generating units. This is a clearly not aligned with the objectives of the RRO (to ensure reliability during forecast peak periods) and would unfairly add unnecessary costs and risks to owners and operators of storage assets.

We note that in practice, the impact of the RRO may be limited by the flexibility of storage to choose not to charge during any reliability events – but uncertainty remains on whether this would preclude providing non-energy services (essential system services) that rely on drawing energy from the grid (e.g. FCAS lower contingency or regulation services) – that, whilst rare, have still historically been provided during certain high price / demand intervals, or may be contractually required, irrespective of energy reserve conditions.

Rather than defer to a later stage AER or ESB review, this rule change has another opportunity to provide much needed market clarity and certainty for an entire class of registering participants.

Additional Issues: Ensuring Dispatch Flexibility

As per the stated objectives of the rule change, the AEMC's starting principle should be to improve on the status quo, and this includes improving the operational efficiency of storage through the dispatch processes. The two roles of storage (charging and discharging) leverage complex optimisation algorithms to ensure maximium effieciency for operators and the wider market. This optimisation values flexibilty and optionality (noting storage bidding is ultimately an opportunity cost trade-off), and strategies for load, generation and ancillary services can be assessed both independently and in parallel. As such, it would be helpful for the AEMC to detail how current bidding flexibilities will be maintained under the combined DUID approach, for example where conditional bids can be made depending on market signals (e.g. bidding regulation FCAS and load concurrently).

Additional items to consider and detail include how 'availability' flags will be managed (noting storage can be available to charge but not discharge when empty, and vice-versa when full) – noting the costs of needing to duplicate these elements even under a single DUID approach. Further, current storage facilities can maximise dispatch efficiency by self managing any potential overcommittments and state of charge bounds, rather than being forced to represent itself as unavailable based on future energy availability requirements outlined in the draft rules. The proposal, as drafted, represents less flexibility than the status quo, and would introduce unecessary inefficiency into the dispatch process.

Supported changes

Not withstanding the above commentary, and Tesla's significant concerns with how the Rule Change has been progressed, there are elements of the Draft Determination that Tesla supports. We would recommend fast-tracking the following reforms as important steps forward for the industry:

- Tesla supports, in-principle, aggregated small storage assets providing FCAS. If there is a way to introduce an IRP classification to replace the existing MSGA classification, Tesla is supportive of doing so.
- Tesla very much supports the consolidation of clauses in Chapter 2 that relate to ancillary services. Defining an umbrella term of "ancillary services unit" removes a number of definitional issues related to assets being considerd "ancillary services load" or "ancillary services generating units" and will create a very positive outcome for a range of new business models, such as virtual power plants (VPPs). We recommend progressing this rule change as a matter of priority and implementing it as soon as reasonably possible. We note that given this is a only a definitional issue and will not result in process or system changes at AEMO, it can be implemented immediately following the Final Rule – rather than in 18 months.

Appendix A: Summary of feedback on the AEMC's draft determination TUOS views and proposed rationales

