09 Feb 2023

GPO Box 2603
Sydney South NSW 2001

Submitted via AEMC website

Dear Ed and team,

EM00040 – Review of the Regulatory Framework for Metering Services – Draft Report

PLUS ES welcomes the opportunity to provide feedback to the Australian Energy Market Commission's (**AEMC**) Direction Paper - Review of the Regulatory Framework for Metering Services – EM00040.

PLUS ES is a registered Metering Co-ordinator (**MC**) and an accredited Metering Provider (**MP**) and Metering Data Provider (**MDP**) in the National Electricity Market (**NEM**). Our skilled, internal workforce provides metering services across Australia. Our customers range from small residential customers through to Australia's largest manufacturers and mining operators.

PLUS ES's key recommendations are:

- **Accelerating the smart meter deployment** – we support initiatives that will help accelerate the deployment volume of smart meters across Australia. The legacy metering retirement approach by the Distribution Network Service Provider (**DNSP**) will achieve the best stakeholder buy in approach and deliver the most efficient deployment.
- **Reducing barriers to installing smart meters and improving industry co-ordination** - we support the initiative to reduce barriers, which create operational inefficiencies in the installation of a smart meter and have included some additional points for the AEMC's consideration.
- **Improving the customer experience in metering upgrade** – we recognise that the consumer plays an integral role in achieving the targets and reforms of the Post 2025 Market design. It is important that the customer not only agrees to have a smart meter installed but is also educated on the benefits.
- **Opportunities to unlock further benefits for customers and participants** – we

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agree that the data recorded by the smart meter is essential to unlocking further benefits for customers and participants.

Competitive market forces and bilateral negotiations are expected to deliver the most equitable and efficient outcomes.

We support the 'beneficiary pays' approach as MPs, MDPs and other stakeholders should be allowed to earn a reasonable return on any investment in smart metering services. This will encourage innovation and deliver further benefits to customers.

PLUS ES would welcome further discussions in relation to this submission. If you have any questions or wish for further discussion, please contact Helen Vassos on 0419 322 530 or at Helen.vassos@pluses.com.au.

Sincerely,

Jason Clark
Executive General Manager

PLUS ES feedback to the AEMC's Direction Paper questions

Questions	PLUS ES Feedback
A. ACCELERATING SMART METER DEPLOYMENT	
Q1. IMPLEMENTATION OF THE ACCELERATION TARGET	
1. Do stakeholders consider an acceleration target of universal uptake by 2030 to be appropriate?	PLUS ES supports an acceleration target date of 2030, as the timeframe is achievable and realistic.
2. Should there be an interim target(s) to reach the completion target date?	PLUS ES supports interim targets as a mandatory requirement of a well-designed acceleration program. Annual targets are essential mechanisms to ensure responsible stakeholders of the acceleration program, do not defer and/or rear-load their meter roll out programs. We also support that retailers should be the accountable party of the obligation, as they are the parties who nominate the MC. Interim targets should include the following criteria: • Geographical concentration, equitable deployment of smart meters, including a combination of metro and rural areas and equitable distribution of smart meter volume (%) between retailers and DNSPs.
3. What acceleration and/or interim target(s) are appropriate?	PLUS ES offers the following considerations: • **Deployment to be front loaded** – The acceleration program should be front loaded over the first few years, to allow enough time at the 'tail end' of the program to upgrade the more challenging sites. That is, 2029 and 2030 – should allow for <20% of the volume remaining. • **Resource challenges at the tail end of the acceleration program.** Resources increase during any ramp up and generally are abundant during peak volumes. As the volume of work starts to steadily decrease, resources will seek new programs of work. • **Incentives which will benefit Australia's energy efficiency**

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	journey. There is an opportunity for retailers to ramp up prior to the smart meter acceleration program date 2025; especially with the proposed fast tracked rule changes relating to Retailer Led Deployment (**RLD**).
4. **Should the acceleration target be set under the national or jurisdictional frameworks?**	For alignment and harmonisation, the acceleration target should be set under a national framework. This will further optimise operational efficiencies.
Q2. LEGACY METER RETIREMENT PLAN[1] (OPTION 1)	
1. **Do stakeholders consider this approach feasible and appropriate for accelerating the deployment of smart meters?**	PLUS ES supports this option for accelerating the deployment of smart meters. Taking into consideration the feedback PLUS ES has provided in the 'Implementation of the Acceleration Target' section and in this section, this option could deliver a well-balanced and efficient acceleration program. This option also allows the DNSP to develop a legacy meter retirement plan which is flexible enough to incorporate the criteria for efficiency, whilst simultaneously providing the DNSP flexibility to target challenging areas of their network where the smart meter data can deliver benefits.
2. Do stakeholders consider the Commission's initial principles guiding the development of the Plan appropriate? Are there other principles or considerations that should be included?	PLUS ES recommends the following guiding principles: • **Stakeholders in developing the Plan:** DNSPs, retailers and MPs are the key stakeholders to be engaged in developing the Plan, as they will be directly impacted by the smart metering deployment. Jurisdictional governments are and will be indirect stakeholders, as the DNSPs will be guided appropriately by jurisdictional guidelines/initiatives. The jurisdictional governments could support the accelerated smart meter program by streamlining the jurisdictional rules. This includes adopting standard metering installation rules (**MIRs**) to drive additional benefits such as consistency across the NEM

[1] The Plan refers to the forecasting 5 year scheduling plan proposed by the AEMC, approved by a governing body and available to all impacted parties prior to the commencement of the acceleration program.

	whilst supporting AEMC objectives and jurisdictional requirements.
	• **Legacy meter asset age:** The age of the meter asset alone will not deliver an efficient deployment. There is a risk that it could be interpreted as selecting only meters that fall within a specific age group. This would deliver an undesirable outcome as the MP would have to undertake repeat visits to locations to complete the legacy meter conversion to smart meters.
	To optimise deployment efficiencies, the primary determining factor should be geographical concentration. The age of the meter could be a secondary factor used to determine the prioritisation of the network area. For example, where a network area is identified to have a predominantly aged meter population, it could be prioritised in the 5 year Plan. All the legacy meters in that specific area should be scheduled for a smart meter exchange, not only the aged assets.
	• Allowances should be made for a reasonably consistent failure rate over time to mitigate delays and inconvenience for customers in the installation process. This supports PLUS ES' earlier proposal of front loading the acceleration deployment with targets, allowing 2029-2030 to focus on the persistent challenging sites[2].
	• Retiring meters of challenging sites upfront may appeal but this approach will also increase the failure rate in the early years introducing a risk that the retailer will miss deployment targets and potentially result in a larger than expected volume of meters being scheduled towards the backend of the target date. To mitigate such outcomes:
	  ○ Remediation sites should be identified (where known), within a geographical area, for resourcing and planning purposes, but not selected as a planning factor.
	  ○ Network areas known for a large concentration of remediation sites should be evenly distributed through the early acceleration timeframes, 2025-2028.

