Date	Question	Answer	
Please refer Please note 10.41(3)(b).	Please refer to the amendments table published showing revised wording to the Code. Please note: The reference to 10.41(2)(b) within 10.42(1) of the proposed new part 10 (part D) of the rules, should actually be a reference to 10.41(3)(b).		
03/8/10	I can't see anything in the new rules that says "other" components are certifiable, Ron talks about a certification expiry date. Does this mean that other components are certified? When changing the meter and the installation recertified, are the other component expiry dates reset?	Refer to paragraph 9(4)(c) and subclause 13(3) of schedule 10.7 clauses 8 and 9 of schedule 10.8, and also schedule 10.1 table 4, all of part D/10. Certain components have certification validity periods applied to them with definite termination dates; these are measuring transformers, meters, data storage device and control devices. The other components within a metering installation include wiring, fuses/circuit breakers (both of these have requirements under schedule 10.8), possibly wiring junction boxes and testing facilities. What the Code is trying to say is that in the metering installation certification process, the certifying test house must ensure that these "other" components are fit for purpose and comply with all of the Code requirements. The particular Clause in question requires these "other" components to be certified for the certification validity period of the metering installation. When the metering installation is to be re-certified, these components will also need to be recertified in accordance with the Code requirements.	
02/08/10	It is unclear the meaning of the words "other than the following" which appear in clause 13 (3) of schedule. The following referred to are; (a) measuring transformer (b) a meter (c) a data storage device (d) a control device If it does not refer to these components, what components is it referring to?	The listed components have component certification validity periods required under schedule 10.8 of part D/10. The "other" components that comprise a metering installation such as wiring, fuses and test blocks do not have a specified certification validity period in schedule 10.8, and this clause is instructing the approved test house to use the metering installation certification expiry date as the maximum expiry date for component certification for those "other" components Note:The "other" components certification expiry date is the same as the	

Date	Question	Answer
		metering installation expiry date
29/07/10	Clause 23 (2) <b>Meter requirements</b> of Schedule 10.7, appears to be incorrect. I understand the intent is that the meter certification expiry date must be the same date or later than the installation certification expiry date. However, it reads "that the meter certification expiry date must be no later than the end date of the installation certification validity period". Is this worded correctly?	The intention of metering installation certification is that the lesser certification date of any metering component or the metering installation certification validity period should be used to calculate the expiry date. This wording will be examined during the submission review process.
29/07/10	I attended the EC workshop on the proposed Plan D changes on Monday morning from a Generator/asset owner's perspective. However the morning focus seemed	There is not too much that does affect a grid generator but I have listed the below for you, as a quick summary, and this should not be considered an extensive list. You should review the rules in detail yourself and draw your on conclusions for these.
	to be on retailers and distributors, and there was insufficient time to ask further questions.	<b>A.</b> From a grid generators perspective, the following applies currently and still applies within the new part $D/10$ .
	What impact do the proposed changes have on our generation meters?	<b>1.</b> The same issues apply about retaining certification of the metering installations as apply at the moment.
		<b>2.</b> The designs and documentation that you currently have for your metering installations need to be maintained up to date, and at a component and certification level.
		<b>3.</b> You need to contract an appropriately approved test house for all work on a metering installation.
		<b>4.</b> Error and loss compensation may be programmed into the meters or used in a back office process to generate submission information.
		<b>5.</b> Obligation for provision of accurate submission data, file formats etc do not change.
		<b>B.</b> From a grid generators perspective, the following also applies when the

Date	Question	Answer
		proposed rules become effective.
		<b>1.</b> Records must be maintained for a period of 48 months after a component is removed, or a metering installation decommissioned or modified.
		<b>2.</b> Local service meters may be certified according to the category that applies to the capacity of the local service supply itself.
		<b>3.</b> The metering category will be category 5 not 6, category 6 is merged with category 5.
		<b>4.</b> Where a metering installation is either new, replaced or modified, the design for the modification must be provided tot he grid owner, the grid owner may request changes to the design. Any meter installations that use summation, aggregation or subtraction of meter date will also need to be approved by the market administrator, and the market administrator may also require changes.
		<b>5.</b> Metering installation certification will be transitioned to the new part D/10 and the same certification expiry date will apply, metering installations will not need to be re-certified due to the transition itself.
		<b>6.</b> You will need to notify the reconciliation manager of your participant code, the NSP, and the certification expiry date for your metering installations. Whenever these attributes change, you need to re-notify the reconciliation manager.
		<b>7.</b> You will become the metering equipment provider, and will need to amend your participant registration to include metering equipment provider.
21/07/10	The insitu testing method for certifying Category 2 installations, which most if not all test houses have received approval for through a D3 4.3 departure, is not	The insitu testing method is termed "On site calibration" and is clause 12 of schedule 10.8 of part D/10, there is a departure for this from the rule 4.3 of code of practice D3 of schedule D1 of Part D provisions exercised by some approved test houses. t is not at this stage intended that those variations

