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To AEMC
Reference Rule change request
Submitted via email
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Subject Rule Change Request – Settlement under Low Operational Demand

Overview:

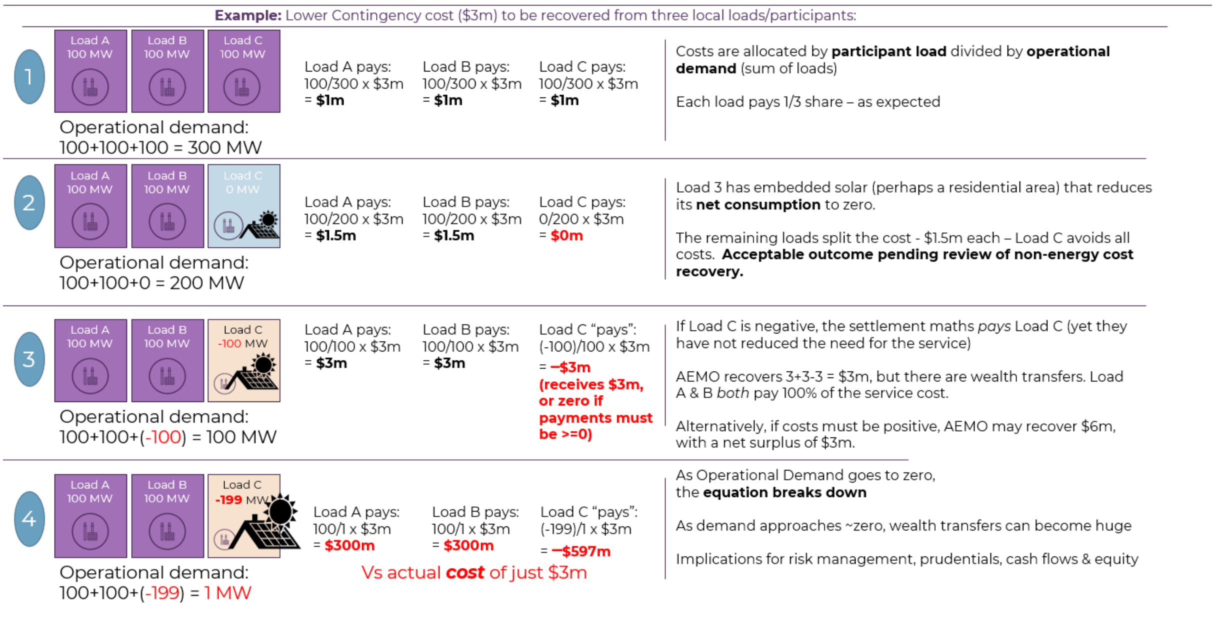
Infigen delivers reliable energy to customers through a portfolio of renewable and firming assets across New South Wales, South Australia, Victoria and Western Australia. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

Infigen is a customer-centric retailer; we are committed to representing the interests of our customers and providing transparent advice on the energy market. In consultation with industry and consumer groups, and building on issues identified by AEMO in October 2020[1], we have identified a critical risk to consumers, particularly in South Australia.

Due to market rules that did not consider the possibility of bi-directional resources, there is a risk that a subset of South Australian customers[2] could be charged costs that are many times higher than the costs incurred by AEMO in procuring these services. Specifically, as net operational demand approaches zero, there is a risk that the remaining customers could be exposed to non-energy costs in excess of $1,000,000/MWh; an example infographic is shown in Figure 1. Furthermore, when operational demand reaches zero (or goes negative), AEMO's system will not be able to recover the required costs under the NER. AEMO is now projecting this could occur by spring of this year.

[1] https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/nem-settlement-under-zero/nem-settlement-under-zero-and-negative-regional-demand-conditions.pdf?la=en
[2] And potentially customers in other regions in the future

Figure 1 Example of settlement distortion



This may lead to material cost impacts on customers, and would distort the energy market with impacts on reliability and security, and may ultimately lead to a breakdown of AEMO systems. This would threaten the efficient administration of the NEM, and discriminate in particular against large customers.

Infigen is proposing a flooring mechanism to remove the distortionary, non-physical cost recovery by excluding exporting (negative load) Market Customers from cost recovery calculations. This will ensure customers pay no more than a pro-rata share of costs while more comprehensive reforms to non-energy cost recovery are progressed through AEMO's Integrating Energy Storage rule change, and remove the near-term risk of zero denominators in settlement equations.

Based on AEMO's most recent advice, these issues could occur as soon as spring 2021. We therefore request the AEMC consider this as an **expedited (urgent) rule change**, allowing time for necessary changes to be made as soon as

