Electricity Fee Structures

November 2020

Draft Report and Determination

A draft report and determination on electricity fee structures to apply to Participant fees from 1 July 2021

Notice of second stage consultation – Electricity Fee Structures

NATIONAL ELECTRICITY RULES – RULE 8.9

Date of Notice: 25 November 2020

This notice informs all Registered Participants and interested parties (Consulted Persons) that AEMO is commencing the second stage of its consultation on Electricity Fee Structures for the National Electricity Market (NEM).

AEMO consults on its proposed fee structure for participant fees under clause 2.11 of the National Electricity Rules (Rules) and in accordance with the Rules consultation requirements detailed in rule 8.9 of the NER.

This document has effect only for the purposes set out in the Rules; and the Rules and the National Electricity Law (NEL) prevail over this document to the extent of any inconsistency.

This publication has been prepared by AEMO using information available at 30 November 2020.

Invitation to make submissions

AEMO invites written submissions on this Draft Report and Determination (Draft Report).

Please identify any parts of your submission that you wish to remain confidential, and explain why. AEMO may still publish that information if it does not consider it to be confidential, but will consult with you before doing so.

Consulted Persons should note that material identified as confidential may be given less weight in the decision-making process than material that is published.

Closing Date and Time

Submissions in response to this Notice of Second Stage of Rules Consultation should be sent by email to Kevin.Ly@aemo.com.au, to reach AEMO by 5.00pm (Melbourne time) on 4 February 2021.

All submissions must be forwarded in electronic format (both pdf and Word). Please send any queries about this consultation to the same email address.

Submissions received after the closing date and time will not be valid, and AEMO is not obliged to consider them. Any late submissions should explain the reason for lateness and the detriment to you if AEMO does not consider your submission.

Publication

All submissions will be published on AEMO's website, other than confidential submissions or confidential content.

Executive summary

The publication of this Draft Report and Determination (Draft Report) commences the second stage of the Rules consultation process conducted by AEMO on the structure of the Participant fees to apply from 1 July 2021 for AEMO's revenue requirements under the National Electricity Rules (NER) for:

- The National Electricity Market (NEM).
- Developing Retail Markets and administering Retail Competition – the current Full Retail Contestability (FRC) fee.
- The National Transmission Planner (NTP) functions.
- Major Reform Initiatives, including Five Minute Settlement (5MS) and Global Settlement (GS), and Distributed Energy Resources (DER) integration.
- The Energy Consumers Australia (ECA) fees recovered by AEMO from Participant fees.
- Registrations.
- NEM Participant Compensation Fund (PCF).
- Incremental service fees.

The current structure of Participant fees expires on 30 June 2021.

This review considers the structure to be applied to recover AEMO's budgeted revenue requirements, and not the actual amount charged, as the latter occurs in the annual budget and fee process.

Since the last fee determination in 2016, the market has been transforming rapidly to accommodate new technologies and new participants that are not charged in the current fee structure. This transformation has included a range of regulatory reform and operational changes needed to address the increasing complexities involved in planning and operating energy systems and markets. AEMO's responsibilities and functions have increased, and its scope and focus of interactions with registered participants has changed.

AEMO must develop a fee structure that recovers the budgeted revenue requirements for AEMO including the registered participants to be charged and appropriate metrics/pricing mechanisms, in a manner that is consistent (to the extent practicable) with the fee principles under the Rules and having regard to the National Electricity Objective (NEO).

Key matters raised in submissions

AEMO received 14 submissions to its Consultation Paper published on 18 August 2020[1]. The key matters for consultation, and the main themes from stakeholder submissions and meetings held, include:

- The term of the fee determination – two main options appeared from stakeholders, these being either a three-year fee period or a five-year fee period.
- Generator charging – the majority of stakeholders were aligned with reviewing the allocation of charges to generator classes, while others supported maintaining the existing allocation of charges.
- Market customer charging – the majority of stakeholders supported the existing charging mechanism of $/MWh, while others supported a change to per connection point (or $/NMI) charge or a combination of both variable and fixed rates.
- Charging network service providers (NSPs) – the majority of stakeholders did not support extending the core NEM fee recovery to NSPs.
- National Transmission Planning (NTP) fee – two stakeholders responded to this issue and both supported continuation of a tariff based on energy consumed as per the current transitional arrangement.

[1] The Consultation Paper available on AEMO's website at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-market-participant-fee-structure-review/final-aemo-electricity-fee-structure-consultation-paper_aug-2020.pdf?la=en

- Electricity Retail Markets fee – the majority of stakeholders supported changing the current fee metric from a per connection point ($/NMI) basis to a $/MWh basis.
- Recovery of major transformational initiatives:
  - Five Minute Settlement (5MS) program: the majority of stakeholders preferred recovery of 5MS from all existing registered participants via the Core NEM fee as opposed to recovery from market customers only;
  - Distributed Energy Resource (DER) integration: the majority of stakeholders supported recovery on a beneficiary-pays basis (i.e. reflective of involvement), with some stakeholders preferring recovery across all existing participants, and a smaller portion supporting recovery from market customers only via the Core NEM fee;
  - Energy Consumer Data Right (CDR): Majority of stakeholders supported recovery from all existing participants, followed by preference for a beneficiary-pays approach, and one stakeholder supported recovery from market customers only;
  - Digital refresh: two submissions provided feedback on the recovery of the digital program with both stakeholders supporting recovery from all existing participants allocated via the Core NEM fee.
  - Regulatory compliance programs: Two submissions responded to this issue with both stakeholders in favour of recovery from the Core NEM fee across all existing participants.
- Energy Consumers Australia (ECA), NEM Participant Compensation Fund (PCF), Registration fees and Incremental service fees – the current approach for each of these fee categories was largely supported by all stakeholders.

Appendix D provides a summary of AEMO's response to stakeholder submissions.

AEMO's draft determinations on the above matters

After consideration of stakeholder submissions and stakeholder meetings, and consistent with the fee structure principles and having regard to National Electricity Objective (NEO), AEMO's Draft Report, for stakeholder feedback, proposes the following approaches for each of the main issues identified above. The full draft fee structure has been outlined in Appendix B.