Date	Question	Answer
	mentioned in the new Part 10. As this is now an excepted method but there is some confusion and inconsistency between test houses in how certification periods are applied for both components and installations, how do the new rules cover this?	<ul> <li>will transition to the proposed Code.</li> <li>The proposed rules operate slightly different to the current in-situ testing guidelines, in that all components of a metering installation used for the purpose of reconciliation must be certified, (Subclauses 8(5) and 9(3) of schedule 10.7 of part D/10) and the metering installation must be certified (clause 10.36 of part D/10).</li> <li>Obligations on test houses for on site calibration are contained in clause 6 of schedule 10.4 of part D/10 and also mentioned under recertification</li> </ul>
20/07/10	<ul> <li>Trader Maintenance process flow</li> <li>1. Can status be added/adjusted prior to MEP accepting or claiming events on the Registry?</li> <li>MEP Maintenance process flow</li> <li>2. Can a MEP claim the metering on the Registry where they are the nominated MEP, however have not</li> </ul>	<ul> <li>schedule 10.7 of part D/10.</li> <li>1. This situation should only occur with a new ICP. An ICP can be moved to active without an MEP populating information, however there must have been an MEP that has accepted the nomination using the acceptance notification to the registry.</li> <li>2. It is necessary for an MEP to accept the nomination before they become the MEP, they may reject the nomination. The acceptance notification sets permission in the registry for the new MEP to place information into the</li> </ul>
	<ul> <li>acknowledged the nomination? E.g. Is the MEP</li> <li>acknowledgement process tied into the initial claim</li> <li>process or an outside interface/function?</li> <li><b>3.</b> What is the expected migration method? Is the existing</li> <li>MEP field to be changed to nominated MEP?</li> <li>Acknowledgement required?</li> <li><b>4.</b> MEP timeframes are heavily reliant on the Trader</li> <li>updating the Registry. Since most Traders do not update</li> <li>the Registry until the metering is installed, can the</li> <li>timers/rules be adjusted accordingly?</li> </ul>	<ul> <li>permission in the registry for the new MEP to place information into the registry. From the time the MEP first enters registry metering information into the registry, the responsibility transfers from an existing MEP to the new MEP.</li> <li><b>3.</b> At the time a MEP is nominated by the trader within the registry, a notification will be generated to the distributor, trader, and if it is an existing MEP to the existing MEP. The visible MEP code in the registry will not change until the MEP accepts the nomination and first enters registry metering information in the registry.</li> <li><b>4.</b> It is necessary for a trader to accept ownership of an ICP before they</li> </ul>

Date	Question	Answer
	<b>5.</b> In addition to the above question, the Trader will essentially be populating the Registry with default or temporary new connection information as the metering configuration will not always be known prior to the physical metering installation taking place. Is there a proposed	can nominate an MEP. The latest requirements for update of registry metering information into the registry is five business days after a metering installation is certified – note that this could be pre-livening of the installation.
	process established to cater for initial Trader information to be populated in the Registry? It may well be that the Registry caters for this scenario (ICP stays at Ready status initially and only accepts the nominated MEP field) instead of Traders systems having to be changed dramatically. It is noted either way that the new	5. There may be an operational and timing issue for this that may require a change to registry functionality to allow the ICP to remain in the ready status for a period of time and allow the MEP to update information. Participant's suggestions on this and implications on their systems are requested.
<ul> <li>6. ICPs can switch between traders having an impact on the MEP (apart provisions arrangements). There may confirmation of Trader information (Profiles, Status &amp; Reconciliation information).</li> <li>6. What exactly is involved in the switching process where MEP's are involved? If there is no change in metering is no action required from Traders or MEP's?</li> <li>6. ICPs can switch between traders having an impact on the MEP (apart provisions arrangements). There may consider where a losing trader has part of the switching process where MEP's are involved? If there is no change in metering is no action required from Traders or MEP's?</li> </ul>	<b>6.</b> ICPs can switch between traders and also between distributors without having an impact on the MEP (apart from their invoicing and data provisions arrangements). There may be an issue that participants wish to consider where a losing trader has pre the switch commencing nominated a new MEP. The gaining trader would have no visibility of the proposed	
	change to an MEP. The proposed registry functionality does not include halting the MEP change process, however it could roll back the nomination for a new MEP.	
	7. Meter Installation level breakdown	where an ICP enters a trader switch process.
	<ul> <li>a) What is the expected behaviour? One meter per installation at Level 2 or multiple meters where a combined switchboard is under one ICP?</li> <li>b) Cortification information – Would it be more</li> </ul>	Participants are asked to consider if this functionality would be of benefit. <b>7(a)</b> There can be single or multiple meters within a metering installation, and multiple metering installations to an ICP. In effect, there is also nothing
	beneficial to have at individual component level certification information with overall automatic indicator at the higher meter installation level?	to preclude multiple metering installations within the same meter box provided that none of those metering installations are electrically interconnected.

