30 June 2026

Electricity Authority
PO Box 10041
Wellington 6143

Via email: OperationsConsult@ea.govt.nz

To whom it may concern,

Re: Consultation Paper— Common quality and wholesale market arrangements for BESSs and BESS-hybrid stations

NewPower Energy Services Ltd (NewPower) appreciates the opportunity to make this submission on the Electricity Authority's consultation on common quality and wholesale market arrangements for battery energy storage systems (BESS) and BESS-hybrid stations.

NewPower, the holding company for Infratec NZ Limited (Infratec) and NewPower Energy Limited (NEL), are subsidiaries of WEL Networks Limited, New Zealand's sixth largest Distributor. Infratec, an Engineering, Procurement and Construction (EPC) company, is delivering low-carbon utility-scale solar and battery solutions at a time of unprecedented growth in New Zealand. Infratec developed and commissioned Rotohiko, NZ's first utility scale 35 MWh battery energy storage system (BESS) facility at Huntly, connected to WEL Networks' distribution network.

By way of context for this submission, NEL is the owner, operator and trader of generation assets including the Rotohiko BESS, which operates within both Network and Grid compliance modes, and so can offer a range of network, transmission, and energy market services within NZEM's wholesale market dispatch compliance rules. This BESS is already contracted to the System Operator as an ancillary service agent for instantaneous reserves.

Infratec has also constructed and commissioned approximately 202 MW of utility-scale solar farms connected to distribution networks across New Zealand for both NEL and customers, with an additional 30 MW currently under construction.

Key points in our submission

In summary:

1. NewPower welcomes the Authority looking at market changes regarding BESS and BESS-hybrid stations.

AOPOs for 'idle' BESSs and BESS

2. NewPower has highlighted the cost of frequency management for BESS, particularly lost arbitrage revenue.
   a. The Authority stated in its frequency decision paper that it believed the NewPower estimated frequency management cost increases were exaggerated. NewPower stands by its view that frequency management costs for BESS will increase significantly due to the frequency AOPO changes coming into effect July 2026.

  b. NewPower would like to take this opportunity to highlight to the Electricity Authority that these decisions around BESS frequency related AOPO can materially impact the business case of a BESS.
  c. NewPower has taken the Authority through its BESS frequency management cost modelling in detail. The results of this modelling can be found in Appendix 1.

3. NewPower notes that internationally BESS participates in frequency response markets and are compensated for their frequency support.
  a. NewPower notes that in this consultation the Authority states "*In many European countries, notably Germany, France and the United Kingdom, BESSs have already become key providers of **frequency response** and reserves, helped by reforms that have **enabled BESSs** to **access the markets for these services**.*"
  b. NewPower notes that in New Zealand a large portion of frequency response has historically been provided for "free" due to AOPOs. NewPower questions if this approach is fit for purpose for the future, especially with plant like BESS where the frequency management costs can be high. This should be considered in the overall frequency management strategy being worked on by the Authority and the System Operator.

4. NewPower would like to highlight that BESS' often act like peaker generators. The AOPOs currently don't require the typical peaker generators to comply with AOPOs when they are 'idle'.

5. NewPower suggests that there is a robust definition of 'idle' be defined. This definition should include real power thresholds and exclude reactive power.

AOPOs for BESS-hybrid stations and transmission generating stations

6. What if a hybrid BESS is less than 10 MW and the intermittent generation component is larger than 10 MW? NewPower argues the frequency and voltage AOPOs should not apply to a BESS component in this case. Otherwise, it is disadvantaged from stand-alone BESS less than 10 MW.

7. The Authority needs to ensure AOPO compliance is clear when there are outages on hybrid generation station components (i.e. outage on BESS component or outage on intermittent component).

Wholesale trading arrangements for BESS-hybrid stations

8. NewPower's view is that for Hybrid-BESS plants the intermittent portion of the generating station should still offer using the status-quo UN-010 offer form with FOGP. The BESS portion of the generating station should be offered with the status quo offering forms as well.
  a. The market should be able to net the offering positions of the intermittent portion and BESS portion.