[2] Challenging sites could include sites with known remediation issues such as asbestos, switchboard/ electrical infrastructure upgrades, no access to the site or meter switchboard etc.

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	○ Jurisdictional financial support should be available for customers who do not have the financial means to remediate their sites to enable a smart meter installation.
3. If this option is adopted, what level of detail should be included in the regulatory framework to guide its implementation? *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	To deliver a well-balanced and efficient acceleration program PLUS ES proposes the following to be included to guide the implementation: • The start date and target date of the smart meter acceleration program • Dates associated with the development and administration of the Plan including: ○ The date the approved Plan is to be made available to market participants. This needs to be a minimum of 6 months prior to the commencement date of the acceleration program. ○ Amendments to the original approved Plan: ▪ Approval of deviations/delays to the Plan based on a set of criteria ▪ The frequency an amendment can be made, e.g. annually etc. ▪ Notification to impacted participants that a Plan will be amended with associated details ▪ Engagement with impacted participants ▪ The date the revised Plan is made available to the retailers and metering providers – allowing a minimum 3 months for retailers and metering parties to make scheduling adjustments • The primary factors which need to be considered in developing the Plan (as per comments provided), such as: ○ Stakeholder approval and endorsement ○ The primary criteria to guide the development of the Plan • The expected release dates/frequency of each retired meter batch – greater efficiencies will be achieved if a retired meter batch is released at once, instead of incremental releases. i.e releasing the retired meters annually instead of monthly. • A timeframe for the retailer to appoint an MC.

	• Timeframes assigned to roles and associated activities – i.e. the retailer has 12 months to complete the meter installation of a batch of meters. Timeframes need to be assigned separately to the retailer and the MC/MP, reflective of their activities. The sum of the timeframe will equate to 12 months. [redacted] • Legacy retirement meters to be identifiable in MSATS. This would drive efficiencies and reduce administrative effort.
4. Do stakeholders consider a 12-month time frame to replace retired meters appropriate? Should it be longer or shorter?	In conjunction with the accelerated program retailers and MPs will also have to manage the current metering requirements such as new connections, metering upgrades, smart metering malfunctions and potentially Retailer Led Deployment. All these current activities have their own deployment timeframes. PLUS ES recommends that 15 months is an appropriate timeframe to replace retired meters. This will enable the retailers to comply with the timeframe obligations of the BAU and accelerated metering activities and provide the required flexibility for the MC/MPs to meet those timeframes.
5. Are there aspects of this approach that need further consideration, and should any changes be made to make it more effective?	Other aspects which need further consideration to make the option more effective: • Engagement of stakeholders by DNSPs to develop the Plan including retailers and MC and MP. – The retailer and the DNSP is known but at this stage the contestable MC/MP will have not been nominated. This should not preclude the MP from receiving the Plan or contributing to its development. The MP experiences in the field will be able to provide valuable input to ensure a well-balanced 5 year distribution of legacy metering exchanges. To assist the MP with forecasting their field resourcing and asset requirements, they need visibility to the Plan, including any subsequent revisions. As a minimum, even if they are not

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	nominated, they need to understand: ○ The geographical distribution per year ○ The distribution per retailer and volumes per geographical area – recognising that customers churn retailers[3]. ○ The type of metering such as the metering information proposed in the AEMC Draft Report. At a minimum, how many phases on a meter or what is controlled by the meter to enable them to determine what meter models are required and the quantity[4]. • The regulatory framework should include the obligations for participants to be notified and the visibility of the legacy metering in MSATS but should not include the mechanism, recognising that the MFIN has been used as an example. An alternative to provide the notification and visibility efficiently to all market stakeholders, would be to use an MSATS mechanism. This would be better defined within AEMO procedures. • Plan guideline/checklist – A guideline/checklist developed and made available by the team approving the Plan, defining what elements need to be considered in the Plan and what criteria needs to be met, to obtain approval. This approach would decrease the administrative effort and increase the timeliness in approving the Plan. PLUS ES supports the AEMC's determination that the AER would be the most appropriate party to conduct the assessment for the reasoning provided.
Q3. LEGACY METER RETIREMENT THROUGH RULES OR GUIDELINES (OPTION 2)	
1. Do stakeholders consider option 2 feasible and appropriate for accelerating the deployment of smart meters? Are there	Whilst Option 2 delivers a process similar to Option, with a modification to responsibilities, it will not support the agility to accommodate unforeseen circumstances and could potentially increase the administrative effort.

[3] Metering providers are aware of their executed commercial agreements and could estimate the potential volume which may be assigned to them.

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aspects of option 2 that would benefit from further consideration?	For Option 2 to deliver the efficiencies of Option 1, it would require: • A more complex and prolonged engagement with stakeholders and/or • Generic rules/guidelines which would increase the probability of varying participant interpretations, effectively decreasing efficiencies. Amendments to rules/guidelines would normally require a consultation timeframe adding further delays and increasing resourcing efforts.
2. Are market bodies the appropriate parties to set out the legacy meter retirement schedule?	Market bodies are not the appropriate parties to set out the legacy meter retirement schedule as: • They do not have the insight the DNSPs have of their network requirements. • Lack visibility to the operational details/challenges which a metering provider or DNSP may have to be able to drive the most efficiencies through correct prioritisation of network and geographical requirements. ' • Adds another stakeholder to the scheduling requirement and introduces another dependency reducing efficiencies.
3. If option 2 is adopted, should the meter retirement schedule be located in the rules, or guidelines developed by the AER or AEMO?	Having the schedules in the rules or as guidelines developed by AEMO or AER adds another level of administration as any changes would potentially require a consultation to develop and/or amend. This would unnecessarily increase the timeline in either option. If option 2 is adopted guidelines should be developed by AEMO as: • They develop and maintain market operational procedures and guidelines, engaging market participants. • The AER will be the party governing compliance and it may be perceived as a conflict of interest if they are also the party developing the schedule.
Q4. RETAILER TARGET (OPTION 3)	
1. Do stakeholders consider option 2[5] is feasible and	We agree with AEMC's position that this option is not viable. Retailers would deliver their own deployment plan and would not group meters

[5] PLUS ES assumes this question incorrectly references option 2 since it pertains to option 3.