Date	Question	Answer
	<ul> <li>c) Is relay or control device information expected to be populated down to level 3? Or is it anticipated that no channel level information should really exist?</li> </ul>	<b>7(b)</b> It was considered necessary to only have the meter installation expiry date as this is what is applicable to the settlement process. If you consider there is benefit in having component certification, please discuss in your submission.
	Switching functionality Changes	7(c) It is anticipated that channel level information would also apply to
	<b>8.</b> Is there a chance to remove NHH $\rightarrow$ HHR switches to reduce impact on Traders and MEP's in Registry along with any other metering change scenario that causes	control devices. Note that where a control device does not form part of the metering installation, it does not need to be recorded.
	issues for participants?	8. This is existing Rules functionality – if you consider this is something of
	<b>9.</b> NT files – Is it necessary to add submission type if the value is optional? Seems that the change to file format	benefit, you should suggest this as a rule change under the existing rule change process.
	isn't required as can be corrected after the switch	9. These are defined as optional within the registry functional specification.
	completes. This is dependent of course on decisions made	Participants should consider if this change is required.
du	during the switching process.	10(a) This was an O/M field in the current TT, and was left there for that
	<b>10.</b> TT files – Changes to HHR switching files	reason. Traders should consider in their submissions if this field should remain.
	<ul> <li>a) Is it necessary to have a nominated MEP in the TT file especially where no changes are required to existing arrangements?</li> </ul>	<b>10(b)</b> This was an O/M field in the current TT, and was left there for that reason. Traders should consider in their submissions if this field should
	b) Is it necessary to have a submission type in the	remain.
	HHR switching file?	<b>11.</b> It was not intended to have losing trader information validated at the
	<b>11.</b> Validations taking place between the Traders provided TN metering information and the MEP event information on the Registry. Possible for a MEP to cause switching	time of the issue of a TN. As traders may only hold traded meter registers within their systems, it was considered there could be unnecessary notifications issued.
	breaches with reduced timeframes being introduced.	Suggestions
	Courd these be warnings rather than childer errors?	<b>12.</b> MEPs are responsible for the accuracy of registry metering information.

Date	Question	Answer
	<ul> <li>c) Number of components</li> <li>d) Meter identifier</li> <li>e) Number of Registers/Channels – (Check relay)</li> </ul>	The population of the registry carried out in the implementation period, will require traders to validate that the registry metering information populated is correct prior to the go-live of the new registry.
	information) Suggestions:	The suggestion of a gaining trader having the ability to select download of all register information or only traded register information is functionality that all traders may find of benefit.
	Proposal to have TN file ignore losing Trader metering information and collect the Registry MEP information along with any unmetered load details.	Traders should include this in their submission if this is considered of benefit.
	<b>12.</b> We consider that this functionality should be optional and the Registry provider should facilitate the ability to choose whether or not the gaining Trader wishes to receive the losing Traders metering information or the Registry MEP asset event information. A parameter could be established under the supervisor switching notification settings to enable Traders to choose which option they wanted (MEP or Trader metering information). In the case of the Gaining Trader selecting the losing Traders metering information, the TN file would pass through the Registry without adjustment to the file content apart from where additional unmetered load information was	13. This is a relatively easy function to add, traders should include this in their submission if this is considered of benefit.
	We consider that although the MEP data may eventually become accurate through compliance and certification programmes, the data initially populated by MEP's may not be accurate and could result in downstream issues for	

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	the switching process and impact on customer billing. If the Trader decides they would like both streams of information a separate request can be made to the Registry to obtain the additional MEP information at the time of the switch to allow reconciliation of both the losing Traders and MEP's metering data.	
	Unmetered Information Flow	
	<b>13.</b> In addition to the above, we would recommend making the unmetered information within the TN file clearly identifiable. It would be beneficial to have the row marked differently to enable Traders to identify the unmetered information easily. One option would be to create a new record type (E.g. U – Unmetered   Existing record types are M – Meter, P – Premise etc.) so that participants could choose to process the event differently, trigger a work flow or ignore where existing processes are already in place. Another option could be for the Registry provider to implement a parameter under the supervisor switching notification giving the Trader the ability to decide whether they would like the unmetered information included in the TN file.	