- The term of the fee structure determination – AEMO proposes a 5-year fee structure determination period with a transition period of two years to allow for the more fundamental changes proposed in determination to take effect (explained further in sections 3.2 and 4). Although not a consideration in determining the five-year term (with a two-year transition period), AEMO notes that our governance and operating model review is occurring in 2021. This will include consideration of whether the current approach to cost recovery using participant fees remains appropriate for the future and this will undergo consultation with participants and may ultimately lead to changes in the regulatory regime to reflect any changes and impact the fee structure determined under clause 2.11.
- Charging Generators – AEMO proposes to:
  - Maintain the existing percentage attribution of core NEM allocated fees to Generators, MNSP, SGAs and MASPs/DRSPs for the first two years of the next fee structure period, that is the transition period; then
  - Increase the percentage attribution of core NEM allocated costs to Generators, MNSP, SGAs and MASPs/DRSPs from 1 July 2023, reflecting an increased level of involvement with the revenue requirements for AEMO's core NEM activities; and
  - Maintain the existing charging approach for Generators, MNSP, SGAs and MASPs/DRSPs based on an average share of output (MWh) and capacity (MW).
- Market customer tariff – AEMO proposes to:
  - Maintain the existing percentage attribution of the core NEM allocated costs to Market Customers for the two-year transition period, that is from 1 July 2021 to 30 June 2023. For the transition period, the current method of a rate per MWh for a financial year would be used;

  - From 1 July 2023, the percentage attribution of the core NEM allocated costs to Market Customers will reduce;
  - From 1 July 2023, amend the Market Customer tariff to a combination of $/MWh and $/NMI on a 50/50 allocation so that there is some consideration of demand elasticity to a volume tariff, reflection of the differences between small and large customers, and to reflect the fact the bulk of AEMO's costs are fixed; and
  - From 1 July 2021 for the duration of the fee structure period, to maintain the existing attribution of the unallocated costs to Market Customers.
- Charging Network Service Providers (NSPs) – AEMO proposes to:
  - Maintain the existing allocation of core NEM fees to Generators and Market Customers for the first two years of the next fee period, that is the transition period; then
  - Introduce a separate allocation of the core NEM function costs to TNSPs and to DNSPs from 1 July 2023, to reflect the extent of their involvement with AEMO' core NEM activities, on the basis of energy consumed.
- NTP fee – AEMO proposes that TNSPs continue to be charged NTP fees based on their respective jurisdictions' consumption for the latest completed financial year and equal monthly invoicing.
- Electricity Retail Markets fee – AEMO proposes to maintain the status quo of recovering fees from Market Customers (excluding Metering Coordinators) on a per connection point ($/NMI) basis consistent with the simplicity and non-discrimination fee principles.
- For transformational initiatives, AEMO proposes the following:
  - 5MS – a separate 5MS fee in the fee structure, split between general legacy upgrades and new 5MS-specific upgrade activities, allocated directly to relevant participants reflective of involvement where reasonably practicable, or using the core NEM percentage allocations;
  - DER integration – a separate fee in the fee structure (excluding the Energy Consumer Data Right), allocated directly to relevant participants reflective of involvement and/or benefit but with a separate allocation to Wholesale Demand Response (WDR) Mechanism participants, that is, Demand Resource Service Providers (DRSPs) following commencement of the WDR program, based on a fixed allocation to recover a percentage of the establishment cost of the WDR program.
  - Energy CDR – to defer determination on the basis of current uncertainties, however, AEMO notes potential for this initiative to become a declared NEM project and subsequently incorporated into the fee structure upon commencement; and
  - Digital and Regulatory Compliance programs – to recover the costs of the digital and the regulatory compliance capital programs from registered participants through the core NEM cost allocation.
- ECA, NEM PCF, Registrations and Incremental service fees – AEMO proposes to maintain the status quo, as per the current fee structure.

Contents

1. Stakeholder Consultation Process

As required by clause 2.11 of the NER, AEMO is consulting on Electricity Participant Fees in accordance with the Rules consultation process in rule 8.9.

AEMO's indicative timeline for this consultation is outlined below. Future dates may be adjusted depending on the number and complexity of issues raised in submissions.

Deliverable	Indicative Date
Notice of first stage consultation published	Tuesday 18 August 2020
Frist stage submissions closed	Wednesday 23 September 2020
Draft Report & Notice of second stage consultation published	Monday 30 November 2020
Submissions due on Draft Report	By Thursday 4 February 2021[2]
Final Report published	By Thursday 18 March 2021
Last date to publish the Final Report	Wednesday 31 March 2021

The publication of this Draft Report marks the commencement of the second stage of consultation.

[2] This date has changed since publication of the Consultation Paper to allow more time for submissions due to the Christmas and New Year period.

2. Background

2.1 NER requirements

AEMO consults on its proposed fee structure for Participant fees in accordance with clause 2.11 of the NER. Under the Rules, AEMO only has the power to recover market fees from registered participants.

In determining the structure of participant fees, AEMO must have regard to the NEO. In addition, the structure of participant fees must, to the extent practicable, be consistent with the following principles, referred to in this document as the Fee Structure Principles and set out in detail in Appendix A, which are stipulated in the NEL and the NER:

- The structure of Participant fees should be simple.
- The components of Participant fees charged to each registered participant should be reflective of the extent to which AEMO's budgeted revenue requirements involve that registered participant.
- Participant fees should not unreasonably discriminate against a category or categories of registered participants.
- Fees and charges are to be determined on a non-profit basis that provides for full cost recovery.
- The structure of the Participant fees should provide for the recovery of AEMO's budgeted revenue requirements on a specified basis.

The operation of clause 2.11.1 also needs to be understood in the context of its surrounding provisions which deal with budgets and the payment of Participant fees (which are consulted on separately to this consultation and process):

- Under clause 2.11.3, AEMO is required to prepare and publish its budgeted revenue requirements.
- That budget must take into account and identify revenue requirements for the matters set out in clause 2.11.3(b).
- Some, but not all of these matters are referred to in the components of Participant fees specified in section 2.11.1(c).
- However, AEMO may adopt 'components' of Participant fees which are different to or more than those set out in clause 2.11.1(c).
- Section 2.11.1(b)(2) of the NER provides that Participant fees should recover the budgeted revenue requirements for AEMO determined under clause 2.11.3.
- Under section 2.11.2, AEMO may charge Registered Participants the relevant component of Participants fees in accordance with the structure of Participant fees.