9. NewPower's view on how hybrid DC connected BESS inverter constraints should be treated is that it should be relatively fast to update and should not impact the price that the hybrid plant receives.

NewPower welcomes discussion with the Authority on any points raised in our submission and is happy to provide further clarification or information.

Yours Sincerely,

David Barnett
Acting Chief Executive Officer
NewPower Energy Services Ltd

Appendix 1: BESS Frequency Management Cost Modelling

Introduction

In this section NewPower outlines its modelling for estimating the cost of BESS providing frequency management. Note that this section only focuses on the main cost which is lost energy arbitrage revenue. There are also additional costs such as:

- Throughput degradation of BESS for frequency keeping energy
  - BESS is using up its State of Health (SoH) for frequency keeping

- Efficiency losses in the BESS system due to frequency keeping throughput
  - Electrical losses
  - Increased cooling system losses

- Compliance costs
  - Testing costs
  - Simulation modelling costs

Frequency Variability

NewPower's original assumption for its modelling is that frequency variability in the future will be approximately the same as that recorded in mid-2024. The rationale behind this assumption is that the frequency related code changes will approximately cancel out the impact of more intermittent generation and load coming online in the future.

Modelling by the System Operator in "Part 8 Review: Frequency Studies (2a and 2b)" study (included in the Electricity Authority's June 2024 frequency management consultation) shows the frequency variability in 2035 with the new 0.1 Hz deadband will be greater than the 2023 frequency variability. This is shown in Figure 1 below. This indicates that NewPower's original assumption that the frequency variability will approximately the same in future as the in mid-2024 is conservative.

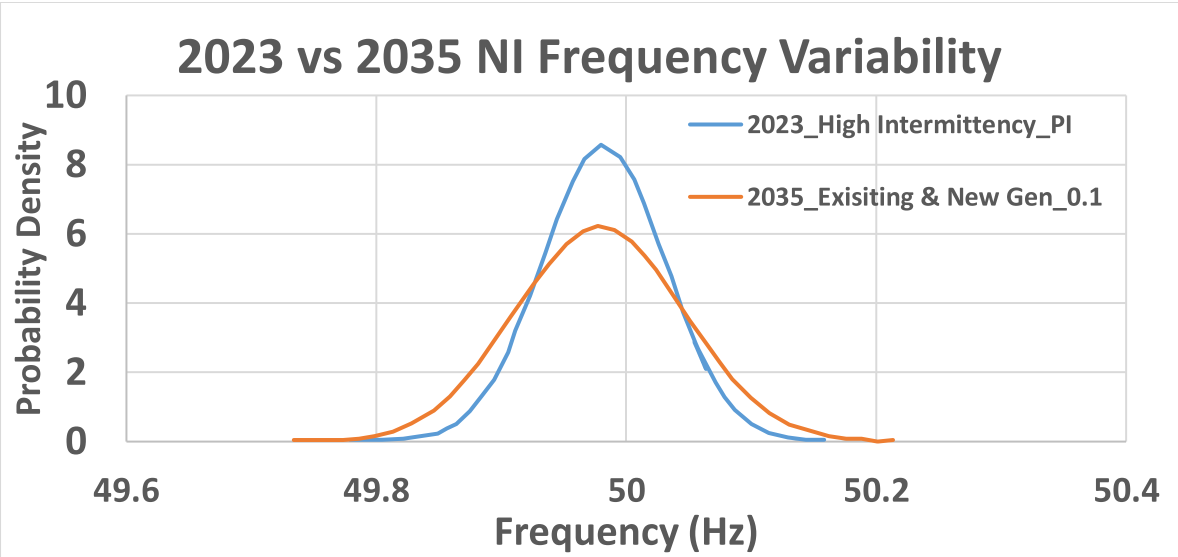

Figure 1: North Island Frequency Variability 2023 vs 2035

To further illustrate the point that BESS will have to work harder Figure 2 has been included below. This shows that a hydro generator (in the South Island) will be working harder to provide frequency response with a deadband of 0.1 Hz. The frequency response from a BESS is similar to a hydro generator.