Date	Question	Answer
15/07/10	Certification of load control #3 Schedule 10.7 26 (7) states that load control devices must have a dedicated power supply. In most installations the load control device takes supply from the load side of the meter. This ensures that the	<b>1.</b> Dedicated power supply means that the power supply is not shared with another component - i.e. it should be separately fused. The reason for that is that the failure of one components protective device will not affect the performance with another component. However given the above, and for control devices, this requirement may not be needed. Please include this in
	burden imposed by the load control device is measured by the meter.	<ul><li>your submission.</li><li>2. Please include this in your submission.</li></ul>
	If the meter fails, it is unlikely that the power supply to the load control device would also fail – since the copper bus that passes current through the meter is rated at 80A.	<b>3</b> . Interim certification for category 1 metering installations transitions to the proposed part D/10, and the same expiry date for interim certification of 1 April 2015 applies.
	In our view this is acceptable. If the meter has a disconnect switch which fails off, the load is completely	<b>4</b> . Certification granted under the current part D continues under the proposed part D/10 and the same expiry date applies.
disconnected from the network, so even if the supply to the load control device was separate to the meter, it would have no load to control.	<b>5.</b> The same requirements apply under the proposed part D/10 as do under the current part D. More specifically - meter installations that contain control devices where information is used for a reconciliation purpose	
	Please clarify	under part J must already be certified under the current part D rules - so
	1. What is meant by a dedicated power supply?	reconciliation purpose under part J it does not need to be certified. Refer to
<ul><li>2. Does a supply taken directly from the load side of the meter qualify as a dedicated supply?</li><li>Certification validity period</li></ul>	<ul><li>schedule 10.8 clause 5(1) of part D/10.</li><li>6. Meter installations that contain control devices where information is used</li></ul>	
	for a reconciliation purpose under part J must already be certified under the	
	<b>3</b> . Please clarify what Subpart 2 10-47 (4) means.	current part D rules - so they will not need re-certification. Where a control device is not used for a reconciliation purpose under part J it does not need
I read it to mean:	I read it to mean:	to be certified. Refer to schedule 10.8 clause 5(1) of part D/10.
	4. If a metering installation has been certified under Part	

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	D, that metering installation (excluding interim certification) and all its components will remain certified under Part 10 until the certification period of the metering installation (under Part D) expires.	Certification granted under the current part D will transition to the new part D/10.
	<ul> <li>5. If a metering installation that has been certified under Part D (excluding interim certification) includes load control devices which were not required to be certified under part D, will these be deemed to be certified under Part 10 until the certification period of the metering installation (under Part D) expires?</li> <li>6. In other words, when Part 10 comes into force, will we be required to visit each metering installation to certify each load control device?</li> </ul>	
14/07/10	<b>Certification of Load control #1</b> <b>1.</b> I understand from Subpart 2 - 10.47 (4) that a metering installation that has been certified under Part D will remain certified under Part 10. However Part D did not require certification of load control devices. Schedule 10.8-5 1(1) states that an MEP must ensure that a control device is certified by an ATH before the MEP uses the control device for any purpose under Part J. This implies that all load control devices will be required to be certified immediately.	<ol> <li>The use under part J is if the trader wishes to use the outcome of the control device within the reconciliation process. The MEP provides the installation, the trader is responsible for requirements within part J.</li> <li>If the certification covers the load control device - yes that is correct. Note that not all load control devices are required to be certified, only those that form part of the metering installation - this is an existing requirement has transferred to the new rules, refer to clause 5(1) of schedule 10.8. The current part D rules require that control devices used for register switching or controlled and the trader uses a controlled load profile within their settlement, must be included within the metering installation certification.</li> </ol>