Consequently, the scheme of clauses 2.11.1 to 2.11.3 of the NER is:

- To require AEMO to determine the structure of Participant fees according to certain rules;
- To require AEMO to determine AEMO's budgeted revenue requirements according to certain rules; and
- To empower AEMO to recover the budgeted revenue requirements through charging registered participants in accordance with the structure of Participant fees.

2.2 Context for this consultation

The current structure of Participant fees in AEMO's electricity markets commenced on 1 July 2016 for a duration of five years, ending 30 June 2021. The Final Report of the Structure of Participant Fees in AEMO's Electricity Markets was published on AEMO's website[3] on 17 March 2016.

Since the commencement of the current structure, there have been a range of changes which have increased NEM forecasting complexity and regulatory reporting requirements that have affected AEMO's planning and operational activities, in particular:

- Rapid increase in variable renewable and distributed resources;
- Retirement of aging thermal resources;
- Improvements in and use of data; and
- Changes in the behaviour of consumer consumption.

The above changes have required AEMO to increase efforts to forecast, model and operate the power system accordingly.

Additionally, to accommodate the energy transformation occurring and expected to accelerate, the volume of rule changes in the NEM has tripled in the past three years, the majority of which directly impact AEMO. This has led, and will continue to lead, to an increase in AEMO's obligations related to:

- System planning, i.e. the introduction of the Integrated System Plan (ISP);
- Cyber security protections;
- Complex system modelling;
- Connections analysis and commissioning;
- Management of demand response programs;
- Market re-design considerations;
- Market and operations consultations; and
- Compliance reporting.

Further, there are new and expected participant categories, which need to be considered when reviewing the fee allocation so that the structure of fees is consistent with the NER.

Aside from the above, AEMO's existing information architecture was no longer capable of keeping up with both data requirements and speed required to effectively meet the needs of the NEM, and we are now in the second year of a five-year uplift program on AEMO's aging systems.

For the purpose of providing clarity, this fee structure consultation is being conducted in parallel with other consultations including:

- Renewing AEMO's engagement model, which is seeking to deliver a material shift in the level of transparency for market participants, consumers, and other stakeholders regarding AEMO's understanding and communication of current and emerging challenges, as well as a more two-way, collaborative experience for stakeholders in defining problems and identifying solutions;
- Reviewing AEMO's governance and operating models, including consideration of the system operator scope, legal structure, funding and regulatory models used in other jurisdictions as a result of changes in the industry including a major increase in both market obligations and operational complexity. The discussions on a new operating model and any outcomes from those discussions will not form part of matters considered in the consultation on the electricity fee structure; and
- The Gas fee structure consultation.

[3] Information on the final report, including other consultation documents and submissions, available on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-markets-structure-of-participant-fees

2.3 First stage consultation

AEMO issued a Notice of First Stage Consultation on 18 August 2020.

Due to regulatory changes to accommodate the transforming energy market, the objective of the Consultation Paper was to provide stakeholders with the opportunity to have input into the development of the structure of Participant fees to apply from 1 July 2021, noting that the consultation does not apply to the actual amount charged for each fee[4].

AEMO received 14 written submissions in the first stage of consultation. AEMO also held video conferences with a number of stakeholders (individually) who requested them, namely:

- AEC – 10 September 2020;
- EUAA – 28 September 2020;
- Red/Lumo Energy – 2 October 2020;
- Energy Australia – 6 October 2020;
- ENA – 9 October 2020;
- Mondo – 16 October 2020; and
- AGL – 26 October 2020.

Copies of all written submissions have been published on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review.

[4] The latter is to be determined on an annual basis, via the AEMO budgeting process.

3. Summary of Material Issues

3.1 Summary of key consultation issues

The table below provides an overview of the main issues to be addressed in relation to the key matters under consultation. It also highlights stakeholder views on the consultation matter.

Table 1 – Summary of key issues from the Consultation Paper

Consultation matter	Summary of the key issues
Term of the fee structure	• Determining the term requires a balance to be struck between providing fee certainty for a longer period of time with flexibility to change the participant fee structure as circumstances change, particularly given the energy transition and extent of reform on the horizon. • There was support by different stakeholders for both a 3-year term and 5-year term.
Core NEM generator charges	• AEMO is expected to experience greater challenges with modelling, controlling and operating the power system due to the increase in the number of non-visible / non-dispatchable generation. Currently there is no division in the fee structure between market generators that are Scheduled, Semi-scheduled and Non-scheduled, meaning they pay fees on an identical basis. • A noticeable trend in the NEM is the segmentation of services from providers. The NEM has historically been "heavy baseload" from investments in coal fired power stations. These stations have typically provided a number of services, such as energy, FCAS and sometimes SRAS, and have also provided a number of synchronous services such as inertia, fault contribution and dynamic, voltage control as a by-product of producing energy. • Going forward, new non-energy revenue streams and non-energy players (who are not yet subject to charging) may develop, e.g. Market Ancillary Service Providers (MASPs) have entered the FCAS market following implementation of the Ancillary Service Unbundling Rule and the DRSPs associated with the Wholesale Demand Response mechanism. • The majority of stakeholders supported reviewing the current Generator / MNSP allocation to consider other generator classes.
Market customer tariff	• Market Customers are allocated the greatest proportion of the budgeted costs through directly allocated and unallocated costs. • The existing arrangement is to charge the core NEM allocated and unallocated costs on a \$/MWh basis, and FRC costs on a \$/NMI basis. Under the current approach for the core NEM allocated and unallocated costs, the net metering arrangements means that NMIs with solar PV are bearing a lower proportion of the relevant costs than NMIs without solar PV. Going forward, with the increase in number of solar PV and DER, this is unlikely to be consistent with the non-discrimination principle and NEO. • There were a range of stakeholder views on the market customer tariff either supporting the current \$/MWh approach, or changing to an approach that accounts for PV and DER at the connection point. • AEMO therefore considered whether a "variable" \$/MWh, "fixed" \$/NMI tariff, "gross import and export" \$/MWh, or "combination" \$/MWh+\$/NMI approach is more consistent with the fee structure principles and NEO.