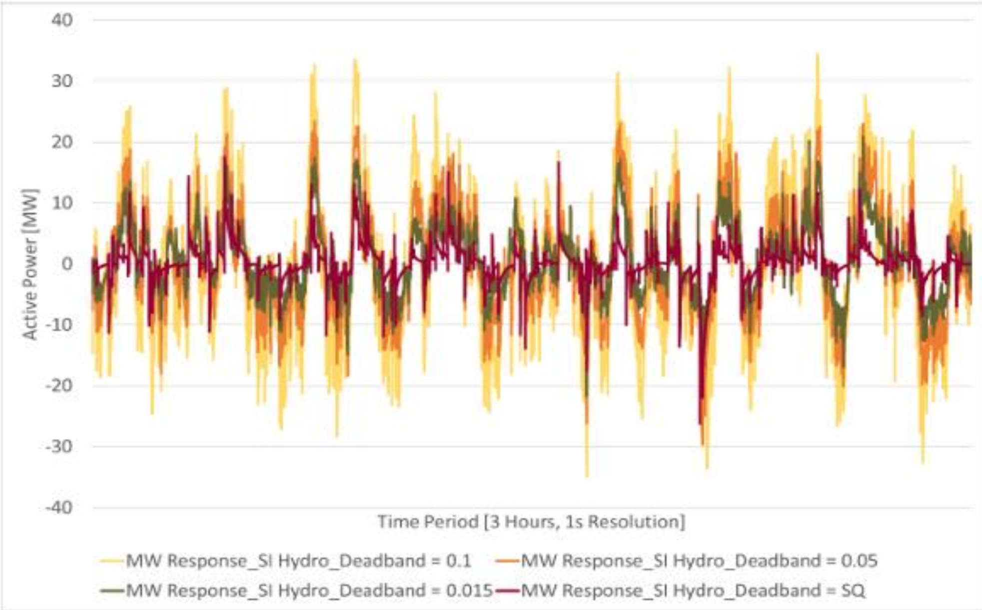

Figure 0-19: Study case 2, MW Response over time

Figure 2: SO Modelled Hydro Frequency Response

Lost Arbitrage Cost Modelling

NewPower has conducted this modelling based on a 250-second-long frequency recording at Rotohiko at one second intervals. Rotohiko's frequency droop response has been modelled using the recorded frequency as the input. The modelling is based on a battery the size of Rotohiko BESS.

Table 1: Modelling Results - Showing Modelled Freq. Response Energy Volume and Associated Lost Arbitrage Cost (BESS frequency response only charging and discharging)

	2024 Freq. Variability – Annual Volume	2024 Freq. Variability – Annual Cost	2035 Freq. Variability – Annual Volume	2035 Freq. Variability – Annual Cost
Deadband 0.2 Hz	12.0 MWh	$1,198.3	320.7 MWh	$32,072.7
Deadband 0.1 Hz	648.4 MWh	$64,841.8	2158.3 MWh	$215,831.6

The results in Table 1 are for BESS frequency management only when discharging / charging (NewPower estimated this to be 41.2% of the time). As can be seen in Table 1 the modelled frequency keeping volumes and associated lost arbitrage revenue costs increase significantly with the new 0.1 Hz deadband and increase in frequency variability in 2035 (as modelled by the System Operator). With an increase in frequency keeping costs of +5,400% for frequency variability staying the same as in 2024, or an increase of +180,000% if frequency variability does increase to 2035 levels modelled by the System Operator.