Date	Question	Answer
	<ul><li>Please clarify:</li><li>2. When Part 10 comes into force, can load control devices that are on a metering installation certified under</li></ul>	<b>3</b> . There is a check box on the registry that will indicate the certification of the control device. This check box will indicate to retailers that they may use a controlled load profile on that metering installation.
	part D remain – assumed to be certified as part of the metering installation certification.	<b>4</b> . The method of transmission of load control signals is not included within the proposed part D/10. Where alternative or additional standards become available, these can be added by the Authority. Refer to clause 10.7(b) of
	registry	subpart 1.
	Certification of Load control #2	5(1) of schedule 10.8 only requires the control device to be certified where
	<ul><li>4. Schedule 10.8 5 states that all load control devices must be certified against the standards listed in table 4. The only standards listed are for ripple control and for time clocks.</li></ul>	it is used for any purpose under part J. That is, where the control device is used for register switching or controlled and the trader uses a controlled load profile within their settlement. Where a trader wishes to use either register switching or controlled load proofing and the registry indicates that
	There are many existing and emerging technologies that either don't have an IEC standard, or don't have a standard at all. Examples include: pilot wire, cyclo control, mesh radio.	the control device is not certified as part of the metering installation, the trader should ask the metering equipment provider to have the metering installation re-certified to include the control device, or use the residual profile for reconciliation under part J.
	<b>5</b> . Further, under Subpart 1 10.32, a MEP is required consult a distributor and trader on the integration of a	<b>6</b> . No, the term will apply to any device that will exert control and that control information is used for reconciliation purposes under part J.
	ripple receiver into the meter (we note the use of "ripple receiver" rather than "control device")	<b>7.</b> Where alternative or additional standards become available, these can be added by the Authority. Refer to clause 10.7(b) of subpart 1.
	Please clarify:	8. Data storage device means a device that electronically stores and
	<b>6</b> . Is the intent to restrict load control devices to either ripple control or time clock technology?	makes available information regardless if integrated into another component or is a stand alone device. We are not aware of specific standards, however 10.8 clause 6(d) requires the device to be tested by an

Date	Question	Answer
	<ul> <li>7. Is there a provision in the proposed Part 10 to cater for existing or emerging technologies where there is no current standard to certify against (I cant find one).</li> <li>Certification of data storage devices</li> </ul>	approved test laboratory for compliance with prescribed standards or defined requirements. Where a data storage device is integral with a meter, the meter standards approval and type testing may cover the data storage device.
	<ul> <li>Schedule 10.8 6 states that all data storage devices must be certified against the standards listed in table 4. There are no standards listed in table 4 for dataloggers.</li> <li>Data storage standards generally do not exist, and are highly unlikely to exist for devices in emerging AMI technologies, including radio-mesh collectors.</li> <li>Please clarify:</li> <li>8. What data storage device standards are intended to be listed in table 4?</li> <li>9. Is there a provision in the proposed part 10 to cater for</li> </ul>	<ul> <li>9. Data storage devices are required to type tested under schedule 10.8 clause 6(d). This requires the device to be tested by an approved test laboratory for compliance with prescribed standards or defined requirements - where standards are not available, defined requirements. Note that new or revised, or alternative standards that become available, can be added by the Authority. Refer to clause 10.7(b) of subpart 1.</li> <li>10. The trader must continue to trade the site under the requirements of part J, but would be in breach of the Code for trading non- compliant metering information.</li> <li>11. The MEP would be in breach of the Code for allowing an active metering installation to become non-compliant. This would be checked</li> </ul>
	existing or emerging technologies where there is no current standard to certify against (I can't find one)?	during the MEP audit, and the check would ensure that the registry certification was appropriately updated. Any breach of the Code would be passed to the Authorities Governance section.
	<ul> <li>Cancellation of Certification of a metering installation</li> <li>Please clarify</li> <li>If the certification of a metering installation is cancelled</li> <li>(under any reason outlined in schedule 10.7 16) what is</li> <li>the impact on the MEP and Trader?</li> <li>10. Can the trader remain trading on the site?</li> </ul>	<ul> <li>12. The requirement for a low level inspection every year has been removed, there is still the requirement to have only the one inspection, but instead of at 10 years has been placed at half way through the certification validity period for the installation.</li> <li>13. Is half way through the certification validity period for the installation.</li> <li>14. Table 1 of schedule 10.1 gives a period range.</li> </ul>
	11. Is the MEP in breach of the rules, and what is the	