Charging NSPs	• Currently TNSPs and DNSPs are not allocated any of the core NEM function fees. • As the NEM transitions towards increased DER and Variable Renewable Energy (VRE), greater complexities are arising with operational, planning and forecasting systems, requiring greater levels of involvement with NSPs. As such, more NEM costs are attributed to NSPs, and the question arises as to whether the reflective of involvement principles means that a share of the core NEM fees should be allocated to NSPs. • There are uncertain administrative arrangements, timing and transitional issues associated with charging NSP Participant fees that may need to be considered. • On balance, stakeholder submissions did not support charging NSPs participant fees, however, these submissions were made without the context of the cost allocation survey results which show significant involvement with NSPs.
NTP fee	• With the move to an actionable Integrated System Plan (ISP), a policy decision was made that the TNSPs pay NTP fees and this is included in the rules. • The services provided by this function are undertaken for TNSPs directly, rather than Market Customers. • Discussions have been held with the TNSPs following the introduction of those rule changes, and the TNSPs have accepted that charges be based on a historical MWh basis. • No reasons to change this approach have been identified through submissions received to the Consultation Paper.
Recovery of transformational 5MS and DER integration programs	• Key capital programs, including 5MS and DER integration, are not currently included within the fee structure. • These are significant capital transformational programs, which impact or interact with a range of participant categories. • 5MS has required replacement of legacy NEM systems (i.e. not only for the 5MS program) as well as 5MS specific upgrades, therefore appropriate cost allocation should be considered. • The majority of stakeholders supported recovery of the 5MS program from all existing participants. • For the DER integration program, the majority of stakeholders were supportive of recovering costs from participants reflective of their involvement in, or who benefit directly from, the program. • There are still a range of 'unknowns' in relation to the Energy Consumer Data Right (CDR) program, therefore a determination on how this program will be recovered is not feasible at this time. It may be possible for the CDR to be considered as a 'declared NEM project' under the Rules once further details of CDR are known. • The majority of stakeholders supported recovering this program across all existing participants.
Digital and Regulatory Compliance programs	• These are enabling programs to allow AEMO to perform its functions more efficiently. • AEMO considers that these programs are business as usual initiatives and hence the cost recovery is through the core NEM allocation. • The stakeholders that responded to this issue supported allocation through the NEM fee with recovery from all existing participants; and use of the declared NEM project mechanism for future large regulatory initiatives.

3.2 Core NEM function cost allocation

In order to have a basis on which to allocate AEMO's budgeted revenue requirements in relation to the NEM, it is necessary to understand AEMO's activities and outputs and the costs attributed to them. That is, the services and functions provided by AEMO to participants.

AEMO has used its 2020/2021 budget for its core NEM function as the basis for this cost attribution analysis. This budget provides the most up-to-date information AEMO has available for the purposes of this Draft Determination. Although AEMO's annual costs will vary over the duration of the new structure, the 2020/21 budget provides a robust basis for notionally dividing AEMO's annual budgeted revenue requirements in relation to the NEM between AEMO's outputs during the period covered by the new structure.

The first step in the analysis of NEM costs was to identify those costs deemed to be direct, attributable costs to key NEM outputs and those costs that are deemed to be indirect costs that are allocated to the NEM function. Based on the 2020/21 budget, approximately 70% of NEM costs are deemed to be direct, attributable costs and approximately 30% of NEM costs are deemed to be indirect, non-attributable costs.

The second step in the analysis of NEM costs was to identify the key broad outputs of AEMO's activities in relation to AEMO's function. AEMO has identified a number of activities that it undertakes to support this function, which can be categorised into 10 broad outputs as follows:

- Power System Security
- Power system reliability
- Market operation
- Wholesale Metering and Settlements
- Prudential supervision
- Market Development
- Information dissemination including stakeholder engagement and consultation
- Retail Markets
- Registration[5]
- DER integration[6].

The next step in analysing the NEM costs was to allocate the NEM direct costs to each of the separate outputs identified above by using a survey. AEMO Senior Managers, 23 in total, were surveyed and requested to allocate their Division's costs against each of the key outputs identified above on the basis of time of interaction and involvement with specific participant classes. Senior Managers were provided with a detailed list of activities that were developed to represent each of the key outputs. The results of the survey were used to form the basis of the allocation of the NEM direct, attributable costs to the key outputs. Results were also verified with the relevant Senior Manager to explain differences noted from the previous determination.

Results of the cost allocation survey indicated the following key differences to the current NEM allocation:

- AEMO's activities involve other generator participant categories including Small Generator Aggregators (SGAs) and Market Ancillary Service Providers (MASPs)/Demand Response Service Providers (DRSPs).
- An increase in allocation to the Generators reflecting their increased involvement with AEMO's functions.
- There was a material level of allocation to TNSPs reflecting the increase of their involvement with AEMO's operational activities.
- A small allocation to DNSPs reflecting their involvement with AEMO's operational activities.
- The Market Customer allocation was therefore less than the current NEM allocation.

As outlined in section 2.1, clause 2.11.1(b)(2) of the NER, all of AEMO's budgeted revenue requirements must be recovered through Participant fees. In addition, AEMO must have regard to the NEO, and the structure of participant fees must, to the extent practicable, be consistent with the Fee Structure Principles. It should be noted that the Rules do not expressly indicate that one fee structure principle should have greater weight than the others. In application, it will not always be practicable for AEMO to satisfy all of the principles or to

[5] This relates to activities that AEMO teams perform to support the registration process that are not captured in the Registration fees section of the fee structure.

[6] This relates to activities that AEMO teams perform related to DER integration that are not captured in the DER Integration capital program, which AEMO proposes to be a separate fee in the fee structure.

an equal degree. Therefore, meeting the Rules requirements typically requires a trade-off between the principles, and AEMO's objective is to strike between the principles wherever possible.

As a result, applying the NER requirements, and in order to reflect AEMO's cost allocation survey, it was determined that the existing core NEM fee allocation should be amended as shown in Figure 1, the details of which are explained in section 4.

However, as this change represents a significant shift from status quo for a number of participants, particularly TNSPs and DNSPs who will likely require transitional arrangements to be put in place to allow them to recoup Participant Fees costs, a two-year transition period is proposed. The two-year transition would mean that for the first two years, from 1 July 2021, the current allocations of core NEM fees will apply to:

- Generators, MNSP, SGAs and MASPs/DRSPs participant categories, that is 46%; and
- Market Customers, that is 54%.