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appropriate for accelerating the deployment of smart meters? Are there aspects of option 2 that need further consideration?	as efficiently as a DNSP plan. Retailers only have visibility to their customer sites and do not have visibility of other retailer's deployment schedule.
2. If this option is adopted, what are stakeholders' suggestion on how retail market dynamics could be taken into consideration in both setting the uptake targets and monitoring performance?	If this option was to be adopted, targets and monitoring performance should consider the actual volume of smart meter installations the retailer undertook within the reporting period, irrespective if the customer of that site has churned to another retailer. This would ensure a fair and equitable distribution of smart meter deployment between retailers and remove the variable of customer churn.
3. Should the rules or a guideline outline only a high-level target (universal uptake by 2030 taking into account practicality of replacements) or more granular targets or interim targets?	For any of the options, high level targets should be set as well as more granular interim targets to ensure an efficiently distributed deployment to mitigate back ending large volumes of meters. (Refer to PLUS ES' previous comments for more detail).
Q5. STAKEHOLDERS' PREFERRED MECHANISM TO ACCELERATE SMART METER DEPLOYMENT	
1. What is the preferred mechanism to accelerate smart meter deployment?	PLUS ES's preferred mechanism is Option 1 – the DNSP with engagement from retailers and MPs to develop the Plan to retire their legacy meter fleet.
2. What are stakeholders' views on the feasibility of each of the options as a mechanism to accelerate deployment and reach the acceleration target?	PLUS ES' views on the feasibility of each of the options: • **Option 1** is the most pragmatic and efficient mechanism to accelerate deployment • **Option 2** whilst feasible in achieving acceleration targets, would deliver a less adaptable option, **Option 3 and 4** would not deliver efficiencies nor sufficiently support stakeholders to meet acceleration targets.

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3. Are there other high-level approaches to accelerating the deployment that should be considered?	PLUS ES has no further approaches.
B. REDUCING BARRIERS TO INSTALLING SMART METERS AND IMPROVING INDUSTRY COORDINATION	
Q6. FEEDBACK ON NO EXPLICIT OPT-OUT PROVISION	
1. Do stakeholders have any feedback on the proposal to remove the opt-out provision for both a programmed deployment and retailer-led deployment?	PLUS ES supports the removal of the customer opt-out provision for both a programmed and retailer-led deployment. The requirement will have to be unambiguous and clear to deliver the intended outcomes, especially allowances for any exceptions. Retailers have taken varying approaches to current requirements, even extending the current opt - out option to malfunctioning/non-compliant metering. Malfunctioning meter replacements incorporated in the accelerated program should not be eligible to social licensing exceptions such as customer refusals.
2. Are there any unintended consequences that may arise from such an approach?	There will always be customers who refuse smart meters. Unintended consequences of removing the ability of the customer opting out of a smart meter installation could include: • Customers refusing access to the metering installation for meter reading and maintenance • Threatening the safety of field technicians when they attend the site • Tampering with the communications assets of the meters The AEMC needs to consider including within the framework an ability to: • Provide a pathway for second/multiple attempts, as required • Enable market visibility of customer refusal sites • Introduce a process/exception allowance for onsite customer refusal of smart meters to support a field technician's safety • Incentivise customers directly/indirectly to accept remote

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	communicating smart metering installations
Q7. REMOVAL OF THE OPTION TO DISABLE REMOTE ACCESS	
1. Do stakeholders consider it appropriate to remove the option to disable remote meter access under acceleration?	PLUS ES do not support disabling remote communications on smart metering but experience has shown that some customers will insist on this option. The rules must allow a way for those customers refusing remote communications, otherwise they may resort to more drastic measures such as damaging the asset.
Additional points:	
Retailers only need to provide one notice for retailer-led deployments outlining relevant information for customers *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	PLUS ES supports the requirement to provide one notice and recommend the following: • Timeframe for the notification to be provided - no greater than 30 business days[6] and no less than 10 business days. • For deployment efficiency [redacted] – the rules should be amended to allow a default **deployment window**, rather than a specific date. The rules should also allow for the customer to request a specific date. • The timeframe window for any programmed smart meter deployment, accelerated or otherwise, to be extended to 10 business days, including the timeframe provided to customers in the notification.
Q8. PROCESS TO ENCOURAGE CUSTOMERS TO REMEDIATE SITE DEFECTS AND TRACK SITES THAT NEED REMEDIATION	
1. Do you consider the proposed arrangements for notifying customers and record keeping of site defects would enable better management of site defects?	Current visibility and management of customer notifications with respect to site defects is minimal and varies according to participant processes. PLUS ES supports a consistent site defect process will enable better management of site defects. PLUS ES recommends the following to further enhance and drive operational efficiency. • The obligation to leave the defect notice with a customer should be on the MP not the MC as they are responsible for the site

[6] As opposed to the 60 business days timeframe proposed by the AEMC in the Draft Report.

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	activities.
	• Site defect status should be made available to the market no later than 5 business days from been identified in the field.
	• The retailer should manage the recording of the information in MSATS and manage the customer interface and engagement – this would include applying and removing (when the customer advises the site has been remediated) the site defect status.
	• Proposed timeframes to follow up with customer are too long especially in an accelerated deployment program where resources have been procured for a specific location. To support an efficient process:
	  ○ The retailer should send the notice within 5 business days of receiving the notification from the MP. This will then require enhancements to the B2B mechanisms to drive efficiencies. i.e. Not complete reason code on Service orders for the retailers to automatically consume.
	  ○ The retailers should follow up within 4 weeks of the first notice being sent if the customer has not contacted them
	• The process proposed in the draft report states that the customer notifies the retailer of site remediation. Due to the downstream deployment implications and the dependency on a customer to call the retailer, we propose that the obligation is on the retailer to follow up with the customer rather than wait for the customer to contact them.
	• The MSATS step of the process calls for the replacement of the NMI. For clarity the NMI does not get replaced, it is the meter that requires replacement.
	• We recommend that the MSATS updates happen at the beginning of the process and as required not at the end of the process.
	• For clarity we support recording the unsuccessful remediation of a site in the retailer's next AER quarterly performance report is appropriate for the end of the process. This action should be mutually exclusive from the MSATS update requirement.