Date	Question	Answer
	<ul> <li>consequence of that breach</li> <li>Inspection period of Cat 1 sites</li> <li>Please clarify</li> <li>12. Why has the inspection period been reduced from 10 years to 7.5 years</li> <li>13. What is the significance of 7.5 years?</li> <li>14. Is the intent to complete all inspections within 7.5 years of installation, or that the mean inspection period is 7.5 years? If the former, the inspection results would be skewed towards the early part of the certification period (i.e. less than 7.5 years) which may be a bad outcome (since meter faults are more likely to occur in the later part of the certification period).</li> <li>MEP consultation with a trader or Distributor prior to installation of a meter</li> <li>Under Subpart 1 10.32, an MEP must consult a distributor and trader on, required functionality.</li> <li>Please clarify</li> <li>15. What happens if the parties don't agree?</li> <li>16. What happens if the distributor (who may also be an Meter owner) wishes to specify a meter that complies with their own specification (e.g. for smart grid purposes) but the MEP does not agree.</li> </ul>	<ul> <li>15. There is a commercial incentive for participants to agree, as the provision of functionality will attract a lease fee. Refer to the revised wording within 10.32 where a disputes process has been included.</li> <li>16. In the case of a new ICP, or a change of MEP at an existing ICP, the MEP does not need to accept the nomination to be the MEP for an ICP, and should make its own decision on what equipment to use. Refer to rule 1.2 of schedule E3 of part E and clauses 10.22 and 10.23 of part D/10. In the case of a change of MEP at an existing ICP, the old MEP remains responsible until the new MEP accepts responsibility under part E. Clause 10.32 of part D/10 discusses functionality and not manufacture - the way requirements of the distributor and retailer are met is left to the MEP to decide. However there is nothing to preclude an MEP accepting a manufacture recommended by the distributor or retailer where all required functionality is met.</li> <li>17. 10.32 of part D/10 requires consultation, and does not give the power of veto for the manufacture of components to either the trader or the distributor.</li> <li>18. Meter box or other enclosure that are used to house metering components.</li> <li>19. Can be anyone.</li> <li>20. Any user of information from a metering installation.</li> </ul>

Date	Question	Answer
	<b>17</b> . What powers do distributors have to veto MEP's meters	
	Definitions	
	Please clarify what is meant by the following:	
	<b>18.</b> Schedule 10.7-30 – Enclosure (is this a meter box, or a meter casing)	
	19. Person	
	<b>20.</b> User	
12/07/10	<ol> <li>Rule 20 (1) (c), Schedule 10.7 - If test houses are able to or expected to calculate and apply non technical loss factors to a compensation factor then we believe that the industry will lose the transparency of reconciliation losses being published and maintained on the Electricity Commission Registry and the role of distributor audits in verifying that reconciliation losses are being correctly calculated. Can you please confirm if the intention of this rule is to allow technical losses to be calculated and treated as a compensation factor?</li> <li>Rule 20 (3) (b), Schedule 10.7 - We cannot find the defined term or attribute described as compensation factor within the registry functional specification. Can you please advise if this is an omission or error?</li> <li>Rule 31 (2) (b), Schedule 10.7 - Can you please</li> </ol>	<ol> <li>It is not intended that distribution loss factors are programmed as a compensation factor. Loss compensation refers to a compensation factor used when a meter is not located physically close to the point of connection. Refer to clause 10.33 of subpart 2 of part D/10</li> <li>The term used in the registry functional specification is "ratio compensation" this should be "compensation factor"</li> <li>There can be multiple users of metering installations; the intention is that this would apply to contracted users. Anyone without a contract should not be receiving information from a MEP, refer to clause 1(1) of schedule 10.6 of part D/10.</li> <li>The methodology will certainly support this, please include this within your submission.</li> <li>It is possible to do this; an alternative approach would be to either give a period of time for repair/replacement prior to metering installation</li> </ol>

Date	Question	Answer
	<ul> <li>confirm that it is the intention of this rule to allow non contracted users of metering data to be able to influence the replacement of meter components or otherwise?</li> <li>4. Definition of Metering Installation – The current definition of a metering installation allows for multiple meters to be aggregated under a single metering installation. Can you please advise if, from a functional perspective of representing data on the Electricity Registry, this term is amended so that only a single meter or metering point can be represented for each metering installation. For example:- an ICP with 3 TOU meters under a single metering installation records, 1 to 3 load control device records, 1 certification record. In addition there could be up to 24 channel records (3 meters x 8 channels). Alternatively if each meter was a separate metering installation this data would be more ordered and relevant.</li> <li>5. Control device certification - Load control device certification is only valid where a participant wishes to use the load control device for either profile or pricing purposes. If a participant chooses to submit using the RPS profile and only offers anytime pricing then the operation of compliance of the load control device should not impact the metering installation's overall certification status. Can you please advise whether the compliance of the load control device can be identified and monitored</li> </ul>	<ul> <li>certification cancellation. Please include this in your submission.</li> <li>6. It is possible to do this, please include this within your submission.</li> <li>7. It is not the intention, the same requirements should apply. Please include this within your submission.</li> <li>8. These will be updated when the final version of part D is completed.</li> </ul>