1. Problem statement

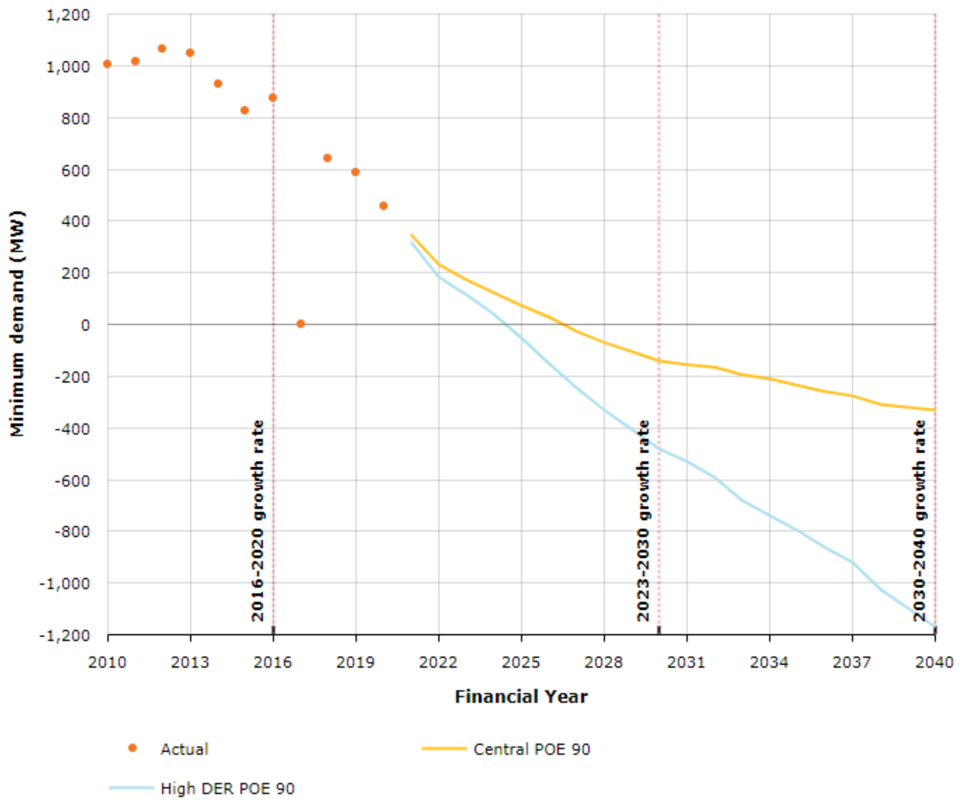
1.1 Low or zero operational demand

The growth of embedded generation (rooftop solar) in South Australia has led to a significant reduction in operational demand.

In the 2020 ESOO, projected minimum demand under the high DER scenario (90% POE) in South Australia was ~200 MW in FY2022, down from 300 MW in FY21 (against a projected 320-348 MW in the ESOO). In October 2020, AEMO subsequently revised projections for Cal2021 to as low as 150 MW. AEMO has subsequently undertaken further analysis that indicates that zero (or negative) operational demand could be observed in South Australia from September 2021[3].

We note that, while data is not publicly available, low or negative operational demand will involve some Market Customers having negative loads, to offset the remaining Market Customers with positive loads. This has significant impacts on the NEM's settlement systems.

Figure 2 2020 ESOO minimum demand projection (shoulder periods) in South Australia (P90)



1.2 NEM settlement

This section provides a qualitative overview of the key issues. Specific clauses and proposed fixes of the NER are included in Section 2.

Non-energy costs that are to be recovered from Market Customers in a region are generally allocated to Market Customers according to the formula:

$$\text{Allocated cost to a Market Customer} = \text{Regional service cost} \times \frac{\text{Market Customer's AGE}}{\sum_{\text{region}} AGE}$$

[3] Section 2.2, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/nem-settlement-under-zero/nem-settlement-under-zero-and-negative-regional-demand-conditions.pdf?la=en

The Adjusted Gross Energy (AGE) for each customer is defined in the relevant clauses, but is effectively the net consumption of that Market Customer for the relevant trading interval (i.e., the sum of the Market Customer's energy at each connection point which the Market Customer is financially responsible). The denominator, the sum of the AGE, is effectively the regional operational demand.

To determine the regional service cost, global services (such as NEM-wide lower FCAS volumes) are allocated to the region pro-rata with operational demand[4]. When operational demand is low, the allocated cost will also be low, but non-zero. It is not obvious how costs would be allocated to a region with negative operational demand.

Services such as directions and local lower FCAS requirements can be procured and recovered on a regional basis, with costs to be recovered from Market Customers in that region. These costs occur particularly when regions are islanded or at risk of islanding, such that local resources must be procured.

This leads to three distinct problems.

1.3 Settlement equation fails with zero or negative operational demand

The above equation cannot be evaluated when the regional demand ($\sum_{region} AGE$) is zero, due to a "divide by zero" error. This means that at best AEMO will be unable to allocate non-energy costs for that trading interval and, at worst, some of AEMO's settlement systems and downstream processes may fail. The NER provides no alternative methodology for allocating settlements, leaving AEMO unable to fulfill their broader obligations under the NER.

When Operational Demand is negative, the mathematical sign of costs will be reversed and will be inconsistent with the intent of the rules. This would have the opposite effect to the issues discussed in Section 2.5 below – loads would be *paid* for the non-energy services that they consume, creating an incentive to increase demand.

We consider this an **urgent issue.**

1.4 Increased burden on non-exporting customers

As the operational demand reduces in a region, the remaining loads pay a higher share of system services, despite native demand remaining comparatively constant. The equity concerns have been previously identified, and non-energy cost recovery from bidirectional resources is being addressed in the Integrating Energy Storage rule change proposed by AEMO.

While it is important to address this, we do not consider this an urgent issue requiring attention in this rule change.