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	• Site defect customer notification – the content and mandatory information should be defined by the rules for consistent messaging similar to the approach applied to planned interruption notices. • Tenant vs Landlord – The account holder could be a tenant and not responsible for the remediation of the site defect – consideration needs to be given to making the landlord aware of the site remediation. For example, incorporating advice in the notices, for tenants to forward the notices to the landlord or the landlord's agent, including the defect notices received on the day of the site visit.
Additional Points	
Timelines for resolved site defects	Legacy meter retirement sites which have had their site defects remediated should not be reclassified as customer initiated, which would impose a 15 business day timeframe on the MP and drive deployment operational inefficiencies. The above would apply to all site exception conditions such an access issues etc – not only site defects. The MP will want to exchange the legacy meter as soon as practicable, especially when resources are available but not within the constraints of 15 business days.
Jurisdictional financial support	PLUS ES supports that jurisdictions should implement a scheme to provide financial support to those customers which cannot afford to remediate their sites to enable the installation of a smart meter. Deployment efficiencies are gained through reduced aborts for site fixes and the smart metering installed within the schedule timeframes.
Jurisdictional support for tenanted sites	PLUS ES also supports opportunities for jurisdictions to ensure that tenants of sites requiring remediation are not unintentionally discriminated against.
Safety vs non-compliance to current standards	The Draft Report makes mention of material defect. This should be defined within the rules at a high level. We recognise that site remediation requirements fall within the jurisdictional regulations and experience has shown that existing or

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	latent conditions which may not be up to current standards will be classified as a defect and still require the customer to remediate. PLUS ES recommend that for the installation of a smart meter at an existing installation, to replace an end-of-life network meter (i.e. replacement not instigated by the customer), the requirement should be to install the meter in accordance with key safety principles and AS3000 Wiring Rules repair principles - but stop short of requiring the installation to be upgraded to an "as new" installation. For example, • If the existing metering isolation point is safely accessible and serviceable, then it should not need to be relocated if the latest jurisdictional rules require it to be at a specific height. • The existing metering enclosure that was acceptable at the time the property was established, should not need to be replaced to match the latest jurisdictional rules, so long as the enclosure is assessed to be safe and serviceable. There is due diligence for the REC to take necessary action and ensure a site is safe with respect to AS3000 wiring standards.
Q9. IMPLEMENTATION OF THE 'ONE-IN-ALL-IN' APPROACH	
1. Would the proposed 'one-in-all-in' approach improve coordination among market participants and the installation process in multi-occupancy sites?	The proposed process is not a perfect process, but it delivers efficiencies and improvements to current practices. While some complexity still exists, the end customer receives benefits as all the meters and the supply interruption will be coordinated for the one visit. Market participants will still need to work together to ensure: • Clarity and confidence in the responsibilities and timeframes of the market participant roles • The DNSP – is the common participant across all NMIs at the site of the multi occupancy, hence the DNSP is best positioned to provide the Planned Interruption Notice (PIN) to the customer. • Retailers, metering parties and DNSPs are provided clear timeframes associated with their tasks • The metering provider which originally discovers the multi occupancy site with shared fuses will perform an initial

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<td>assessment of the site to mitigate downstream impacts. i.e. assessing the meter panel, size and condition[7] etc</td>
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<td>2. Are the time frames placed on each market participant appropriate for a successful installation process of smart meters?</td>
<td>The timeframes are appropriate with the following comment for clarification:

Fig B.3 – the first step should be the retailer raising a TIGS to the DNSP, following a notification from the MP of a shared fuse; including an appropriate timeframe. The trigger of this process is the MP informing the retailer of a shared fuse and the non-completion of the original service order.

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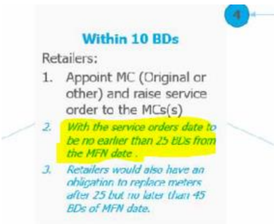
<td>3. Are there any unforeseen circumstances or issues in the proposed installation process flow and time frames?</td>
<td>The proposed installation process flow could lead to the following issues:

Coordination between multiple MPs arrive on site.
Fig B.2 –



Bullet point 2 of figure B.2 should indicate that the service order must include the scheduled date of the MFIN which the DNSP has determined in Step 3 with the original MC. This should be treated as an appointment. If a retailer's multi occupancy customer does not agree to the metering installation on the scheduled date, the retailer will have to raise a separate TIGS to the DNSP. It is worth reinforcing that the customer who has refused the meter installation on the scheduled date will still incur the supply outage due to the shared fuse.</td>
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<td>4. How should DNSPs recover costs of temporary isolation of group supply from all retailers?</td>
<td>No comment</td>
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<tr>
<td>5. Can the proposed role of the DNSP in the one-in-all-in approach be accommodated by</td>
<td>No comment</td>
</tr>
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[7] This may require the metering parties developing a standard checklist and agreeing to its implementation.

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the existing temporary isolation network ancillary services?	
6. Which party should be responsible for sending the PIN in the context of the one-in-all-in approach?	The DNSP is the common participant for all the NMIs at the multi occupancy site with the shared fuse. Since the DNSP is also the party which will be predominantly accountable in determining and scheduling the date of the temporary isolation, they should be the party providing the PIN to the customer. Additionally: • The multi occupancy customers are also the DNSPs customers through connection agreements • In the likelihood that a retailer does not schedule a meter replacement for their multi occupancy customer, and the temporary isolation still proceeds, the customer will have received their PIN as they will still be impacted by the outage. • Having the DNSP send the PIN directly streamlines the process, removing the retailer from the notification process.
Additional Points	
PIN notifications	There has been some confusion and misalignment between participants on which participant should provide a PIN to the customer. In some instances, the DNSP may notify the customer and then the retailer with their own interpretation of compliance will also send a PIN to the customer. Additionally, some notifications of TIGS schedule dates by the DNSP will not allow the retailer or the MP to provide a PIN within the required timeframes. Explanations regarding these variances are due to the definition of customer initiated and/or distributor planned interruption. To deliver a more efficient process and clarity of the accountabilities and responsibilities across all parties involved in the planned outage, PLUS ES proposes the following: • Amend the definition to clarify that if a DNSP interrupts the supply for metering works, they are responsible for provisioning the PIN to the customer, irrespective if it is customer initiated or planned network interruption.

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	• If an MP interrupts the supply and the DNSP is not required/involved in the interruption of the supply the retailer is required to provide the PIN. *Refer to PLUS ES' Direction Paper submission pg. 33-34, for more detail.*
DNSP co-ordination	Similar to the multi occupancy process there must be a standard process which supports efficient and timely co-ordination, where the DNSP is required to complete a supply augmentation and/or isolation activity, and where metering activities have a dependency on the DNSP activity. The current challenges experienced by PLUS ES include: • Some DNSPs do not provide enough notification of the scheduled time for the MP to attend. In some instances timeframes have been no greater than 24 hours. This is an inefficient process and has downstream impacts in scheduling resources, missing the scheduled dates/appointments, and potentially rescheduling more than one job to accommodate the scheduled date of the DNSP. • Some DNSPs provide the scheduled dates only to the retailer, with potentially no notification to the MP. This adds a dependency on a 3rd party, the retailer, to forward the communication and in a timely manner. PLUS ES recommend that an obligation is placed on the DNSP to notify the MP of scheduled supply outages or completion of dependent activities (Retailer initiated or DNSP planned). This notification is to be provided via existing B2B market tools which enables automation of processes. The timeframes should at a minimum allow for the MP to meet their obligations and/or schedule their resources for the metering installation. Additionally, another option would be for the DNSP to also provide metering parties appropriate access to their portals (where portals are available).
C. IMPROVING THE CUSTOMER EXPERIENCE IN METERING UPGRADES	
Q10. STRENGTHENING INFORMATION PROVISION TO CUSTOMERS	

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1. Do you have any feedback on the minimum content requirements of the information notices that are to be provided by Retailers prior to customers prior to a meter deployment?

Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law

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PLUS ES proposes:

- Excluding the consumer's retail contract/network tariff information from the smart meter customer notice, if social licensing is to be achieved for smart meter deployment –
  - Latent basic data could potentially shed a negative light to the customer with respect to their smart meter tariffs.
  - Supporting transitional arrangements an alternative option would be that the customer was advised there would be no changes to the retail tariff.
- Proposed terminology for assertiveness, customer acceptance and efficiencies:

Table C.1: Proposed line items for the two proposed measures

<table>
<tr><th>INFORMATION RECOMMENDED FOR NOTICES</th><th>INFORMATION RECOMMENDED FOR THE SMART ENERGY WEBSITE</th></tr>
<tr><td>• The reasons for the proposed new meter deployment (planned, failure, retailer-led or new connection)
• An indicative timeline for when the customer would receive the smart meter (this can be a date range)</td><td>• The benefits of smart meters to customers.
• The benefits of smart meters to the</td></tr>
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  - *The reasons for the proposed new meter* – amend to remove the word **proposed.** [redacted]

Table C.1: Proposed line items for the two proposed measures

<table>
<tr><th>INFORMATION RECOMMENDED FOR NOTICES</th><th>INFORMATION THE SMART ENI</th></tr>
<tr><td>• The reasons for the proposed new meter deployment (planned, failure, retailer-led or new connection)
• An indicative timeline for when the customer would receive the smart meter (this can be a date range)</td><td>• The benefits c customers.
• The benefits c</td></tr>
</table>

  - An indicative timeline for when the customer would receive – amend ***would*** to ***will***
  - This can be a date range – as per previous feedback this **should** be a date range[8] by default. A specific date should only be available upon the request of a customer due to customer access issues or customer personal circumstances.
  - Rights and responsibilities – need to call out the customer's obligation to have compliant metering, hence they must

</td>
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</table>

[8] PLUS ES recommends and supports that the deployment timeframe for mass volumes at a minimum, should be extended from 5 business days to 10 business days.

	accept the meter exchange, e.g. malfunctioning/non-compliant meters. Additionally, include wording to emphasise that the switchboard is the customer's infrastructure. E.g. a smart meter installation on your switchboard etc. ○ Customer Notice vs PIN – PLUS ES supports the enablement for the customer notice and the PIN to one notification. Conversely, clarity needs to be provided as a PIN is not required when the customer agrees to the outage. Furthermore, sometimes the timeframes to complete a meter installation may have less than 24 hr turnaround. PLUS ES recommends any obligation pertaining to the provisioning of the customer notice: ▪ Is independent of the obligation to provide a customer a PIN ▪ Defines timeframes to provide the customer notice as prior to the installation, on the day of, or at a date no later than 'X' business days post the smart meter installation. This will ensure that the customer notice does not become a barrier to smart meter installation scheduling, especially if this notice is to be provided for all smart metering installations.
2. Are there any unintended consequences which may arise from such an approach?	The following consequences may arise: • Our experience has shown that customers generally do not remember notices provided 3 months from the meter exchange date. Hence, the timeframe for the notice to be sent should be amended from 60 business days to a maximum 30 business days prior. • Including the customer's retail/network tariff details in the notice at this early stage of the installation process, without supporting interval time of use data, could present a barrier to the customer accepting the smart meter installation. (Refer to comments in the previous question)
3. Which party is best positioned to	PLUS ES believes that the Clean Energy Council would be best placed at a national level to maintain the smart energy website, which retailers

develop and maintain the smart energy website?	could refer to in their notifications. Alternatively, industry bodies such as the Australian Energy Regulator (AER) or the Australian Energy Market Operator (AEMO) as people are more likely to have heard of them. The party should be an existing body and not a new entrant.
Q11. SUPPORTING METERING UPGRADES ON CUSTOMER REQUEST	
1. Do stakeholders support the proposed approach to enabling customers to receive smart meter upgrades on request?	PLUS ES supports the proposed approach, if: • The existing meter on site is a Type 5/6 (legacy) as it will enhance the process of the smart meter deployment to reach a faster conclusion • the customer is seeking an upgrade to their metering installation due to supply alterations performed at their site.
Q12. TARIFF ASSIGNMENT POLICY UNDER AN ACCELERATED SMART METER DEPLOYMENT	
1. Which of the following options best promotes the NEO: **a. Option 1: Strengthen the customer impact principles to explicitly identify this risk to customers.** **b. Option 2: Prescribe a transitional arrangement so customers have more time before they are assigned to a cost-reflective network tariff.** **c. No change: Maintain the current framework and allow the AER to apply its discretion based on the circumstances at the time.**	Option 2 (Prescribing a transitional arrangement) has the potential to best promote the NEO. Customers who do not have data to review and analyse their energy consumption will not be able to identify the impact of a tariff change. Additionally, without the data, a customer interested in lowering their energy costs will not be able to determine how to change their behaviour to achieve the outcome.
2. Under options 1 or 2, should the tariff	PLUS ES supports that no customer should be excluded from Option 2

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assignment policy apply to: **a. all meter exchanges – for example, should the policy distinguish between customers with and without CER?** **b. the network and/or the retail tariffs?**	(Transitional arrangements). The policy should allow customers to have a choice if they participate in the transitional arrangements. For example, a customer may want to take advantage of the appropriate tariff/product plans available to them because of their CER assets. Access to retail/network reassignments should not be constrained by any transitional arrangement policies.
3. What other complementary measures (in addition to those discussed above) could be applied to strengthen the current framework?	No comment.
Additional Points	
Meter Malfunction Exemptions	PLUS ES does not support 70 business days from when the metering provider has been notified/received a service order, is sufficient to accommodate volumes for family failure packages especially during timeframes where field resources are undertaking: • BAU meter exchanges or new connections • Accelerated smart meter deployment and • Retailer Led Deployment To plan, schedule, ramp up resourcing and deploy meter exchanges for family failure meters is difficult to achieve within 70 business days. This timeframe needs to be extended to a minimum of six months; ideally one year.[9] Alternatively, where the family failure are legacy meters the DNSP should include them in the next batch release of retired meters and amend the next release accordingly, giving priority to the family malfunctioning meter fleet over the 'retired' legacy metering whilst making the necessary adjustments to their Plan.