Table 2: Modelling Results - Showing Modelled Freq. Response Energy Volume and Associated Lost Arbitrage Cost (BESS frequency response all the time)

	2024 Freq. Variability – Annual Volume	2024 Freq. Variability – Annual Cost	2035 Freq. Variability – Annual Volume	2035 Freq. Variability – Annual Cost
Deadband 0.2 Hz	28.7 MWh	$2,866.8	767.3 MWh	$76,728.8
Deadband 0.1 Hz	1551.2 MWh	$155,123.9	5163.4 MWh	$516,343.5

As can be seen in Table 2 the modelled frequency keeping volumes and associated lost arbitrage revenue costs increase significantly with the new 0.1 Hz deadband, frequency management when idle, and increase in frequency variability in 2035 (as modelled by the System Operator). The percentage increases in energy volumes / costs for frequency management are the same as in Table 1, but the values are larger due to BESS frequency keeping also when idle.

Below are figures showing the modelled BESS frequency management response for the different scenarios.

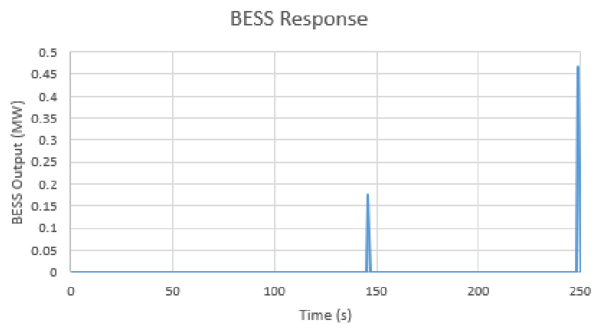

Figure 3: BESS Response - 0.2 Hz Deadband - Freq. Variability 2024

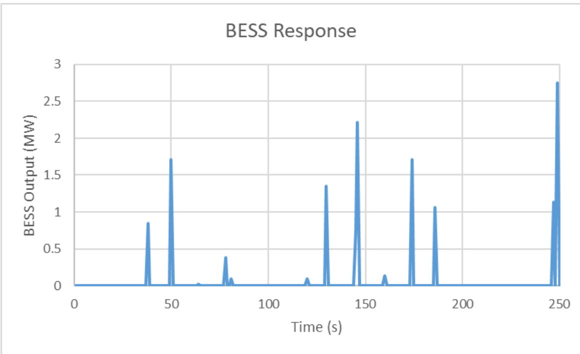

Figure 4: BESS Response - 0.2 Hz Deadband - Freq. Variability 2035

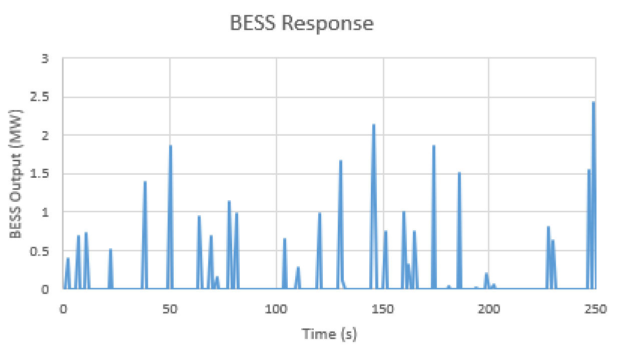

Figure 5: BESS Response - 0.1 Hz Deadband - Freq. Variability 2024

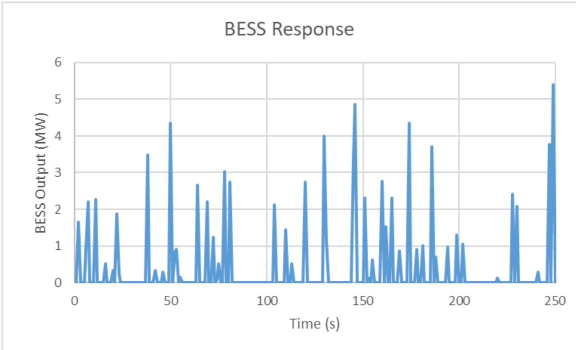

Figure 6: BESS Response - 0.1 Hz Deadband - Freq. Variability 2035

Summary

NewPower's modelling for frequency management costs for BESS indicates significant increased costs for BESS with the new 0.1 Hz deadband (being introduced 1 July 2026) and BESS providing frequency management when idle.