Date	Question	Answer
	separately so that the meter installation compliance is not affected if a load control device fails but market settlement is not affected.	
	<b>6</b> . Phase failure indicator registry field – given the potential of an unidentified phase failure to impact materially market settlement, can you please advise if a field can be added to the list of registry attributes to identify which meters / data storage devices can detect phase failure?	
	<b>7</b> . Rule 5, Schedule J2 – This rule in its current format excludes remote interrogation of AMI meters and also the collection of event lists from any data storage device when submitting meter data as NHH – can you this is the intention of this rule?	
	<b>8</b> . References to part D – A number of definitions and rules within Parts E and J still refer to Part D – given that this new Part 10 will replace Part D can you please advise why these rule references have not been updated to reflect Part 10?	
07/07/10	Process charts 1.One thing that has repeatedly come up is the ability to see process diagrams of major workflows such as: Part E1 Creation and management of ICP's Part E2 New ICP switch process	<ol> <li>We have some existing process flow diagrams that we will re-constitute and maybe use the layout you have indicated in yours.</li> <li>Part D/10 does not extend into the control signal, and stops at the capability and likelihood of the device to receive a signal. If a device is not operating, and the information is being used in the reconciliation process, there are large impacts to participants for that non-operation.</li> </ol>

Date	Question	Answer
	Part E3 New MEP switch process	3. Please feel free to provide a submission on this issue.
	The sequence of events following a removal of certification (i.e. MEP must undertake an investigation of a metering installation which starts at Part 10 - 10.7 16 and goes into Subpart 2 10.41	<b>4</b> . Please feel free to provide a submission on this issue.
	I have attempted to map out 3 of these processes (see attached), but it would be better if it came from the EC.	
	Certification of Load Control	
	We have been discussing how load control could be certified – in particular how the distributor responsibility loop could be closed.	
	Under Part 10 the MEP (or their ATH) is responsible for ensuring that there is a reliable signal on site. If there is not they must remove the device.	
	2. Our principle concern is that under part 10 the load control signal forms a critical part of the metering infrastructure, yet it is outside the control of the MEP. There appears to be nothing to stop a distributor from stopping investment in load control altogether if it does not suit their purposes at the time. Part 10 does not put requirements on the distributor to ensure a signal is available, yet is has (or can have) huge impacts on other participants who must remove certification, remove the load control device and change the customer tariff.	

Date	Question	Answer
	<ul> <li>3. Our thoughts to solve this are to put in responsibilities on distributors who own signalling equipment that are similar to MEP's. i.e. since load control forms a critical part of metering infrastructure, then the owners of signalling equipment should be responsible for ensuring that it remains compliant. They should indicate on the registry whether there a signal is available for use at each ICP, and be audited on this. Also similar to MEP's – owners of signalling equipment should be required to consult with users of the system prior to changing that system.</li> <li>4. My question is – does the EC have the ability to put such responsibilities on distributors?</li> </ul>	
02/07/10	Is there a word format available for Appendix 1?	Yes, this has now been published
30/06/10	Perhaps not surprisingly, the proposed new Part 10 is causing some debate as to just what the new arrangements are for nominating the MEP at an ICP. Please can you check whether the following interpretation is broadly correct?	<ul> <li>1. A distributor may not liven an ICP where there is no MEP, clause 10.31 of part D/10. Traders nominate MEPs and this requirement is carried over from the existing part E of the rule into the proposed rules. The process is as follows,</li> <li>a) In the case of a new ICP the trader nominates the MEP.</li> </ul>
	<b>1</b> . By 10.19(1) the trader at each ICP must ensure that there is an MEP; that doesn't mean they may chose an MEP or fire an existing one, simply that they may not trade on the ICP unless an MEP is in place.	b) The trader may choose to replace the MEP on an existing ICP. However, the MEP always has the right to decline the nomination, refer to rule 1.2 of schedule E3 of part E, and the existing MEP retains obligations until it is replaced, clause 10.22 of part D/10. So in the case of an existing

Date	Question	Answer
	<b>2</b> . By 10.20(a) at the date the rules take effect the existing meter owner at each ICP becomes the MEP.	ICP, the existing MEP remains responsible until another MEP is nominated by the trader and accepts the nomination.
	<b>3.</b> By 10.20(b) for each subsequent new ICP the initial trader must nominate an MEP.	However clause 10.32 of part D/10 requires the MEP to consult with the distributor and trader for functionality.
	<b>4.</b> Once an MEP is in place for any ICP then by 10.23 and 10.24 that MEP can only be displaced with their agreement.	<b>2</b> . The primary metering contact noted at the time of transition, within the registry, will transition to become the MEP. Note that the primary metering contact under the current rule 3.1.3 of schedule E1 of part E is nominated
	<b>5.</b> Since being an MEP gives a level of monopoly power over services at any given ICP, Schedule 10.6 protects other authorised users	by the trader. <b>3</b> . Yes, that is correct. Note that a distributor may not liven an ICP where there is no MEP clause 10.31(a)(ii).
	Two further questions:	4. Please refer to revised wording for clause 10.23. A MEP may only be
<b>6</b> . Presumably there is somewhere a clause to allow the EA to displace an MEP for cause, e.g. persistent poor performance? Where?	replaced where the trader re-nominates the MEP using the process described rule 3.1.3 of schedule E1 of part E. Re-nomination of the MEP within this registry field commences a process of change, refer to schedule	
	7. Where is the rule implementing the provision from the	with the distributor and trader for functionality.
AMI discussion that a trader may have a meter displaced for reasons of functionality or price? Or will that come in only after the AMI discussion is complete?	<b>5</b> . Schedule 10.6 sets out provisions for data access and other general operational requirements of MEPs. There are other clauses that protect users which includes Clause 10.32 of part D/10, and clause 31 of schedule 10.7 of part D/10	
		<b>6.</b> The Authority or any other participant can allege a rule breach against a MEP, but as there is no certification process for a MEP cannot remove certification, or order the replacement of a MEP. However a trader may renominate a MEP where there is an issue. Note that there is a mandatory