[9] A >12 month timeframe is sought for family failures due to the potential volumes which could be released at once. For example, in one instance a DNSP released 250K meters. This scenario is very possible with smart meter families also. When a smart meter family fails, it would impact several MPs depending on which MPs deployed that meter. The timeframe would be required to accommodate all the associated challenges involved in commencing such a program of work.

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	We acknowledge that there will be site remediations, access issues, customer refusals and sites not ready for a portion of these meters and support that these sites must be managed by exceptions to the timeframes. Once remediated, these timeframes are to recommence and should not be reclassified to a 15 business day timeframe. There must be a mechanism to provide visibility to retailers and DNSPs simultaneously. The proposed timeframes would also be applicable to a contestable MPs own meter family failure. Consideration needs to be given to the accelerated rate which meters are being and will be rolled out. The acceleration timeframe proposed is an allowance of 12 months. If a smart meter family failure occurred, a similar timeframe, if not more, may be required to replace the volume of smart meters from the failed family. For example, a meter family may be deployed over a few years. If the meter family failed, those volumes **may not** be replaced within the proposed 70 business days nor within a 12 month timeframe if the initial deployment timeframe was 2 years. Factors which would need to be considered is the volume of failed meters and the necessary adjustments to BAU resourcing and asset procurement.
D. OPPORTUNITIES TO UNLOCK FURTHER BENEFITS FOR CUSTOMERS AND PARTICIPANTS	
Q13. MINIMUM CONTENTS REQUIREMENT FOR THE 'BASIC' PQD SERVICE	

PLUS ES has the following feedback on this topic:

- MC vs MP/MDP:
    - Obligations for commercial agreements with respect to provisioning Power Quality data should be placed on the responsible parties who manage the assets and the data as they will be investing in their assets, processes, and systems to meet the Power Quality requirements. These parties are the MP/MDP.
    - The proposed will also support and streamline the bilaterally agreed process especially where more complex engagement models exist in the current market between metering parties.
- Obligations to provision Power Quality data to DNSPs –
    - For the most cost efficient service this basic service must apply to all eligible NMIs. Use cases for neutral integrity would support the provisioning of the Power Quality data for all

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NMIs ○ Frequency – PLUS ES supports the 24 hr provisioning of the data: ▪ Aligns with the current frequency in provisioning meter data to the market ▪ The data is historical irrespective if it is delivered every 24 or 6 hour intervals. That is, delivering for all NMIs the data every 6 hours will not define it as near real time. ▪ 24 hr delivery provides more efficiency and lower costs ▪ For specific use cases – the DNSP always has the option to negotiate Power Quality data to support their needs. ○ The effective date of Power Quality data service to the DNSP should be at a minimum 12 months from final rule amendments. • Type 4 meters – Services should not be segregated in accordance with customer segmentation. PLUS ES supports the scope to: ○ Not include MRAM metering and ○ Align to the metering requirements of 5MS. That is, at a minimum Type 4 metering installed on or after 1/12/2018 and upgraded to 5MS. • Retention of Power Quality data – PLUS ES supports a minimum retention period of the Power Quality data. If there is a requirement for the requestor to have the ability to re -request data; a request response mechanism is required. ○ Raw Power Quality data will be provided, no validation/substitution activities will be performed • Meter ping and enquiry service – PLUS ES supports obligations relating to the provisioning of these services: ○ Are enabled within the rules and separate from any obligation to provide Power Quality data • Beneficiary pays – ○ Access to the services and remuneration to be negotiated via bilateral commercial agreement ○ The metering provider will have to invest considerable fixed and variable costs to provide the infrastructure and support the ongoing operational requirements for provisioning these services.

1. Should the 'basic' PQD service deliver any other variables besides voltage,	Increasing the number of channels delivered as a Basic PQD service will increase the costs. Through the various workshops held by the AEMC to define a Basic PQD service, it was determined that the

current, and phase angle?	currently proposed parameters voltage, current and phase angle were sufficient to support many use cases for all DNSPs. Provisioning of further parameters is possible, though the benefits may not justify the increased costs. There are additional impacts that need to be considered and measured against the costs: • The information one network may require may not be applicable for another network. Proposing additional variables for a basic service has to meet the criteria of all recipients. • Increasing the volume of data will also impact the delivery time not only for PQD but also for market settlement data. These are limitations driven by telecommunications networks. If the defined basic PQD service does not fully meet a DNSP's specific or unique requirement, there is scope for DNSPs to bilaterally agree. The rules should enable this pathway.
2. Does the 'basic' PQD service require any further standardisation, e.g., service level agreements? If so, where should these service levels sit? *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	In the current model, retailers and metering service providers have bilaterally agreed service level agreements, which meet their requirements and enable market settlements. PLUS ES supports that a similar path should be adopted for the basic PQD service. If it is determined that service levels should be introduced, the following points should be considered: • Market settlement data to be prioritised. Service level agreements will have to be lower than those of meter data delivery. The basic PQD is not a real time deliverable and there is scope to be flexible as the data will be historical when received. • Latency/Time limits – delivery timeframe expectations of 1 hr after midnight is not achievable with the large volume of data being sent including but not limited to meter data. [redacted]

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	[redacted]
3. Should the Commission pursue a data convention to raise the veracity of 'basic' PQD?	PLUS ES is of the view that the accuracy of the PQD should align with the pattern approval of the meter. The metering standards and the National Measurement Institute (NMI) Pattern Approval requirements don't specifically cover the accuracy of measurement of power quality information. However, because whole current smart meters are at least Class 1% devices for kWh measurement. The measurement of PQ data such as voltage and current would be a similar, if not more accurate measurement as they come from the same source - the meter is sampling voltages and currents and using this measurement to calculate kWh and kVArh data. The focus of standardising a data convention for PQ data should be to ensure that the definition of each required measurement and how it is presented is agreed standardised, so that the recipient can interpret the data in the same way, irrespective of who sends it. We shouldn't mix this up with the accuracy of the actual measurement, as this should be accepted as whatever accuracy the meter can deliver - and given the kWh/kVArh accuracy of the meter, the PQ data would be more than accurate enough for network planning etc.
Q14. UTILISING THE RIGHT EXCHANGE ARCHITECTURE FOR THE 'BASIC' PQD SERVICE	
1. Should the industry use the shared market protocol? If not, why? *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	Some DNSPs have already moved forward and are receiving access to basic PQD services. For this reason, PLUS ES proposes that the mechanisms for delivering these services should be bilaterally agreed between the provider and the requestor. The rules should allow: • The interested parties to choose the exchange architecture – noting in this instance reference to Basic PQD services is associated with the DNSP • Shared Market Protocol (SMP) and Point to Point (P2P) direct exchange should be available– Not constrained to a specific solution. [redacted]