Figure 2 shows the above allocation.

When assessed against the NER principles and NEO, AEMO is of the view a transition period would:

- Still be relatively simple as the transitional structure remains generally the same as the existing structure, apart from the inclusion of separate 5MS and DER Integration functions;
- On the whole, reflect the level that registered participants are involved in AEMO's core NEM activities as these participant categories continue to remain relevant;
- Not unreasonably discriminate against any participant class, rather it allows consideration of the implementation requirements of the proposed changes;
- Continue to allow AEMO to recover its budgeted revenue requirements in a similar manner to the previous determination; and
- Continue to have regard to the NEO by ensuring implementation of the changes can be progressed effectively and efficiently in the longer-term interests of consumers.

The attribution of allocated costs and unallocated costs will be finalised for the Final Report. For this Draft Report the percentages for allocated and unallocated costs are indicative and are shown as approximately 70% and 30% respectively. Following the transition period, from 1 July 2023, the allocation of core NEM fees will be amended (as per Figure 1) to reflect the change in the level of involvement of participants in the following manner:

- Generators, MNSP, SGAs and MASPs/DRSPs to be allocated approximately 56%;
- Market Customers to be allocated approximately 23%;
- TNSPs to be allocated approximately 18%;
- DNSPs to be allocated approximately 3%.

These percentages will be finalised for the Final Report.

Figure 1 – Proposed approximate allocation for the core NEM function Allocated Costs to apply from 1 July 2023

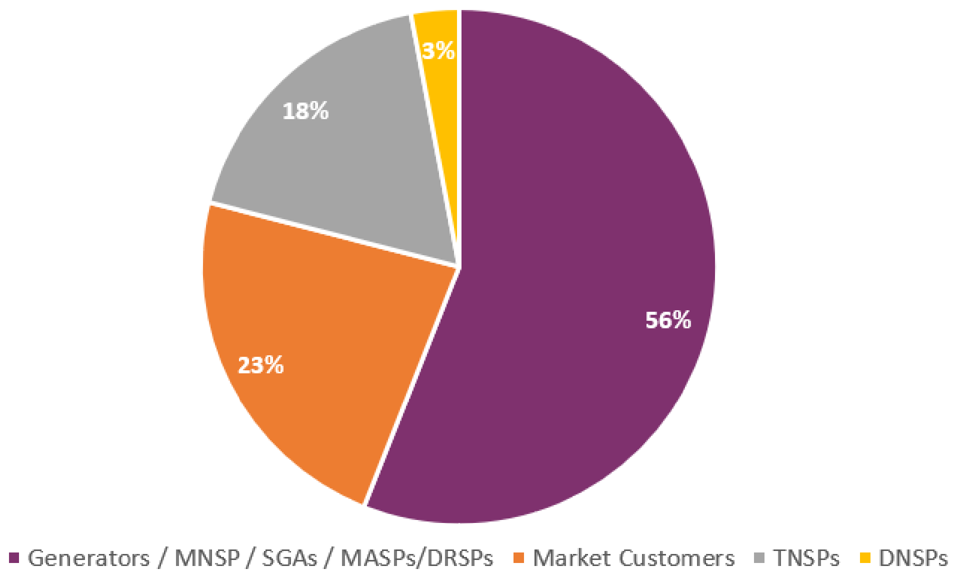
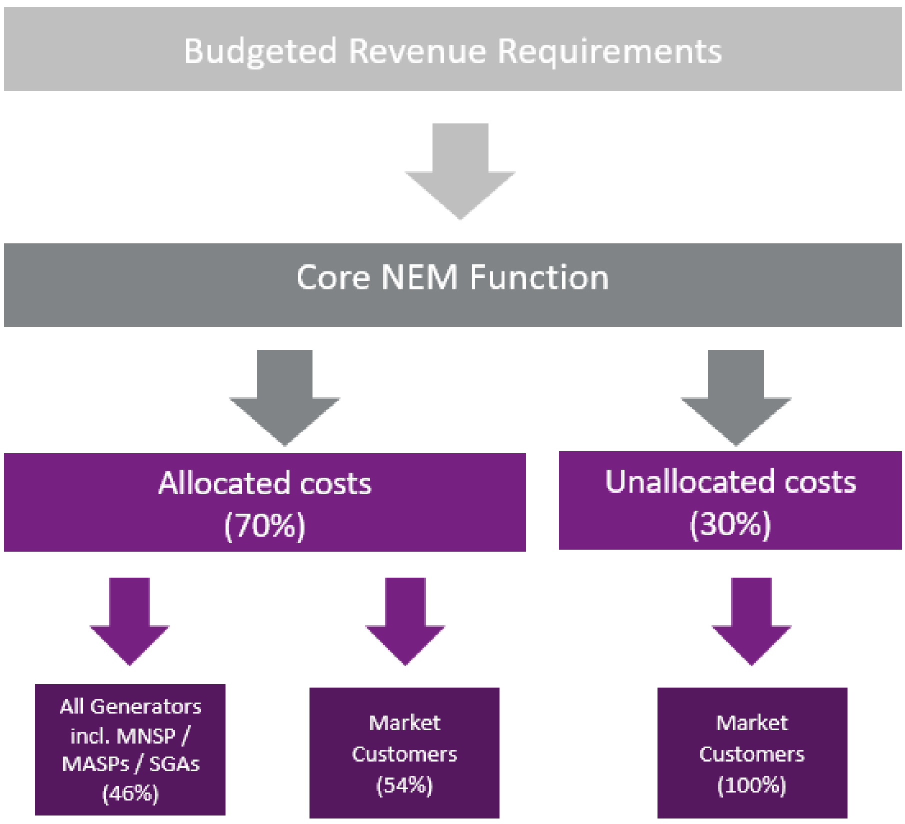


Figure 2 – Allocation for the core NEM function fee to apply during the transition period



4. Discussion of Material Issues

This section discusses the issues outlined in section 3 in further detail; highlights the options considered to address those issues incorporating stakeholder feedback and an assessment against the NEO and the fee structure principles; and AEMO's draft determination on each matter.