#	AEMC Rationale	Response
1	NER are clear that **TUOS applies to customers** (and not generators), and storage charges from the grid like other load customers. Without defining storage in NER, rule maintains **service-based approach** (generation / load). Out-of-scope to change this.	Storage neither consume nor produces electrons. It stores to improve network utilisation and increase market competition. For grid-scale storage, this is a different wholesale service – now recognised by rules in UK, EU and Texas – and obligations and charges should reflect this. If paying TUOS (or a portion), storage (or scheduled IRU) would still not receive equivalent 'firm' access level of other customers and would receive lower level licence conditions for reliability and availability of charging. Grid-scale storage is a scheduled asset (can be constrained in dispatch), not a true end-consumer and does not contribute to network costs like load. This should be the target scope for a rule looking to integrate storage efficiently. Exemption issue raised and supported by generators, AEMO, TNSPs through 3+ year consultation. AEMC's preliminary position also supported this view.
2	Exempting storage is **not technology neutral** (other loads pay TUOS and generators pay for fuel transport) and is more policy than economic efficiency	NER applies T/DUOS to users that drive network spend to meet max load (clause 6A.23.4 (b)). It is economically irrational for storage to charge coincident with peak (and it can be constrained if it tries). Current TUOS is not cost-reflective (would be substantial for storage). Forces scheduled, grid-scale storage to be equivalent to all end-use load. Applying TUOS on grid-scale storage (scheduled IRU) would disadvantage it, compared to other generators, and does not represent the actual marginal cost of the service provided. Grid-scale storage would be paying additional costs, despite having access to the same revenue streams and same or similar services (e.g. non-firm grid access). Excluding scheduled IRU from paying TUOS charges is not 'picking winners', it is recognising unique characteristics of different technologies (e.g. as per the need for a semi-scheduled classification for solar and wind) and minimising further distortions. Fuel-powered generators are consumers of that fuel (and UoS charges are very minor). TUOS for grid-scale electricity storage would be substantial. Gas storage is exempt from cross-system pipeline tariffs. Wind & Solar do not pay TUOS..
3	Storage might not be 'end-user' but it still uses the grid. Exempting storage would be a **subsidy** for one asset that results in **higher costs for other consumers**.	All assets use the grid. The lowest cost outcome for consumers is wind/solar + storage to supply end-customer loads. Increasing barriers to storage uptake increases system cost (e.g. prevents non-network solutions) and raises wholesale energy price. Applying T/DUOS to scheduled IRU cross-subsidises end-use load's fair share. T/DUOS exemption provides net benefit to consumers as grid-scale storage defers additional network investment (that would add to T/DUOS). Transparent that all scheduled, grid-sacle, non end-consuming assets are treated like generators. It is also unclear whether negotiated T/DUOS charges reduce the collection of T/DUOS from other customers (or if this is only the case for prescrbied services).
4	May **need to charge some storage** in certain locations where it has a negative impact	TNSPs note that unlike loads, there is zero risk of scheduled, grid-scale storage having a negative impact on the network (given it would be economically irrational to charge at peak periods, and even if it were to, can be constrained in AEMO dispatch). AEMC always can manage this theoretical risk by allowing TNSPs to apply for non-zero application of T/DUOS charges where they can demonstrate any projects to have such negative impact.
5	Rules designed to provide flexibility to **negotiate** different outcomes [i.e. level and cost of service]	Leaving this to individual negotiation with connecting parties is providing unnecessary flexibility, increases uncertainty (and therefore risk and cost) on all parties, opens risk of inconsistency across juristictions, across projects, and across NSPs, and adds administrative burden on NSP pricing teams having to negotiate every application. Instead, a definitive exemption position provides required certainty.
6	Rule **provides certainty and transparency** – (T/DUOS applies). All existing storage being granted exemption should provide certainty on NSP decisions	No guarantee that NSPs agreeing to T/DUOS exemptions in principle now, do not change their approach. May drive perverse decisions for grid-scale storage to locate in areas with greater perceived certainty and add risk premium for storage development. This can delay or terminate new projects entirely. AEMC can look at ensuring greater transparency and certainty is applied – e.g. by placing burden of proof on NSPs to appyl a non-zero UoS charge to projects, and otherwise base-case assumption should be exemption.