NewPower notes that actual future costs will depend on the actual frequency variability in the future. We have used variability from a 2024 frequency sample and estimated 2035 variability based on System Operator frequency variability simulations.

NewPower meet with the Electricity Authority and the System Operator to show and discuss the modelling. Since this meeting Transpower has completed some of its own modelling of frequency management costs for BESS using large amounts of historical frequency data. The results of Transpower's modelling were that the cost on average to BESS was less than NewPower's modelling, but still significant. NewPower welcomes further modelling and costs from the modelling should be used in cost benefit analysis.

Appendix 2: NewPower's response to the consultation questions

Question	Comments
Terminology	
Q3.1. Do you support the proposed 5-level structure for generating asset definitions?	Yes. NewPower believes that the proposed 5-level structure is suitable for the purposes of this consultation.
Q3.2. Do you foresee any implementation issues or unintended consequences associated with the 5-level structure for generating asset definitions?	NewPower has no issues or are aware of unintended consequences at this stage.
Q3.3. Do you have any feedback on the System Operator's recommendations in its *Hybrid Plant Integration* report?	NewPower has read the executive summary of the report, and the following are our comments: • Generally, NewPower agrees with the System Operator recommendations in this report. • The System Operator's definition of idle BESS differs to that proposed in this consultation by the Authority. NewPower is more in favour of the System Operator's definition.
Asset owner performance obligations for 'idle' BESSs and BESS-hybrid stations	
Q4.1. Do you agree with how the Authority has defined the 'idle' operating state of a BESS and a BESS-hybrid station? Please give reasons if you do not agree.	No. Idle should include a threshold and just be based off real power. A real power threshold should exist as many BESS may power their auxiliary loads from the batteries themselves (i.e. perhaps in the range of 5-10 kW). NewPower suggest a threshold based on minimum power required to be offered at generation station level (i.e. 1 MW). Reactive power should be removed from the definition of 'idle'. This is because a BESS connected to distributor network will have voltage control based on the connection agreement with the distributor and is

	likely to be doing some reactive power all the time for voltage compensation.
Q4.2. Do you consider that frequency management obligations should apply to an idle BESS and an idle BESS-hybrid station? Please give reasons if you do not agree.	No. NewPower has highlighted to the Electricity Authority in previous consultations, the cost to BESS owners for providing frequency management can be significant. There is significant arbitrage revenue loss due to frequency management using BESS warranted daily / yearly throughput. NewPower has estimated this lost arbitrage revenue to be \$5k to \$16.1k per annum for each MW capacity of BESS (for the 0.1 Hz deadband and frequency management while idling). See Appendix 1 for NewPower's modelling and lost arbitrage revenue cost results. For example, a BESS with a power capacity of 100 MW would lose arbitrage revenue of approximately \$500k to \$1.61m per annum (this is likely in the order of 10-40% of total arbitrage revenue). The frequency management modelling report by the System Operator provided as part of the original frequency management consultation from the Electricity Authority in June 2024 shows that frequency variability increases even with the 0.1 Hz deadband and excluded generation station threshold being reduced to 10 MW. Increasing frequency variability will make generators work harder to manage frequency and BESS has the highest ongoing cost to provide this frequency management compared to other types of generation. NewPower would like to state that at better way of unlocking frequency management from BESS is to create market products for frequency management that are easily accessible to BESS and a BESS can then price its marginal cost to provide frequency management at any given time. Otherwise, BESS generators will have to find ways to recover the frequency management costs or look to avoid these costs.