The principles assessment key is as follows:

(green)	Increases consistency with the principle
(red)	Decreases consistency with the principle
(grey)	Not relevant / neutral / minimal change

4.1 Term of the fee determination

4.1.1 Issues summary and stakeholder submissions

Since the 2006 fees structure determination, the term of AEMO fees structure has been a five-year fee term. Having a structure that applies over a longer period provides certainty and predictability of the structure of fees for participants and AEMO, however this needs to be balanced against having the flexibility to change the Participant fee structure as circumstances change, particularly given the energy transition and extent of reform on the horizon.

There were ten submissions that responded to this issue – a summary of their views is provided below.

Table 2 – Summary of stakeholder views on term of the fee structure

Option	Number of stakeholder responses	General comments
Shorter fee term (e.g. 2 or 3-years)	4	• Aligns with introduction of the WDR mechanism Will allow fees to be allocated in a manner that aligns with the NEM's rapid pace of change
Longer fee term (e.g. 4 or 5-years)	6	• Creates more certainty than a shorter fee period • Aligns with the P2025 process which may introduce new participant categories

4.1.2 AEMO's assessment

AEMO has considered stakeholder comments and assessed each of the options in Table 2 against the NEO and the NER principles applicable for determining the electricity fee structures.

Table 3 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Status quo (5-year term)	Simplicity	Pros • Provides more certainty to participants • Aligns with major reform work in progress including the ESB's P2025 • Allows sufficient time for transitional arrangements to be put in place
	Reflective of involvement	

	Not unreasonably discriminate	• Fee structure could be changed during the term if required as part of a Rule change, and/or a Declared NEM Project under the NER Cons • Would need to use the Declared NEM Project process to separately recover costs of major projects during the term • Fee structure may be less consistent with some fee structure principles by the end of the term
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	
Reduced term (3-year term)	Simplicity	Pros • Provides flexibility for market and regulatory changes, that introduce new participant categories, to be factored into a revised fee structure • Does not lock in a structure that may be become less consistent with some fee structure principles over a longer-term Cons • Does not provide as much certainty as a longer fee term
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	

4.1.3 AEMO's draft proposal

AEMO proposes a five-year fee term, with a two-year transition period. This has been proposed for the following reasons:

- A five-year fee term will provide participants with greater certainty over costs, as well as providing AEMO with more certainty regarding costs to be recovered from over a longer period.
- The five-year fee term (with a two-year transition period) aligns better with the NER principles, particularly the involvement principle, than the three-year or five-year (with no transition period) option by providing more certainty but allowing for an appropriate transition.
- The transition period will allow NSPs time to seek to make arrangements to recoup Participant Fees, particularly as NSPs commence their next regulatory control period at different times.
- The transition period will allow Market Customers to make any necessary changes to their systems and processes to account for proposed changes to the Market Customer tariff.

AEMO has considered other fee structures for comparison purposes, in particular the Gas Fee Structure, and AEMO notes that the draft proposal of the Gas Fee Structure term differs from our proposal for the Electricity Fee Structure. For the reasons above we believe it is reasonable that the two terms do not need to be aligned.

Although not a consideration in determining the five-year term (with a two-year transition period), AEMO notes that our governance and operating model review is occurring in 2021. This will include consideration of whether the current approach to cost recovery using participant fees remains appropriate for the future. This will undergo consultation with participants and may ultimately lead to changes in the regulatory regime to reflect any changes and impact the fee structure determined under clause 2.11.

4.2 Generator charging

4.2.1 Issues summary and submissions

Scheduled, Semi-scheduled and Non-scheduled generators currently pay fees on an identical basis as there is no division between those market generators in the fee structure. However, since the last fee structure determination there has been (and will continue to be) a significant increase in the number of Semi-scheduled and Non-scheduled generators, and AEMO is expected to experience greater challenges with modelling, controlling and operating the power system, resulting in greater involvement of those participants with AEMO's budgeted revenue requirements.

Additionally, Non-market scheduled generators currently pay less than Market generators, and Non-market non-scheduled generators do not pay anything due to the structure which divides the current Generator/MNSP costs as follows:

- Two-thirds of the Generators and MNSPs costs will be apportioned to all Generators (except Non-Market Non-Scheduled Generators) and MNSPs;
- One-third of the Generators and MNSPs costs will be apportioned only to Market generators and MNSPs.

No Generators and MNSPs costs will be apportioned to Non-Market Non-Scheduled Generators

This creates an unnecessary complexity to the attribution of generator charges, particularly as there are no Non-market scheduled or Non-market semi-scheduled generators registered in the NEM.

Further, the existing structure fails to adequately capture participants other than scheduled generators, e.g. MASPs, SGAs, Semi-scheduled generators. Additionally., new participants like DRSPs will emerge as the WDR mechanism becomes effective from October 2021[7].

There were seven submissions that responded to this issue – a summary of their views is provided below.

Table 4 – Summary of stakeholder views on generator charging

Option	Number of stakeholder responses	General comments
Maintain existing allocation of charges	2	• Caution needs to be taken with any changes that materially adds complexity to the fees charged • Further analysis is required to understand whether alternative metrics would facilitate more equitable allocation of costs
Review existing allocation of charges	5	• The existing structure fails to adequately capture participants other than Scheduled generators, e.g. MASPs, SGAs, Semi-scheduled generators • The distinction between different generator categories to reflect Non-market and Non-scheduled generators' reduced involvement in AEMO's functions is no longer meaningful • It could be appropriate for Semi-scheduled generators to pay slightly more than Scheduled generators due to their increased involvement in AEMO activities • While VRE generation is an increasing proportion of the generation basis on a MW basis, it is also an increasing proportion on a MWh basis, therefore continuation of the 50% energy 50% capacity approach may be appropriate

[7] It is expected MASPs would participate in the WDR under a new registration category called Demand Response Service Providers (DRSP)

4.2.2 AEMO's assessment

AEMO's cost allocation survey identified that there has been an increased level of involvement from the Generator participant category since the last fee determination. With the increase in variable renewable energy (VRE) generation expected in the coming years[8], it is likely that the level of involvement from this generator class will account for a higher proportion of AEMO's revenue requirements for core NEM activities (compared with other generators) as a result of increased operational and planning complexities associated with the impact of their penetration levels in the NEM.

A summary of AEMO's assessment on this issue is shown below in Table 5.