7	Network responsibility to design and allocate **cost-reflective tariffs** for customers	TNSPs all want exemption clarity in NER. They recognise grid-scale storage as benefit to network (increases utilisation by charging during min demand, discharging during peak) + voltage, frequency services etc. Grid storage pays for augmentation required. So arguably a tax for storage to pay TUOS (much greater than incremental cost as TUOS not cost reflective). Participants need certainty on exemption until cost-reflective T/DOUS charges are implemented for all generators and loads (if that is the end-outcome being sought by AEMC and ESB reforms).
8	Some participants want prescribed services and are **willing to pay** for TUOS	Projects may be willing to pay charges in exchange for services. However no commercial grid-sacle storage project can afford prescribed TUOS charges. It is unclear whether AEMC is suggesting that paying TUOS would provide scheduled IRU 'firm access' equivalent to other load, and reduce connection requirements. An approach that allows projects to opt-in to paying is fundementally different to the current propsal to force proponents to justify not paying TUOS. Order of magnitude must also be considered – the full cost of T/DUOS (as based on current non-cost reflective UoS customer charges) would likely kill the commercial case for all future grid-scale storage projects. It is not logical to suggest any project would agree to a payment that renders their project unviable.
9	**AER would play a role** in making sure TNSPs do not unfairly favour network-owned batteries	Adds unecesary governance burden (where information asymmsetry rests with NSPs) and still leaves the risk that any storage contracted to provide network services for the NSP may negotiate more favourable outcomes than non-contracted assets .
10	Need to be **consistent** with how we treat all loads. Unclear wher the line would then be drawn (e.g. for other loads)	Line can be drawn for scheduled grid-scale storage, A scheduled IRU such as grid-scale storage is not typical end-customer load (which may add to peak requirements), but is highly controllable, subject to AEMO dispatch control, with millisecond two-way response (unlike pool pumps etc), providing a suite of network benefits from both energy and non-energy services (e.g. reactive power, FFR, frequency stability). Exemption could cover all scheduled, non end-use load that participates in wholesale trading (this is the approach taken in UK, EU and ERCOT). We note similar lines have been drawn to carve out auxilary loads from generating stations being liable for TUOS, RRO, RET liabilities etc.
11	Not AEMC's role to support one technology over another – even if storage uptake slows if 'pays fair share'	Applying static use of system charges (that are not cost-reflective) is not a fair share, distorts co-optimised dispatch outcomes and disadvantages one technology relative to others (that are exempt). Rule change scope is to consider 'efficient integration of storage' - AEMC must consider system-wide impacts of increasing cost / delaying uptake of storage and externalities as a direct result of rules made/not made. This has direct impacts on the long-term interests of consumers – and preserving T/DUOS unceratinty is misaligned with the NEO. These considerations supported AER's justification to exempt gas storage from paying transmission pipeline usage tariffs in Victoria.
12	Rules are not made to support majority view but to **align with NEO** and support efficient market outcomes	Constraining grid-scale storage uptake relative to the least-cost development path in the short term cross-subsidises end-consumers at the expense of otherwise efficient deployment of storage at scale, and in the long-term increases costs for all consumers. As system transitions, grid-scale storage exemptions have no negative impact on end-customer loads (most likely a positive one): thermal plant (not paying TUOS) retire and replaced with solar/wind + storage. In parallel, electrification driving increasing number of loads and customers (e.g. EV fleets, commercial and industrial users) – sharing higher proportion of network costs (some of which can be deferred or avoided through deployment of lower cost, higher benefit non-network options including storage).
13	New storage may **worsen congestion** and lead to inefficient locational decisions	This may only be the case in theory – and congestion is more relevant to access reforms being progressed by the ESB. It is not clear how TUOS would incentivise charging to relief congestion, nor how it would directly relate to locational decisions. TNSPs themselves view storage as a benefit to the grid. Relying on negotiated outcomes with NSPs will distort locations based on TUOS application. Grid-scale storage provides network services (SIPS, voltage, system strength), that enhance security and reliability – unlike other load. Leaving it to negotiation may drive grid storage to follow exemption certainty over network need or location benefits.