Q4.3. Do you consider that voltage support obligations should apply to an idle BESS and an idle BESS-hybrid station? Please give reasons if you do not agree.	No, NewPower believes that idle BESS and idle BESS-hybrid stations should not have to provide voltage support obligations. The rationale behind this is that requiring an idle station to provide support services is very similar to requiring a non-synchronised generation station to provide support services. The AOPOs should not encourage Inverter Based Resource (IBR) to disconnect from the grid / network to avoid costly support services when the IBR is idle and not earning revenue.
Q4.4. Do you foresee any implementation issues or unintended consequences that we have not discussed in this paper?	**Higher than Expected Costs** Higher costs than the Authority expected for BESS associated with frequency management. It appears the Authority has not accurately modelled what these costs will be and what the impact will be to BESS / hybrid-BESS stations. NewPower notes that the future of the power system will require BESS and high AOPO costs for BESS will make the business case for BESS more difficult. This may lead to higher energy costs for consumers in the long run. **BESS Warranty limits** A BESS may reach this warranted daily energy throughput and go to 'idle' state for the remainder of day. In this scenario the BESS can't provide frequency management without breaking its warranty. This scenario could have significant commercial impacts for the generator.
Q4.5. What do you consider to be the key benefits and costs associated with applying frequency- and voltage-related AOPOs to BESSs and BESS-hybrid stations in the 'idle' operating state? Please quantify these benefits and costs if possible.	NewPower has provided costs for BESS providing frequency and voltage support for the Authority to use in its net benefit calculations. **Frequency Keeping BESS Costs** From the modelling conducted by NewPower set out in Appendix 1, we have estimated the following:

	• BESS cost of frequency management while in charging and discharging states - $2k to $6.7k per MW of BESS capacity per annum • BESS cost of frequency management in all states (incl. idle) - $5k to $16.1k per MW of BESS capacity per annum. **Voltage Related AOPO Costs** Inverters will consume real power to produce reactive power. One inverter model that NewPower has on its generation sites consume ~20 kW of real power acquired from the spot market for every 1 MVAr of reactive power that is produced. Extending this to an annual basis, if a reasonable average annual energy spot price of **$0.15/kWh** is assumed, the cost of producing **1 MVAr** on an **annual basis** (i.e. 8760 MVArh) is **$26k.**
Applying the AOPOs to BESS-hybrid stations	
Q5.1. Which option for applying frequency AOPOs to BESS-hybrid stations that are in the injection or consumption operating state do you support? Please give reasons for your answer.	NewPower believes that option 2B is preferable out of the two options provided. The reason is that with option 2B, the 'consumption', 'injection', and 'idle' definitions can be associated separately with the BESS component of the hybrid plant. This means that the AOPOs would be applied to BESS the same between standalone and hybrid located BESS. If 'idle' is defined at the point of connection for hybrid plant, then this plant will be in the 'idle' state far less often than a standalone BESS (due to generation from intermittent component). This may lead to the BESS component of the hybrid plant doing more frequency management work than a standalone BESS.
Q5.2. Do you consider there to be options for applying frequency AOPOs to BESS-hybrid stations in the injection or consumption operating state that are	NewPower's thinks another option is to apply the frequency AOPO at the generating station level, but where the BESS component of the hybrid station only has to contribute when the BESS component is not

preferable to those identified by the Authority? Please give reasons for your answer.	idle (noting NewPower has issues with the Authority's definition of idle for a hybrid station). As an example, for a solar-BESS hybrid station: • Only solar component generating – solar only frequency response • Only BESS component not idle – BESS frequency response • Both solar and BESS not idle – combined frequency response • Both solar and BESS idle – no frequency response
Q5.3. Do you foresee any implementation issues or unintended consequences associated with applying the frequency AOPOs to BESS-hybrid stations in the injection or consumption operating state that are not identified in this paper?	Yes. There should be thresholds on each "Level 3" component (intermittent component and BESS component). For example, if a 1 MW BESS was installed on a solar farm with the point of connection capacity of 25 MW, the hybrid station AOPOs should not apply to a BESS of this size. As this would disadvantage this BESS compared to a standalone BESS of the same size. NewPower is looking at installing a somewhat small solar array at our Rotohiko BESS to help power the BESS auxiliaries. In a case like this the Authority needs to ensure that the new hybrid-BESS changes don't make AOPO compliance difficult or confusing. NewPower's suggestion is that the hybrid-BESS changes only apply to hybrid plant with intermittent component and BESS component both over the excluded generation station threshold (soon to be 10 MW).
Q5.4. What do you consider to be the key benefits and costs associated with the options for applying frequency AOPOs to BESS-hybrid stations that are in the injection or consumption operating state? Please quantify these benefits and costs if possible.	**Costs** • As mentioned previously there is a lost arbitrage revenue cost to BESS to provide frequency management in the injection or consumption state of $2k to $6.7k per MW of capacity per annum. • Costs associated with BESS degradation and efficiency losses. • Compliance costs – testing, monitoring, modelling.