[4] For example, 3.15.6A(g)(1)-(3)

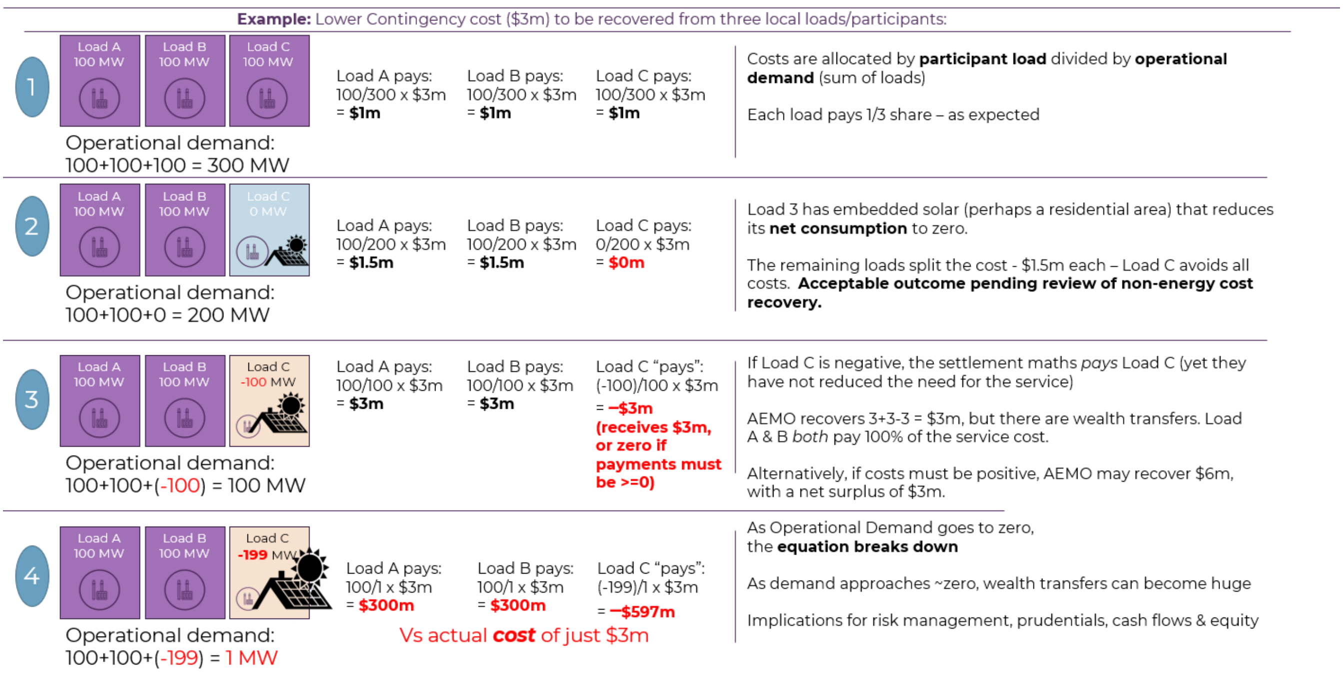
1.5 Overprocurement of costs at low operational demand

In order for the operational demand to approach zero, it is highly likely that some Market Customers will have negative loads (i.e., be net exporters – for example, large residential retailers) while other Market Customers will remain positive (for example, direct connected industrial loads or specialized retailers).

Figure 2 provides a simplified example of a region with three Market Customers (Loads A, B, and C, each initially 100 MW), with $3m in local non-energy costs to be recovered based on a share of operational demand[5]. Case 1 shows the traditional functioning of settlement, with costs allocated pro-rata, and each customer paying $1m. In Case (2), Load C develops embedded generation that drops its consumption to 0 MW – now each remaining load will pay half the service cost ($1.5m each). Both of these represent a reasonable interpretation of the intent of the Rules.

However, in case (3), if Load C exports 100 MW, now the operational demand will be only 100 MW (100+100+(-100)), and Load A and B will each pay 100/100=100% share of the costs. That is, *each* load will pay $3m for a total of $6m cost recovery for a $3m service. Load C will either be *paid* $3m (= (-100)/100 x $3m = –$3m) or will not be paid (depending on the specific service and clause in the NER) such that AEMO will receive a $3m settlement surplus.

Figure 3 Example of settlement distortion



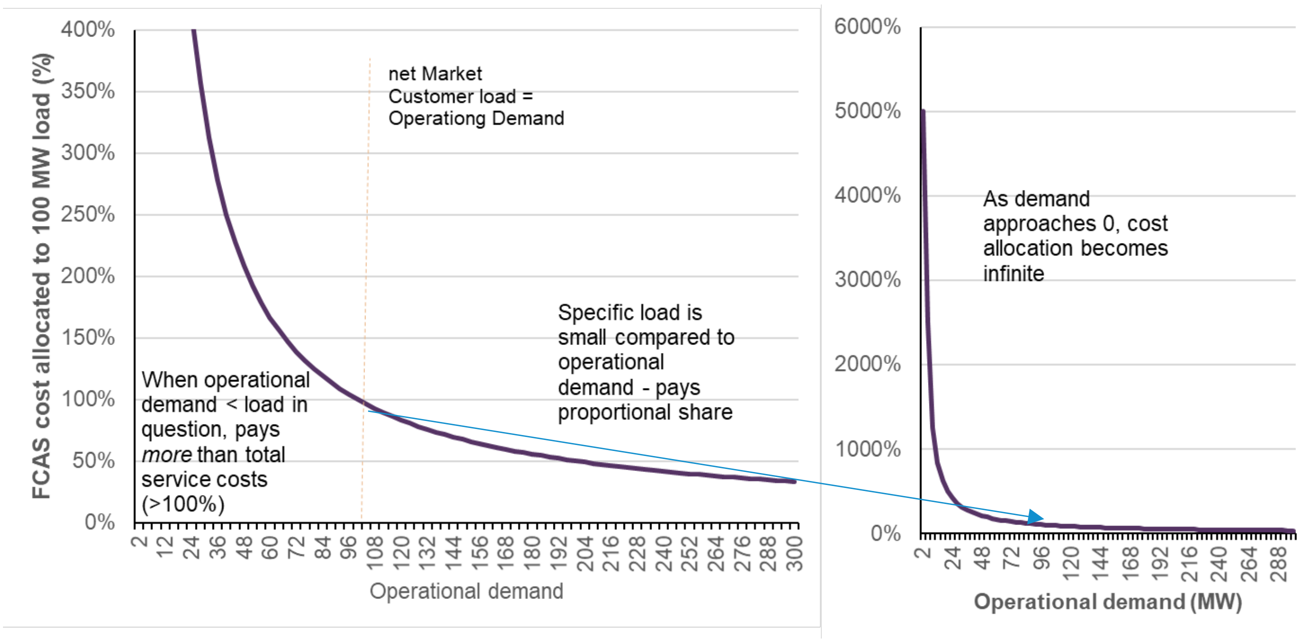
Finally, case (4) demonstrates that as the operational demand approaches 0 MW, the denominator will become small compared to the remaining Market Customers, and customers could be exposed to unbounded costs (limited only by any minimum resolution