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2. Should stakeholders exchange PQD directly, using NER clause 7.17.1(f)?	NER Clause 17.7.1 (f) states: (f) *B2B Parties* may, on such terms and conditions as agreed between them, communicate a *B2B Communication* on a basis other than through the *B2B e-Hub* provided the *B2B Communication* is otherwise made in accordance with the *B2B Procedures*. PLUS ES support sharing data in accordance with the NER clause 7.17.1(f), with the caveat that the B2B Procedures also support bilaterally agreed direct PQD exchange.
3. If so, should the Commission prescribe this in the rules, or could this be by agreement between parties?	The rules should enable a pathway for bilateral agreements between parties.
Q15. PRICES FOR POWER QUALITY DATA SERVICES	
1. Is it sufficient for the prices for PQD services to be determined under a beneficiary pays model, especially with a critical mass of smart meters? *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	PLUS ES supports it is sufficient for Power Quality data services to be determine under a beneficiary pays model. [redacted]

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	[redacted]
2. Are alternative pricing models, e.g., principles-based or prescribing zero-cost access, more likely to contribute to the long term interest of consumers?	PLUS ES does not support that alternative pricing models are more likely to contribute to the long term interest of consumers: • Zero-cost access - The contestable service providers of Power Quality Data services must be remunerated for the investments and the services they provide. The contestable service provider will not be able to provide the services due to the costs required to operationalise or have the funding to invest in research and development to continue to support the fast evolving electricity industry. • Principal based – This approach will likely lead to inequitable cost outcomes between parties and reduce competitive tensions to provide additional services. It would hinder competitive market dynamics. As the industry moves towards additional revenue streams from data provided outside of current regulated market data, competitive forces between metering providers will shift cost towards parties that benefit from this data. This is already happening in the market today and could be stifled with a principle-based pricing approach.
Q16. REGULATORY MEASURES TO ENABLE INNOVATION IN REMOTE ACCESS TO NEAR-REAL-TIME DATA SOONER	
Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law Real time access to retailers is cost prohibitive – [redacted] Whilst enquiries are made, retailers are reticent to pay for near real time data on an ongoing basis and to date have not identified use cases to justify the costs.	
1. Do stakeholders support the Commission pursuing enabling regulatory measures	PLUS ES does not support the Commission pursuing regulatory measures for remote access to near real time data in the immediate future: • The consumer's awareness of smart metering, it's capabilities and

for remote access to near real-time data? If so, would it be suitable to: **a. Option 1: require retailers to provide near real-time data accessible by the consumer in specific use cases (while allowing them to opt-out).** **b. Option 2: allow customers to opt-in to a near real-time service via their retailer for any reason.** **c. Option 3: promote cooperation and partnerships between Retailers and new entrants for near real-time data services, e.g., in a regulatory sandbox.**	deliverables especially remote access to near real time data is rudimentary. • The provisioning of remote near real time data is cost prohibitive. • The use case/s for such a capability is unknown to qualify the cost burden on the industry • The emerging Consumer Energy Resources (CER) market requires real time access to data not near real time which can be achieved in a more cost efficient manner • Current regulations do not preclude a retailer or other access party to request the service • May potentially require changes to the metering specifications, imposing a futureproofing cost in an economy already grappling with high inflation and increasing energy costs. For the reasons above, if the AEMC were to pursue enabling some regulations, Option 3 would be the most appropriate for the current environment as it would enable innovation and deliver outcomes to support future enhancements to the regulatory framework.
2. If so, could the Commission adapt the current metering data provision procedures?	PLUS ES recommends that the scope, solution, and requirement should be defined in more detail before determining if the current meter data provisioning procedures could be adapted.
3. Are there any standards the Commission would need to consider for remote access? E.g., IEEE2030.5, CSIP-AUS, SunSpec Modbus, or other standards that enable 'bring your own device' access.	*Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*
4. What are the new and specific costs that would arise from these options and	*Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31*

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are they likely to be material?	*and 48 of the National Electricity Law*
Q17. REGULATORY MEASURES TO ENABLE INNOVATION IN LOCAL ACCESS TO NEAR-REAL-TIME DATA SOONER	
1. Do stakeholders support the Commission considering regulatory measures for local access to near real-time data? If so, would it be suitable to: **a. Define a customer's right in access the smart meter locally for specific purposes?** **b. Outline a minimum local access specification, including read-only formatting and uni-directional communications? Are there existing standards that MCs can utilise, for example, IEEE2030.5, CSIP-AUS, or SunSpec Modbus?** **c. Codify a process for activating, deactivating, and consenting to a local real-time stream? If so, could the Commission adapt the current metering data provision procedures?**	*Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*
2. Are there any other material barriers that the Commission should be aware of?	*Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*

G	ADDRESSING SHORT-TERM COST IMPACTS
Q18. ADDRESSING SHORT TERM COST IMPACTS AND ENSURING PASS THROUGH OF BENEFITS	
1. Are stakeholders concerned about the risk of short-term bill impacts as a result of the accelerated smart meter deployment? To what extent would the above offsetting and mitigating factors address this risk?	No comment.
2. If stakeholders are concerned about residual cost impacts, what practical measures could be put in place to address these risks?	No comment.
3. What are the implications for AER revenue determinations for the upcoming New South Wales, Australian Capital Territory and Tasmania DNSP regulatory control periods? Is there a risk that network cost savings as a result of the accelerated smart meter deployment will not be fully passed through to consumers under the regulatory framework?	No comment.
ADDITIONAL ITEMS FOR AEMC'S CONSIDERATION	

Customer access issues *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	Meeting the MC and MP obligations for metering is becoming increasingly difficult due to customer's access issues. The metering service providers have a dependency on participants such as the Retailer to provide support. Whilst retailer contracts do include terms that the customer must allow access, it is difficult to enforce due to the inherent risk that the customer could churn to another retailer. PLUS ES has raised this item previously in industry forums. [redacted] PLUS ES is seeking a pathway to support the MC/MP in meeting their obligation.
Remote energisations	• NER clause 7.3.2 (i)(2)(ii) states: The *Metering Coordinator* at a *connection point* with a *small customer metering installation* must *not arrange a disconnection except where such disconnection is effected* via *remote* services • NER clause 7.3.2 (i)(3)(ii) states: The *Metering Coordinator* at a *connection point* with a *small customer metering installation* must *not arrange a reconnection except where such disconnection is effected* via *remote* services There are varying interpretations in the industry of how the word remote is defined. Some interpret it as 'over the air' communication or off the premises activity. Such a definition assumes that if a remote energisation cannot be completed or fails, the MP cannot effect a local metering energisation i.e. open/close the contactor manually using a probe. This introduces inefficiencies in the process which will ultimately result in a poor and more costly customer service. PLUS ES proposes that the words *remote access* in the above mentioned clauses are replaced with the words *the meter* or *metering installation.*
High Voltage (HV) Current Transformer (CT) & Voltage Transformer (VT) Accuracy Testing	Whilst this predominantly relates to HV CT & VT Accuracy Testing - but should also cover LVCT Accuracy Testing and, Meter Accuracy Testing. All these activities are MC compliance obligations, cost money and usually cause temporary supply interruption. The MC is constrained