Q5.5. Which option for applying the voltage support AOPO to BESS-hybrid stations that are in the injection or consumption operating state do you support? Please give reasons for your answer.	NewPower's preference is for Option 3A, for the benefit reasons mentioned by the Authority in the consultation.
Q5.6. Do you consider there to be options for applying the voltage support AOPO to BESS-hybrid stations in the injection or consumption operating state that are preferable to those identified by the Authority? Please give reasons for your answer.	If BESS is mandated to provide voltage support AOPOs when idle then an alternative option is the same as Q5.2 (i.e. compliance on the station level, but BESS component only has to respond when this component is not idle).
Q5.7. Do you foresee any implementation issues or unintended consequences associated with applying the voltage support AOPO to BESS-hybrid stations in the injection or consumption operating state that are not identified in this paper?	Yes. There should be thresholds on each "Level 3" component (intermittent component and BESS component). For example, if a 1 MW BESS was installed on a solar farm with the point of connection capacity of 25 MW, the hybrid station AOPOs should not apply to a BESS of this size. As this would disadvantage this BESS compared to a standalone BESS of the same size. NewPower's suggestion is that the hybrid-BESS changes only apply to hybrid plant with intermittent component and BESS component both over the excluded generation station threshold (soon to be 10 MW). These AOPOs may require distributed generation to oversize inverters to be sized to the reactive power requirements in the voltage AOPOs, relative to what the actual reactive power requirements are agreed with the distributor. This will lead to some BESS-hybrid stations having a higher LCOE, which is likely to increase long run energy costs for consumers.
Q5.8. What do you consider to be the key benefits and costs associated with the options for applying the voltage support AOPO to BESS-hybrid stations	**Costs** • Inverters will consume real power to produce reactive power. One particular inverter model that NewPower has on its generation sites consume ~20 kW of real power acquired from the spot market for

that are in the injection or consumption operating state? Please quantify these benefits and costs if possible.	every 1 MVAr of reactive power that is produced. Extending this to an annual basis, if a reasonable average annual energy spot price of **$0.15/kWh** is assumed, the cost of producing **1 MVAr** on an **annual basis** (i.e. 8760 MVArh) is **$26k.**
Q5.9. Do you consider that clause 8.23 should be revised to move the point of compliance from the generating unit terminals to the point of connection to the transmission network (on the high voltage side of the connection transformer)? Please give reasons for your answer.	Yes. As what the generation station is capable of doing at the point of connection is reflective on how much voltage support the generation station can provide the local network / grid.
Q5.10. Do you consider there to be an alternative that is preferrable to a reactive power export/import requirement of ±39.5% or ±33% of maximum continuous MW output power, measured at the generating station's point of connection to the transmission network (on the high voltage side of the connection transformer)? Please give reasons for your answer.	Yes, an alternative would be a more case by case basis where the maximum amount of reactive power required from a given generator was calculated. NewPower notes this would add complexity but potentially could have wording in the code to allow a generator not to comply if the network / grid connection cannot take the reactive power.
Q5.11. Do you foresee any implementation issues or unintended consequences associated with moving the point of compliance under clause 8.23 from the generating unit terminals to the point of connection to the transmission network that are not identified in this paper?	Only the potential difficultly of some existing generation to be able to comply. Which is already address in Q5.13.
Q5.12. What do you consider to be the key benefits and costs associated with moving the point of compliance under clause 8.23 from the generating unit terminals to the point of connection to the transmission network? Please quantify these benefits and costs if possible.	**Benefits** • Easy for new IBR generation developers to understand and comply • Less compliance costs in the long run. As reduces the number of compliance points for a generating station to one. • Gives generation stations flexibility to determine what units the reactive power comes from **Costs** • Dispensation costs for existing generators (if legacy clauses don't work for the generator)