[5] Each relevant clause of the NER uses a specific expression the relevant denominator, but operational demand is used here as a reasonable and intuitive proxy

of AEMO's systems). In the case (4) example, a 100 MW load could pay 100x the total service cost.

This is also shown in Figure 3. As the operational demand decreases, the remaining loads pay a higher share of the costs of the service, despite not contributing to a greater need for the service. As the operational demand approaches (and then goes below) that of a specific load, that load may be required to pay *more* than 100% of the total service costs – with the extra being paid to the net exporting load (or to AEMO, depending on the interpretation of the NER), despite that exporting load not contributing to the service (and also not paying for any contribution)[6].

Figure 4 Schematic sensitivity of allocated costs vs operational demand



1.5.1 South Australian example

This is not merely a theoretical argument; the cost impacts to customers of South Australia *approaching* 0 MW, or any other sufficiently low level of operational demand are likely to be material.

Regional contingency lower FCAS services can be above $100,000 for a single trading interval (TI) in SA. Indeed, since 2017 there have been over 20 TIs where total lower contingency costs were over $500,000 in the state. If such a price event were to occur at a time of very low operational demand, resulting in individual customers paying multiple times the total regional costs as outlined above, Infigen believes the impact would be unacceptable to all stakeholders.

As a specific example:

[6] Note that if Operational Demand goes negative, the sign will flip leading to large payments rather than costs, and vice versa. The asymptote will be limited by the precision of the demand in AEMO's systems.

- between 6:00 and 7:00 am on 9th November 2019, an average of more than 100 MW of each fast (6 second) and slow (60 seconds) lower contingency service was enabled in South Australia. In the 6:30 am TI each of these services settled at over $13,000/MWh, while in the 7:00 am TI they settled at the market price cap (MPC) of $14,700/MWh.
- The total cost of lower contingency services to the region over this hour-long period was $3.4m, with all loads paying a proportional share.
- If this scenario had coincided with a period of low regional demand then as regional demand approached 1 MW, the cost to a 20 MW industrial load would be up to $68m or – 20x the actual cost of the service.
- This would be equivalent to an average cost of $485/MWh over the year (assuming 80% load factor). That is, a single hour of low-demand coinciding with high local non-energy costs could be significantly higher than the load's entire annual cost.
- This is equivalent to applying a $3,400,000/MWh cost to the load during the event, compared to an MPC (at the time) of just $14,700/MWh.
- This would be a ~$68m transfer from that single 20 MW load to net exporters, clearly an outcome not intended by the current NER

This scenario demonstrates that as the operational demand decreases under current settlement systems, the MPC may no longer adequately protect consumers or reflect consumer preferences. Market customers will be exposed to unnecessary (and unrealistic) cost that they may not be able to absorb.

It could also lead to "death spiral" like outcomes, where customers are incentivised to disconnect during low-load periods.

This does not seem consistent with good market design and has other perverse outcomes such as creating an incentive to push demand negative, which may not be good for the market.

1.6 Cost recovery from Market Generators

We note that a parallel issue could occur for Market Generators if, at the extreme, no Market Generators are operational in South Australia (e.g., if the output of embedded generation alone resulted in South Australia exporting at the interconnector limits, or if residual SA demand was met by imports from Victoria). This would leave AEMO without any SA participants among which to share the cost of local contingency raise services. In addition, given most generators have auxiliary loads that continue even when those generators are offline, this would result in some Market Generators having negative "generation".

This scenario appears relatively unlikely in the coming year, including because in such cases AEMO is currently likely to direct several South Australian generators to remain online.

We do not consider this an urgent issue, however we do note that under the current rules the outcome that "solves" this issue for generators exacerbates the problem for loads as it necessitates directions during times of increased price sensitivity and could conceivably result in market customers paying (via a compensatory direction charge) for the cost of regional contingency raise services as well.

2. Potential impacts and need for urgency

2.1 Disruptions to the NEM

Disruption to South Australian industry

Customers in South Australia risk being exposed to material costs (in excess of $1,000,000/MWh) if local non-energy costs must be recovered during a low demand period. This would involve significant but spurious (non-physical) costs imposed on a subset of customers – discriminating particularly against large industrial customers.

Risk of cascading defaults and disruption of the administration of the NEM

If extreme costs are non-recoverable, in addition to the impact on the affected consumers and businesses, this could lead to retailers defaulting on their settlements to AEMO. In turn, this would force remaining customers of that retailer to be shifted to the retailer of last resort – resulting in significant disruption to the market, implications for contracting (including the RRO), and generally distracting AEMO from the critical period in the lead up to summer.

This would have serious consequences for retail competition in South Australia.

System security and reliability risks

Sudden, extreme non-energy costs being recovered from customers – even if only $50,000/MWh – will incentivise behaviours that risk the security and reliability of the NEM.