Date	Question	Answer
		audit process for MEPs refer to schedule 10.5 of part D/10. <b>7.</b> Replacement of any metering component is at the discretion of the MEP, and replacement of any MEP at an ICP is at the discretion of the trader. Any person may request a change to the functionality of a metering installation. Note that clause 31 of schedule 10.7 of part D/10 allows a MEP to replace a metering component with "Like for Like" or "Like for Better" despite any contract with any participant. So the request for an upgrade of a metering installation with the existing MEP does not require approval from other users of the metering installation unless the price charged to them is affected or the functionality to them is reduced. Note the provisions under this clause. The discussed displacement issue above will be within the AMI guidelines
29/06/10	<ol> <li>Clause 10.23: We assume this clause does not imply that the reconciliation participant has a "veto/approving" role for the change in metering equipment provider. Can this be confirmed?</li> <li>Clauses 10.23 and 10.24: Does the phrase "contracts with another person/metering equipment provider" imply that both parties have a choice to enter that relationship? Could the incumbent metering equipment provider prevent the new equipment metering provider taking over by refusing to contract with them?</li> <li>Clause 10.24: If a metering equipment provider is a party other than the consumer and the consumer wants to</li> </ol>	<ol> <li>Please refer to revised wording for clause 10.23. A MEP may only be replaced where the trader re-nominates the MEP using the process described rule 3.1.3 of schedule E1 of part E. Re-nomination of the MEP within this registry field commences a process of change, refer to schedule E3 of part E. Clause 10.32 of part D/10 requires the new MEP to consult with the distributor and trader for functionality but does not give the distributor the right of veto for a MEP.</li> <li>Please refer to revised wording for clause 10.23. The incumbent MEP could not prevent the change in MEP at an ICP. Note that replacement of any metering component is at the discretion of the incumbent MEP, and replacement of any MEP at an ICP is at the discretion of the trader. Any person may request a change to the functionality of a metering installation. Note that clause 31 of schedule 10.7 of part D/10 allows a MEP to replace</li> </ol>

Date	Question	Answer
	change the metering equipment provider is this permitted under the new rules? If so, what benefit is derived from the incumbent metering provider needing to contract with the incoming metering provider, if the incoming provider is appointed by the consumer?	a metering component with "Like for Like" or "Like for Better" despite any contract with any participant. So the request for an upgrade of a metering installation with the existing MEP does not require approval from other users of the metering installation unless the price charged to them is affected or the functionality to them is reduced. Note the provisions under this clause
	4. Clause 10.36: It is unclear how the metering equipment owner is protected from having to pay to obtain and maintain certification for metering components that are not owned by the metering equipment owner. Will the metering equipment owner have a means of either placing the obligation onto the metering component owner or recovering the costs of any upgrade from the metering component owner? If not, how will situations where a metering component owner refuses to make their own equipment compliant be handled?	3. The MEP is appointed by the trader in the same way that the primary metering contact is appointed by the trader under the current part D and E. A consumer cannot appoint the primary metering contact under the current rules but could ask the trader to use a primary metering contact of the consumers preference. This would remain a commercial issue between the consumer and the trader. Note that the trader may nominate a change in MEP at any time, so a trader that was not satisfied with the performance of a metering installation or the MEP could commence this change process regardless of the consumers preference - this is the same as occurs under the current Part D rules.
		<b>4</b> . The MEP is responsible for the certification of the metering installation, and the compliance of all of the components within the metering installation. If a metering component was no longer certified, or faulty that component could be replaced of any metering component is at the discretion of the incumbent MEP under the rules, and would we expect be covered under commercial agreements between the MEP and component owners. This is very similar to the current requirement for agreements of responsibility required under rule 1 of code of practice D3 of schedule D1 of part D