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Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law	from completing this work because the retailer/large customer who appoints, contracts and pays the MC for the broader metering service, is not obliged to include these testing functions in the terms of the MC agreement. As a result, the compliance obligation is not completed, and the MC is in breach of the Rules and does not have any avenue to remedy the situation. PLUS ES is seeking assistance from the AEMC to enhance/amend the rules as applicable to support achieving compliance with our obligation and ensuring from a safety perspective, we have access to perform the testing required. • HV sites being large customers may either have: a) A direct contract with the MC or b) A contract with the retailer who then appoints the MC • The customer when pressed to agree to HV testing will churn MC and/or retailer, and this loop can continue so the HV Testing is overdue. In addition to safety concerns, HV meter testing also ensures that the asset is recording accurate data. Erroneous data could have an impact on the customer and market settlements, especially Unaccounted for Energy (UFE). Numerous discussions and investigations have determined that unless obligations are reflected in the rules, there are no mechanisms to regulate the compliance. [redacted] However, customers do have a contractual relationship with the retailer. PLUS ES proposes that the conditions of the MC appointment should also reflect the above obligations. This would oblige the retailer/large customer with a Direct Marketing Agreement (DMA) to comply with these obligations as part of the agreement with the MC, so we would be covered. [redacted] There are Rules obligations that are 'automatically' complied with

	(such as delivery of data, and time taken to install a meter) because the retailer wants these as well. However the same cannot be said for metering testing and inspection obligations – as it doesn't affect the retailer's compliance, which is why it is overlooked. As an example, PLUS ES proposes NER clause 7.6.1 has an additional clause added: *(c) The terms of the appointment must include reasonable commercial terms that recompense and support the achievement, in full of all metering installation test and inspection obligations of the Metering Coordinator under the Rules, the procedures authorised under the Rules and the Metering Coordinator's AEMO approved Metering Asset Management Strategy.*
Testing requirements for smart metering *Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*	PLUS ES supports the utilisation of the remote conditioning monitoring capabilities of the smart meter to replace or significantly reduce the requirement to physically visit a smart meter. The objective is to deliver a more efficient process resulting in the reduction of the ongoing maintenance costs. PLUS ES proposes the Schedules in Chapter 7 are revised to replace scheduled testing and inspection with remote condition monitoring. [redacted]

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Meter Replacement following a natural disaster	Recent natural disaster events identified opportunities for the process to be improved. Some challenges encountered include: • Meters are bypassed and not identifiable. Due to the potential volumes of these meters there are instances that these meters may be missed and not identified for a protracted timeframe. • NMIs are de-energised or abolished in the field and participants are not consistently notified of the change in status.
Power industry keys	PLUS ES recognises that access to power industry keys could present security challenges especially for keys which provide access to network assets such as substations. The current process is inefficient, creates delays and delivers poor outcomes to all stakeholders. PLUS ES supports an industry led solution to the provisioning of industry keys to metering parties to enable MPs to access meters. As this issue has been tabled at industry for several years with no significant resolution, PLUS ES is proposing for a framework to support MPs getting access to these metering installations. Note: ACT and Qld – have a mechanism to provision keys, although this is very manual. SA and NSW DNSPs are still providing challenges in obtaining access to metering installations which require power industry keys.
Roles and responsibilities	PLUS ES advocates for changes to roles/responsibilities are needed to improve the consumer experience and reduce market inefficiencies, such as responsibilities and obligations are assigned to the party that is performing the activity etc. Refer to PLUS ES' Direction Paper submission, pg. 35-36.
NMI status	There is a misalignment in industry between the understanding of what constitutes a de-energised NMI and triggers to update the NMI status. There is an increase list of activities which have a dependency on the use of the NMI status field in MSATS such as: • Meter exchanges – Supply is required to complete the metering installation • Remote energisations – if an NMI is de-energised the meter cannot

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	be re-energised • Communication failures – no supply on site equals no communications with the metering installation PLUS ES had raised this issue at industry forums. Recently, obligations were introduced in AEMO procedures to ensure meters with failed communications were investigated within appropriate timeframes. One reason for the failure of communications is that the NMI is de-energised at the connection point not at the metering installation. In most cases, this is an activity not completed by the DNSP. Having identified the status and informed both the retailer and DNSP, PLUS ES has experienced reticence[10] from the DNSPs to update the NMI status in MSATS to reflect the site status, even if there are photos which can be provided to evidence the actual NMI status. Reasons cited include: • The DNSP has not received a B2B SO to de-energise the site • The DNSP were not the party who de-energised the site so they cannot update the NMI status • The third party who de-energised the site must advise them before they can update the site • The retailer must advise them that the site must be abolished • Retailers will not send B2B SO as the DNSPs will charge and then the challenge is cost recovery, especially if there isn't a customer on site. • Safety concerns This is also applicable to abolished sites. Reciprocal concern does not exist for updating the NMI status in MSATS to **active**. Significant resource effort has resulted in minor improvements. A few DNSPs acknowledge they are happy to take reflective action but are not agreeing to a process or providing an efficient timeframe of resolution. Not resolving this impasse in the industry, will continue to deliver the

[10] Industry forum discussions have shown that PLUS ES is not the only participant to experience the reticence to update the NMI status.

	following poor outcomes whilst the volumes will significantly increase with the proposed accelerated roll out. • Customer incurring additional costs for wasted truck visits • MPs incurring additional costs for wasted truck visits or repeat site visits to complete commissioning the meter installation. • Inefficient scheduling of deployment • Inaccurate reflective market settlement data Not being able to achieve a resolution within industry forums, PLUS ES is exploring, if there is a pathway via the regulatory framework to deliver efficiencies and standardisation.
[redacted]	*Confidential information has been omitted for the purposes of section 24 of the Australian Energy Market Commission Establishment Act 2004 (SA) and sections 31 and 48 of the National Electricity Law*

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