The applied costs are likely to be in excess of the Value of Customer Reliability. Market Customers with a positive load (i.e., not net exporters) will have a very strong incentive to reduce consumption, i.e., load shedding. As most loads are effectively non-scheduled, this will not be communicated to AEMO ahead of time, and load may drop off suddenly and dramatically. This is analogous to the Urgent rule change put forward to the AEMC by the AER in response to similar proposed behaviour by semi-scheduled generators.

If this happens, the operational demand will further decrease, further sharpening the incentives for loads to disconnect, leading to a "death spiral" of load shedding.

Given that one of the triggers for this scenario is high lower contingency FCAS costs, AEMO may simply not have the resources available to manage a sudden drop off in demand. This could force directions, the disconnection of exporting loads (i.e., consumers with rooftop PV), or at the extreme an inability to operate the NEM in a secure state.

Finally, this could also impact on batteries which would normally have an incentive to charge during low demand periods. In this case, batteries would not want to act as loads. Embedded batteries would be incentivised to discharge, which means these resources would not be available for the future. Assuming local reserve procurement or intervention costs were triggered by an already stressed system, this could deprive AEMO of valuable resources in future periods (or AEMO would be required to direct resources, if possible, and pay significant compensation).

Disruption of settlements

If the operational demand (or, specifically, the relevant denominator in that section of the NER) reaches zero, AEMO's systems will fail. With no alternative recovery mechanism considered in the NER, AEMO will not be able to recover non-energy costs and therefore be unable to carry out their responsibilities under the NER. This will critically impact AEMO's ability to administer the NEM, and will lead to uncertainty for participants.

2.2 Likelihood

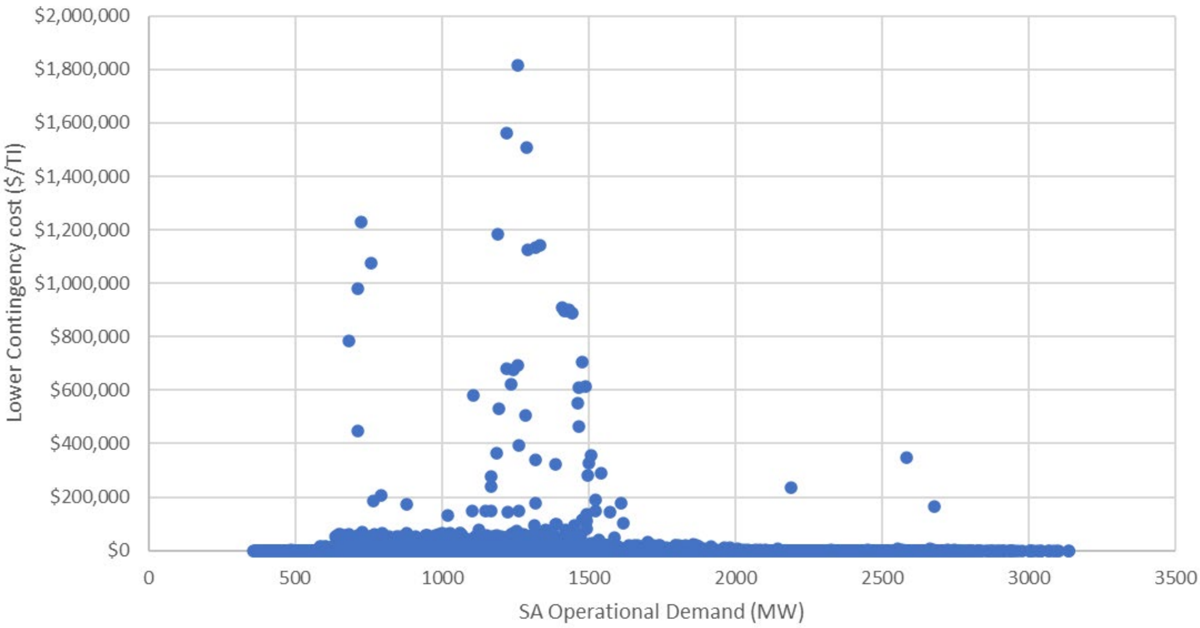
As discussed above, the status quo risks significant distortion to settlements in South Australia. The *risk* is driven by: (i) the risk of low operational demand; (ii) the risk of this coinciding with material, local non-energy costs; and (iii) the consequences.

Risk of low operational demand

AEMO has identified that the risk of zero or negative operational demand is already material. As such, the risk of *low* operational demand at a level that could cause distortions this year will be *very likely*.

On local non-energy costs: FCAS services can be above $100,000 for a single trading interval (TI) in South Australia. Since 2017 there have been over 20 TIs where lower contingency costs were over $500,000 in the state. Local requirements are particularly driven by islanding events or by the threat of islanding events. For example, Figure 5 shows the Lower Contingency Cost in South Australia. Note that several extreme events (above $100,000/TI) occurred when operational demand was ~700 MW. It is therefore *highly credible* that extreme events *if they occur* will occur when demand is low. Furthermore, when South Australian demand is low in the future, there may be a shortage of suitable lower FCAS providers – leading to higher lower FCAS prices. Similarly, operating an islanded system (or under threat of islanding) may increase the likelihood of interventions.

Figure 5 Lower Contingency FCAS costs in South Australia vs operational demand



The top 20 highest Lower Contingency FCAS periods are shown in Table 2. Note that these occur at a range of times (4:30am to 8pm), a range of rooftop PV outputs (0 to 900 MW), and a range of operational loads. We find no evidence to suggest that extreme Lower contingency FCAS costs could not occur during low demand periods. In fact, we find that if similar underlying conditions were repeated today (with the subsequent structural changes), the risks highlighted above would be triggered.