Appendix B: Addressing gas ‘use of pipeline’ equivalence

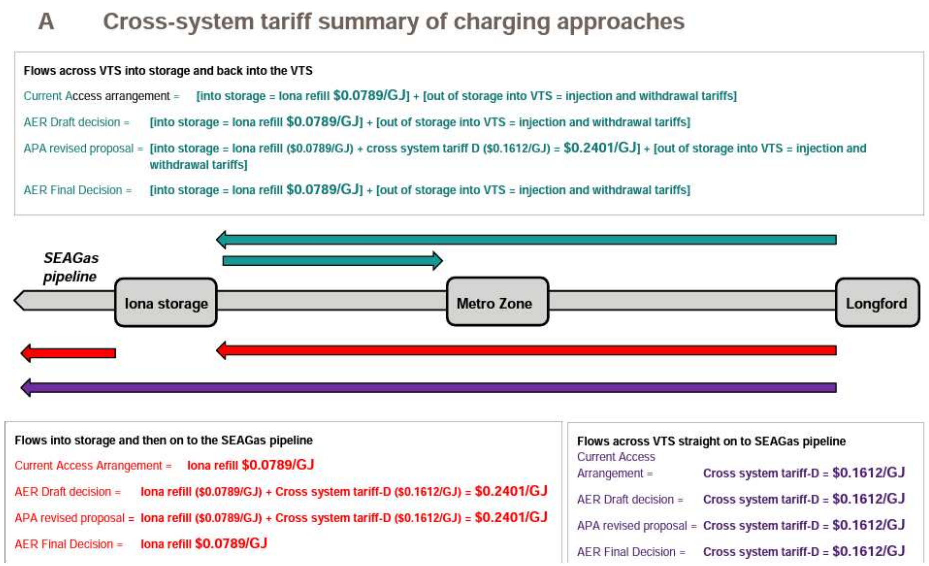
In general – gas is too different to directly compare usage charges. E.g. Transport rights are point to point and secured on that basis by shippers – very different to our blended power transmission charges. At a high level, we note:

- TUOS for electricity is not cost reflective and not equally or fairly applied to all users
- Proportion of network usage costs for electricity is much greater than what gas plants would pay for pipeline transport costs
- Wind and solar don’t pay fuel cost - this is a feature of competitive markets that is supporting transition to renewables - storage is an enabler of this
- Coal plants pay for coal supply, in the same way that batteries pay for electron supply. Coal plants do not pay for truck road usage and maintenance over and above what other road users pay. Gas storage operators do not pay for cross pipeline tariffs as evidenced by the following AER decision.

AER Final decision: APA VTS Australia Gas access arrangement 2018 to 2022 Attachment 10 – Reference tariff setting[10]

A recent decision by the AER highlights the complexities in assigning pipeline charges & tariffs to storage assets (noting storage is typically a regulated asset and users are responsible for securing transport rights):

- *“Any extra **costs recovered (and therefore tariffs paid) for use across the [Victorian transmission system] VTS could discourage the efficient filling of gas into Iona storage from** Port Campbell. A similar concern is also relevant to APA’s revised proposal. The charging of the cross-system tariff in addition to the refill tariff could undermine the incentive to refill storage capacity in off-peak seasons as was initially intended.*
- *Given recent gas market dynamics and wholesale gas price increases, we **consider that the near 200 per cent increases** that would result from APA’s revised proposal **would not be in the interests of Victorian gas users**.*
- *While the user pay principle is more directly applied under APA’s revised proposal, we **consider in this case the application of user pays will not lead to material improvements to the efficient use and investment of the Victorian transmission system or the Iona underground gas storage facility**.*
- *The volumes of gas shipped across the VTS from Longford and Culcairn into storage and subsequently to South Australia is still small and volatile. Removing the subsidy associated with these small volumes would result in significant price increases for other users. Therefore, we consider continuation of the current 2013–17 access arrangement pricing methodology **best balances the user pays principle, use of Iona storage and future price impacts.”***



[10] www.aer.gov.au/system/files/AER%20-%20Attachment%2010%20-%20Reference%20tariff%20setting%20-%20November%202017.pdf