	• Testing compliance if required out of cycle or modelling required
Q5.13. Do you consider that legacy arrangements would be needed for existing generation? Please give reasons for your answer.	Yes. There will be existing generators that would require large expenditure to comply with the new regulations. Also existing generators were built prior to these changes were thought of and the impacts were not included in their business case.
Wholesale arrangements for BESS-hybrid stations	
Q6.1. Do you agree with the preferred option of requiring BESS-hybrid stations to offer by technology component except in certain circumstances, over the alternative option of creating new obligations for BESS-hybrid stations? If not, why not?	Yes. NewPower believes that Option 4A of offering the intermittent component and BESS component separately provides the generator with flexibility. The market can just net offers / bids to determine the forecasted station injection or consumption.
Q6.2. Do you agree with our characterisation of the benefits and costs with our preferred option? Are there any other aspects we should consider?	Yes. NewPower has no other considerations to add.
Q6.3. Do you agree station dispatch arrangements should be extended to accommodate BESS-hybrid stations that are offered by technology component? What, if any, other issues do you see with the station dispatch arrangements that are in addition to those identified above?	Yes, station dispatch arrangements should be extended to BESS-hybrid stations. The rationale behind this is if the station dispatch arrangements apply to other generation to provide them flexibility, then they should apply to BESS-hybrid stations. Another benefit which is partially illuded to, is that BESS-Hybrid stations will be able to provide better large firm hedging deals to other market participants. NewPower is fully in support of allowing hybrid-BESS stations to change the capacity of the BESS component in offers / bid in gate closure. NewPower has suggested to the Authority for some time that an option to unlock more BESS energy volume was to allow BESS to revise offers within gate closure. NewPower would expect that if standalone BESS

	should receive the same treatment as hybrid-BESS, as to not provide any unfair advantages.
Q6.4. Considering the options above, how should the System Operator manage network injection from a BESS-hybrid station where injection is limited by inverter capacity? What implications would this have on your processes or systems?	NewPower preference is Option 6B. The reason behind this is that the asset owner will likely need to understand the capacity available for both hybrid components in near real time. Given this the asset owner will be able to provide accurate maximum capacity for each component on the respective offers. Another major reason for preferring Option 6B was due to the Authority stating that Option 6A couldn't rapidly update the capacity when overall capacity changes. NewPower's second preference is Option 6A. The Authority didn't quantify what timeframe 'rapidly update the injection capacity' meant. If this option can update the injection capacity within a minute, then this option could be NewPower's preferred option. NewPower suggests the Authority provides more information on how Option 6A would work. Or the Authority allows a hybrid-BESS station to choose either Option 6A or 6B at the time of construction of the station. NewPower believes Option 6C should be discounted completely if the transmission constraint will de-value BESS generated prices.
Q6.5. Do you agree with our preferred approach to calculating constrained costs for DC-coupled BESS-hybrid stations? Can you provide any insights about what metering arrangements would be required to enable this approach?	NewPower is in favour of Option 7A, but without the requirement for DC side revenue meter grade metering. NewPower believes that either BESS actual dispatch or BESS protection grade metering should be able to be used to split the AC revenue meter volume into intermittent and BESS generation volumes. The reason for NewPower's stance on this is that revenue grade metering on the DC will be expensive as is not a common standard product.