Table 1 Top 20 highest SA Lower Contingency FCAS periods (2018-present)

TI Ending	SA Lower Contingency Cost ($)	SA Operational Load (MWav)	Rooftop PV (MW)
9/11/19 7:00	1,816,766	1,256.55	48
9/11/19 6:30	1,561,487	1,221.16	18
14/2/20 12:00	1,509,097	1,289.99	476
2/3/20 13:30	1,228,287	725.49	904
9/11/19 6:00	1,183,944	1,188.45	2
16/11/19 20:00	1,142,064	1,333.02	0
16/11/19 19:30	1,132,921	1,319.87	10
16/11/19 19:00	1,125,597	1,293.91	53
2/3/20 13:00	1,073,564	758.39	897
2/3/20 14:00	978,244	712.95	889
1/2/20 5:00	907,249	1,409.20	0
1/2/20 6:00	898,946	1,432.15	0
1/2/20 4:30	896,459	1,430.27	0
1/2/20 5:30	895,690	1,416.09	0

1/2/20 6:30	887,546	1,443.30	0
2/3/20 14:30	783,224	683.21	856
1/2/20 4:00	705,917	1,479.27	0
14/2/20 13:30	694,326	1,256.54	545
13/2/20 4:30	678,909	1,219.53	0
14/2/20 12:30	678,326	1,244.65	525

Notable are middle of the day periods that correspond with very high solar outputs. For example:

- A separation event occurred at approximately 12:20 on 2020-03-02 (a Monday). During the 13:30 TI identified above, there was 904 MW of rooftop solar and an operational demand of 725 MW. In fact, this period was the peak rooftop PV output for Q1 2020.
- In comparison, the minimum South Australian load period in 2020 was 12:30 on 11th October 2020 (Sunday), with peak rooftop solar of 992 MW and "native" demand (operational demand+rooftop solar) of ~1300 MW. If the March event had occurred on a Sunday in October instead of a Monday in March, its operational demand could have been ~300 MW lower (~400 MW).
- The peak rooftop PV output in South Australia has already increased by 230 MW since March 2020. By September this year, AEMO is projecting zero or negative operational demand, down from 300 MW in October 2020. This implies AEMO expects a further reduction in net demand of *at least* 300 MW. The March separation event could therefore feasibly occur during a period with an operational demand of ~0-100 MW, if it happened to take place in October this year.

This is not to say that these coinciding events *will* occur. But from a risk management perspective, allowing a Very High risk of low demand and a Possible risk of material non-energy costs which would lead to a Catastrophic event for SA consumers and the market and does it does not seem consistent with the NEO. As discussed below, it would risk imposing significant costs on a subset of SA consumers, or risk creating significant distortions to dispatch behaviour.

3. Possible solutions

An enduring solution will require a more comprehensive consideration of how non-energy costs are recovered. AEMO has proactively identified this issue in the Integrating Energy Storage Systems rule change, which proposed new bi-directional registration categories, and AEMC has presented a series of helpful discussion papers.

AEMO has identified in its consultation paper a range of alternative approaches, including:

- When consumption for a trading interval is less than 1 MWh, recovering non-energy costs based on average consumption over the past calendar year or rolling 365 day average
- When consumption for a trading interval is less than 1 MWh, recovering non-energy costs based on the last period with regional consumption larger than 1 MWh
- When consumption for a trading interval is less than 1 MWh, recovering non-energy costs equally from each active Market Customer

These options would *mathematically* allow AEMO's systems to operate even under zero or negative operational demand. However, these proposed options do not address the more pressing issue of *low* operational demand and, in particular, the distortions arising when some Market Customers have negative net load (specifically, AGE).

3.1 Infigen proposal

Infigen proposes an alternative option that would defer the zero operational demand problem (allowing time for a more considered discussion of cost allocations), while also addressing the settlement issues that seem to occur around low operational demand.

The key near-term problem is negative AGEs from some (but not all) Market Customers pushing regional (operational) demand to low or negative levels. Removing these negative AGEs from (and only from) the relevant settlement equations would defer the issues presented above. Infigen therefore proposes that the AGE of a Market Customer could modified to be:

$$\text{Allocated cost} = \text{Service cost} \times \frac{\max(0, \text{Market Customer's AGE})}{\sum \max(0, \text{AGE})}$$

This would help allocate costs fairly between participants, with total costs recovered being limited to the total service cost.[7]

This approach assumes that there will continue to be net loads in the system offset by significant solar exports (negative loads) in other areas. It would not provide a solution if *all* Market Customers in a region had negative load for a DI. However, Infigen understands this is very unlikely in (at least) the next 12-24 months; we suggest the AEMC could work with AEMO to examine current trends of individual Market Customers. Instead, this solution would allow time for more fundamental reforms to be undertaken by the AEMC including under the Integrating Energy Storage Systems rule change proposed by AEMO.

3.1.1 Worked example

Reconsidering case (3) from Figure 2, while the operational demand would remain unchanged at 100+100+(-100)=100 MW, the denominator of the settlement equation would

[7] Infigen has also considered allocating costs based on the absolute value of a Market Customer's load. This would help ensure loads that are currently exporting continue to pay *some* share of the services they require. However, discussions around long-term cost recovery from bidirectional resources may mean a more complex structure is not required at this time.

become 100+100+max(0,-100) = 200 MW. Loads A and B would therefore each pay 100/200x$3m = $1.5m, and Load C would pay zero, consistent with case (2). The same would apply for case (4).

3.2 Alternative solutions

Infigen has considered other possible solutions including:

- AEMO has proposed an alternative settlement mechanism based on a share of average historical demand when operational demand is less than 1 MWh in a trading interval. This would not address the settlement or reliability and security risks considered here. However, the AEMC could increase the threshold in AEMO's solution from 1 MWh to (say) 150 MWh per trading interval (300 MW average demand). We consider this a workable solution, but would result in a more frequent disruption to settlement. We suggest this would only be preferable if the implementation costs or timeline of Infigen's preferred solution were insurmountable or there are other issues we have not identified.
    - The relevant threshold could also be informed by AEMO modelling of the largest expected net Market Customer load in South Australia at times of low demand. The threshold could be set to ensure trigger if net-demand approaches some multiple of the net customer load.
- AEMO could apply a settlement cap such that payments from any single Market customer could be no more than the total cost to be recovered, and no spurious payments could be made to Market Customers due to negative loads. This would limit the worst outcomes, but would likely to be complex to administer.
- Redistributing excess recovered costs. An alternative fix would be to change the Rules to allow AEMO to return excess cost recoveries to affected Market Customers. This seems challenging to manage and operate, and would not address the issue of equations breaking at zero or negative demand, still requiring an alternative fix.
- Immediately moving from cost recovery on single TIs to across multiple periods (e.g., one week/month/year) at all times. This would be a very material change and would require more consideration than time allows.

4. Impacts, costs, and benefits

4.1 Affected parties

4.1.1 Market Customers with positive loads

The current rules place some market customers at risk of material, and potentially unrecoverable, costs. This creates a major risk to those customers which will be difficult to manage. In particular large industrial loads, that are unlikely to fully offset consumption with embedded generation, could be exposed to costs in a single hour that exceed their entire annual wholesale energy costs. This risks the viability of those businesses as well as of their retailers, if applicable, if those costs cannot be recovered.

Infigen's proposed change would ensure that customers only pay their "fair share" of system costs, and that total recovered costs do not exceed the total cost of the service.

4.1.2 Market Customers with zero or negative loads

Under both Infigen's proposal and the status quo, Market Customers with zero consumption are not exposed to non-energy costs.

Currently, Market Customers with negative consumption *may* receive a negative settlement, i.e., a payment. This does not reflect any provided response or enablement in a defined service. As such, we do not expect that Market Customers would "expect" this payment or that removing it would materially distort the market. Any offered services would still be renumerated as pre normal – Infigen's proposed changes would only affect cost recovery.

4.1.3 AEMO

Operating with low Operational Demand creates new challenges for AEMO, including potentially lower availability of reserves, less synchronous resources, inertia, and system strength, and fewer options for managing system security. Under the status quo, when Operational Demand is low and particularly if there are local non-energy costs, the remaining (positive) Market Customers have an incentive to decrease their consumption – exacerbating what may be a challenging period for South Australia. This could include customers draining their batteries to reduce their exposure (or, potentially, increase their payments), which creates a future reliability or system security risk.

Infigen's proposal will remove these disincentives and deliver AEMO a more predictable system.

AEMO will need to implement changes to their settlement systems. AEMO has previously estimated that implementing changes to their settlements system would cost less than $100,000. We expect that our proposed changes, which require a relatively minor change to the calculation of AGE, should be no more complex to implement than AEMO's proposals for implementing alternative average or rolling average demands. However, as the proposed arrangements would be expected to operate at all times, there may be greater IT and audit costs.

4.2 Contribution to the NEO

- **The current Rules create the risk of material, unhedgeable costs for some energy consumers (with the immediate risk being in South Australia but with the risk increasing to other regions over time).** A local cost coinciding with low operational demand would result in material but unnecessary costs being allocated to a subset of South Australian loads. This could have a material impact on the viability of some customers, especially large users that do not have sufficient rooftop PV to offset their load. The magnitude of the costs could exceed those businesses' ability to pay.

Infigen's proposed rule will ensure that negative Market Customers do not distort settlement for the remaining Customers. This is in the long-term interest of consumers.

- **Infigen's proposed Rule will defer the need for more complex settlement systems, and allow the AEMC's current rule changes to progress.** This will help ensure a more efficient allocation of costs to both consumers and generators.
- **Without changes, AEMO's settlement systems may fail this year.** This would lead to market settlement disruption, with no alternative under the NER to allocate costs, and would not be in the interest of consumers.
- **Infigen's proposed changes will reduce incentives to exacerbate low operational demands.** Infigen's proposed change would reduce incentives for loads to disconnect during times of low operational demand, which could exacerbate AEMO's emerging operational challenges, and potentially require greater interventions (such as shedding customers with rooftop solar). This will improve the reliability of supply to customers.
- **The proposed change will remove distortions that threaten system reliability and security.** Currently, loads would have an incentive to *export* embedded batteries if local non-energy costs are likely to be incurred during times of low operational demand (to either earn a share of negative settlement costs or avoid or mitigate their disproportionate share of costs). This creates a risk of future shortages in reliability or system security resources. Infigen's proposed change will improve the security and reliability of supply to customers.
    - Note that the benefit of reducing consumption during a low demand period can significantly exceed the Market Price Cap

5. Proposed drafting

In their consultation, AEMO has identified a number of services that will require updates to the relevant clauses.

Table 2 Clauses requiring amendment (Source: AEMO[8])

Payment type	Cost recovery based on aggregate regional demand	NER clause
Market ancillary services		
FCAS – contingency lower	Trading interval	3.15.6A(g)
FCAS – regulation	Trading interval	3.15.6A(i)(2)
Non-market ancillary services		
Network support control ancillary services (NSCAS)	Trading interval	3.15.6A(c8),(c9)
System restart ancillary services (SRAS)	Trading interval	3.15.6A(e)
Interventions		
Compensation for direction – energy, FCAS or other services	Trading interval(s) when direction in effect	3.15.8(b),(f),(g)
Reliability and Emergency Reserve Trader (RERT) payments	Split between:	3.15.9(e)
Affected participant compensation for RERT	• RERT usage charges and compensation payments – trading intervals when RERT was used. • RERT availability/other charges – billing week when paid.	
Compensation - market suspension – energy and FCAS	Trading interval(s) within a market suspension pricing period	3.15.8A(b),(f)
Other events		
Administered price cap or floor price compensation	Trading intervals in the eligibility period for compensation claims under clause 3.14.6	3.15.10(b)

We present below specific examples of clauses with our proposed drafting, which can be readily generalized to the other services.

5.1 Lower Contingency service

Clause 3.15.6A(g) prescribes how cost recovery for the fast lower service, slow lower service and delayed lower service should be recovered from Market Customers. The trading amount (TA) to be recovered from a Market Customer is given by:

8 https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/nem-settlement-under-zero/nem-settlement-under-zero-and-negative-regional-demand-conditions.pdf?la=en

$$TA = RTCLSP \times \frac{TCE}{RATCE} \times -1$$

where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
RTCLSP (in $)	=	the total of all amounts calculated by *AEMO* as appropriate to recover from the given *region* as calculated in this clause 3.15.6A(g) for the *fast lower service*, *slow lower service* or *delayed lower service* in respect of *dispatch intervals* which fall in the *trading interval*;
TCE (in MWh)	=	the *customer energy* for the *Market Customer* in that *region* for the *trading interval*; and
RATCE (in MWh)	=	the aggregate of the *customer energy* figures for all *Market Customers* in that *region* for the *trading interval*.

The total lower service costs to be recovered from the region (for a given trading interval) is RTCLSP, which is the sum of:

- the global market ancillary service requirement cost for that region, for all dispatch intervals in the relevant trading interval, as determined pursuant to clause 3.15.6A(g)(3); and
- all local market ancillary service requirement costs for that region, for all dispatch intervals in the relevant trading interval, as determined pursuant to clause 3.15.6A(g)(3)

Clause 3.15.6A(g)(3) is:

> allocate for each relevant dispatch interval the sum of the costs of the global market ancillary service requirement and each local market ancillary service requirement calculated in clause 3.15.6A(g)(2) to each region as relevant to that requirement pro-rata to the aggregate of the customer energy figures for all Market Customers in each region during the trading interval

We interpret this clause as meaning that when the aggregate of the customer energy figures for all Market Customers (i.e., operational demand) is low (or zero), the pro-rata allocation of global lower services to South Australia will be similarly low. However, when local costs are incurred (e.g., when local lower services are procured in South Australia), these will be fully allocated to a specific region's customers.

The critical term is RATCE, which we interpret could expressed as $RATCE = \sum TCE$, such that the proportion of RTCLSP costs to be recovered from Market Customer i is:

$$\text{Share of costs} = \frac{TCE_i}{\sum TCE}$$

This is of the form identified in Section 2.2, and therefore risks distorting the cost recovery when any individual customer energy figure is comparable to the sum of customer energy figures for the region (i.e., operational demand).

5.1.1 Proposed change

TCE (in MWh) = the *customer energy* for the *Market Customer* in that *region* for the *trading interval* or zero if the customer energy for the Market Customer in that region for the trading interval is zero; and

RATCE (in MWh) = the aggregate of the positive *customer energy* figures for all *Market Customers* in that region for the *trading interval*.

The intent of this change would be to deliver a formula:

$$TA = RTCLSP \times \frac{\max(TCE, 0)}{\sum \max(TCE, 0)}$$

5.2 Section 3.15.8(b),(f),(g)

AEMO must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* applying the following formula:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

where

MCP is the amount payable or receivable by a *Market Customer* pursuant to this clause 3.15.8(b);

E is the sum of the *Market Customer's adjusted gross energy* amounts at each *connection point* for which the *Market Customer* is *financially responsible* in a *region*, determined in accordance with clauses 3.15.4 and 3.15.5 in respect of the relevant *intervention price trading intervals* excluding any *loads* in respect of which the *Market Customer* submitted a *dispatch bid* for the relevant *intervention price trading interval* in that *region*; and

RB is the regional benefit determined by *AEMO* pursuant to clause 3.15.8(b1) at the time of issuing the *direction*.

CRA is the *compensation recovery amount*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

AEMO must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* applying the following formula:

$$MCP = \frac{\max(E,0)}{\sum \max(E,0)} \times \frac{RB}{\sum RB} \times CRA$$

5.3 Section 3.15.6A (c8)

In each *trading interval*, in relation to each *Market Customer* for each *region*, an *ancillary services* transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA_{P,R} = \left(\sum \left(TNSCAS_{S,P} \times RBF_{S,P,R}\right)\right) \times \frac{\max\left(AGE_{P,R},0\right)}{\sum \max(AGE_{P,R}.0)} \times -1$$

...

~~AAGEp,r (in MWh) = the aggregate AGEp,r figures for all *Market Customers* in respect of the relevant *region* and *trading interval*~~

5.4 Section 3.15.6A (c9)

$$TA_P = TNSCAS_P \times \frac{\max(AGE_P,0)}{\sum \max(AGE_P,0)} \times -1$$

[..]

~~AAGEp (in MWh) = the aggregate AGEp figures for all *Market Customers* in respect of the relevant *trading interval*.~~

Conclusion:

We look forward to engaging with the AEMC and market participants on these urgent changes.

Yours sincerely

Ross Rolfe