Table 5 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Status quo – charge all generators and market network service providers on average market share of output (MWh) and capacity (MW)	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Treating all generators the same does not distort incentives in wholesale market and may avoid discrimination by charging some more than others. • Reflects involvement, but only so far as all generators must pay their share of core NEM cost and uses the tariff (MWh/MW) to reflect the extent of involvement • A minor amendment may be to include SGA/MASPs/DRSPs. Cons • Doesn't charge material non-scheduled and semi-scheduled generators a higher rate, particularly in the earlier years, to reflect their increased involvement in AEMO's revenue requirements
Separate cost allocation for VRE only – charged on average share of output (MWh) and capacity (MW) of VRE only; *AND* **Status quo for all other generators – charged on average market share of output (MWh) and capacity (MW)**	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Based on survey results, reflects the extra involvement with AEMO's revenue requirements from managing the VRE transition in the earlier years the fee period. Cons • Less simple • Although it may be reasonable, different charges for VRE generators may be discrimination

4.2.3 AEMO's draft proposal

- AEMO proposes to:
  - Maintain the existing approach of allocating core NEM costs to all Generators (including MNSPs) based on an average share of output (MWh) and capacity (MW), and also include SGA's and MASPs/DRSPs from 1 July 2021;
  - SGAs, MASPs, DRSPs will be charged similarly to generators using the wholesale market data available for these participants, for example FCAS enablement and capacity data;

[8] As shown in Figures 4 and 5 of AEMO's Electricity Fee structure Consultation Paper published in August 2020.

- Maintain the existing percentage allocation of 46% to generators for the first two years of the next fee period, that is the transition period; then
- Increase the percentage allocation to generators to 56% from 1 July 2023, reflecting an increased level of involvement with revenue requirements for AEMO's core NEM activities.

It is also proposed that the specific division of costs to Non-market generators (2/3, 1/3), as outlined in section 4.2.1, is removed. As per current arrangements, no Generators and MNSPs costs will be apportioned to Non-Market Non-Scheduled Generators.

The above proposal is recommended for the following reasons:

- Maintains simplicity of the generator fee and avoids discriminating between generators, while continuing to have regard to the NEO.
- Reflects the results from the core NEM cost allocation survey, to the extent practicable.
- The approach will, over time, inherently take account of the increased level of involvement of VRE in AEMO's revenue requirements related to the NEM compared to other generators.
- There is no clear reason based on the fee structure principles or having regard to the NEO, nor stakeholder support, to change from the existing MWh/MW fee metric.
- A transition period will allow participants to factor the increased allocation of NEM fees for commercial reasons.

4.3 Market customer tariff

4.3.1 Issues summary and submissions

Market Customers are allocated a significant proportion of the budgeted costs which is reflective of a Market Customers involvement with AEMO's budgeted revenue requirements and having regard to the NEO.

Market Customers have a direct allocation (FRC function costs), a share of core NEM allocation, and the unallocated amount (overheads). Market Customers may also be allocated a share of energy transformation projects, like 5MS and DER integration.

The existing arrangement is to charge the core NEM and unallocated amounts on a $/MWh basis, and the FRC costs on a $/NMI basis.

The key issue is whether a "variable" $/MWh, a "fixed" $/NMI or an alternative tariff is more consistent with the Rules requirements having regard to the NEO.

The variable $/MWh tariff may encourage consumers to reduce, at the margin, electricity use. For example, a variable tariff may encourage a large smelter to reduce consumption, or a residential customer being encouraged to reduce consumption either directly or through investment in solar PV or demand-side management initiatives.

Currently a Market Customer with a consumer that has a rooftop PV will be charged on a "net" basis; that is, exports from the NMI will be deducted from consumption, reducing the fees paid. This effectively means that a customer without rooftop PV is paying more than a customer with rooftop PV, which may result in a Market Customer with a low proportion of customers with solar rooftop PV effectively being treated differently to a Market Customer with a higher proportion of consumers with rooftop PV, which may not be consistent with the non-discriminatory principle.

There were six submissions that responded to this issue – a summary of the main proposals for a market customer tariff is provided below.

Table 6 – Summary of stakeholder views on market customer tariff

Option	Number of stakeholder responses	General comments
Continue with existing net variable tariff ($/MWh)	3	• A change to the current metric requires further understanding on whether the change would facilitate more equitable allocation of costs • $/MWh tariff is a simple metric and is less likely to distort market customer incentives as it correlates more with their revenue than the alternatives
Change to a fixed $/NMI tariff	1	• Accounts for variable behind-the-meter generation, notably solar PV
Charging on a gross energy consumption basis	2[9]	• Allocates fees to participants who can offset their energy use
Combination of both $/MWh and $/NMI tariff	2	• More balanced approach as $/MWh and $/NMI has different impacts on different market customers • Reduces the effect of a pure $/MWh approach where NMIs with solar PV bear a lower proportion of the relevant costs than NMIs without solar PV

4.3.2 AEMO's assessment

AEMO assessed the four main options put forward by stakeholders, including consideration of the data that could be obtained from AEMO's systems, particularly from the 5MS and Global Settlement systems upgrade, which could provide data on imports and exports at the NMI level.

A summary of AEMO's assessment is shown below in Table 7.

Table 7 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Status quo – variable charge $/MWh	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Very simple • Uses MWh to reflect involvement at a participant level • Results in consumers that use the most paying the most Cons • Misrepresents MWh as an ideal metric to reflect involvement in NEM allocated costs. • AEMO's costs don't vary with energy use – may encourage consumers, at the margin, to avoid consuming electricity • If consumption is not as forecast in a year, recovery differs from the budgeted amount • May have poor incentives re: rooftop PV and batteries, which avoid these costs – placing costs onto other consumers
Fixed charge $/NMI	Simplicity Reflective of involvement	Pros • Reflects AEMO's costs don't vary with energy use, so should not discourage electricity consumption • Easier to ensure recovery • Uses NMIs to reflect involvement at a participant level

[9] This includes support from two stakeholders who both supported other options.

	Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	• Ensures all consumers pay the same irrespective of rooftop PV, battery Cons • Moving to 100% NMI charge would have a large redistributive effect without a clear basis for doing so. • Misrepresents NMI as an ideal metric to reflect involvement in NEM allocated costs.
Gross $/MWh charge on imports and exports	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Has regard for the NEO by addressing the current net metering approach i.e. NMIs with solar PV are bearing a lower proportion of the relevant costs than NMIs without solar PV Cons • This option would not be simple to implement and the implementation cost would need to be considered with regard to the NEO.
Combination of $/MWh and $/NMI charge (50/50 split)	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Recovery in part on a $/NMI basis does not have the netting issue/where PV offsets the load • Allows a greater level of certainty of fee recovery through the fixed tariff • Recognises that neither NMI or MWh are ideal metrics upon which to charge participants (and their consumers). Cons • Is not as simple as a fully fixed or fully variable tariff

4.3.3 AEMO's draft proposal

It is proposed that the Market Customer tariff:

- Maintain the existing percentage attribution of the core NEM allocated fee to Market Customers for the two-year transition period, that is from 1 July 2021. In the transition period, the current method of a rate per MWh for a financial year would be used; then
- From 1 July 2023, the percentage attribution of the core NEM allocated fee to Market Customers is reduced and is amended to a combination of $/MWh and $/NMI on a 50/50 allocation; and

- Maintain the attribution of the unallocated costs to Market Customers for the duration of the fee period. This is considered to remain an appropriate method for recovering unallocated costs from Registered Participants that are closest in the electricity supply chain to end users.

This is proposed for the following reasons:

- Is reflective of the level of involvement from Market Customers regarding revenue requirements for core NEM activities due to the increase in TNSPs and DNSPs involvement with AEMO's revenue requirements as a result of AEMO's activities specifically undertaken for TNSPs and DNSPs.
- Although a fully fixed $/NMI tariff may seem to discriminate in favour of larger consumers, this is not unreasonable as a consumption tariff is not more reflective of involvement in AEMO's revenue requirements.
- Stakeholder feedback has identified consumers are responsive to energy prices and will seek to reduce consumption accordingly, therefore introducing a $/NMI tariff, in part, appears appropriate to account for this so that Participant fees should recover the budgeted revenue requirements for AEMO.
- Recognises that neither NMI or MWh are ideal metrics upon which to charge participants (and their consumers) therefore, on balance, a combined fixed and a variable tariff demonstrates greater consistency with the fee structure principles and has regard to the NEO.

4.4 Charging NSPs

4.4.1 Issues summary and submissions

Currently TNSPs and DNSPs are not allocated any of the core NEM function fees. Traditionally, the rationale for this, particularly for TNSPs, was due to the interdependent relationship with AEMO. In the past there was also a dependency on the TNSPs in fulfilling AEMO functions, for example through TNSP Operating Agreements, however this is no longer the situation.

As the NEM has transitioned to a more complex environment as outlined in section 2, there is an increasing amount of AEMO's activities being undertaken for TNSPs and DNSPs to manage power system security and power system reliability.

Such activities for TNSPs can include transmission limits advice, transmission outage scheduling, voltage control, contingency analysis, and operational timeframe system strength and inertia assessment for TNSPs. Meanwhile, DNSP involvement with AEMO's revenue requirements has increased due to DER management – particularly rooftop solar PV curtailment in periods of low demand for the South Australian network and a similar situation emerging in Queensland – as well as the development of PSCAD models in Victoria and New South Wales to assess distribution-level generator connections and performance standards.

Consequently, there needs to be consideration on whether NSPs should be charged some of the core NEM function fees.

However, if AEMO is to charge TNSPs Participant fees, there also needs to be consideration on how costs would be allocated in Victoria taking into account the division of TNSP functions between the provider of shared network services in Victoria (AEMO) and the network operators (Declared Transmission System Operators, primarily AusNet Services).

Additionally, transitional arrangements to enable alignment with regulatory control periods or some other cost recovery mechanism should also be considered to allow NSPs to recoup their Participant Fees.

A number of stakeholders commented explicitly on extending the NEM fee charge to NSPs, a summary of which is provided below.

Table 8 – Summary of stakeholder views on charging NSPs

Option	Number of stakeholder responses	General comments

Continue with existing allocation of NEM fee charges	8	• Charging NSPs who do not have a direct relationship with end-use consumers will result in additional administrative costs being passed onto consumers • AEMO fees determination will need to align with NSP regulatory determinations to allow these parties to include them in their regulated revenue allowances
Extend the NEM fee charge to NSPs	2	• There are a number of other AEMO activities that are now undertaken for NSPs

4.4.2 AEMO's assessment

AEMO's cost allocation survey indicated that the level of involvement with TNSPs and DNSPs has increased since the previous fee determination process. While the allocation to DNSPs is much less than the allocation to TNSPs, it is expected that DNSP involvement is likely to grow over time as the impact of the levels of DER penetration increase.

The issue raised by stakeholders on the need to align the AEMO fees determination with NSP regulatory control periods, while recognising that TNSP regulatory control periods are not aligned, was also considered in AEMO's assessment of charging NSPs. Consideration of this raised options of transitional arrangements to allow time for TNSPs and DNSPs to seek a rule change to enable recovery or provide other administrative arrangements for cost recovery before the Participant fees charged to these participants becomes effective.

The results of the cost allocation survey showed that TNSP involvement with AEMO's revenue requirements is operational in nature (excluding TNSP involvement in AEMO's planning of the national transmission network which is captured by NTP function fees, see section 4.5 below). In Victoria, TNSP involvement with AEMO's activities do not relate to AEMO's declared network functions and are instead attributable to AusNet Services who is responsible for operating and maintaining the Victorian transmission network.

Specifically, the operational activities can include:

- Development, coordination and provision of mainland PSCAD models to TNSPs. This allows TNSPs to perform their generator connection and system security studies.
- Determining synchronous generator combinations for maintaining system strength and inertia under system normal, outage and islanding conditions. AEMO provides the results of the analysis to TNSPs who then use this as part of their transmission limits advice.
- Determining how system security and quality of supply can be maintained under some complex outages. TNSPs have Network Outage System (NOS) requests that they submit to AEMO, however systems analysis is not performed by them to ensure that their requested network outages do not negatively impact system security and reliability due to other constraints or outages such as Generator planned outages. AEMO therefore undertakes this analysis on behalf of the TNSPs.
- Other operational interactions with TNSPs at the real-time, short-term and medium-term timeframes occur when a transmission line trips, voltage issues arise and also when contingency analysis violations are alerted.

A summary of AEMO's assessment is shown below in Table 9.

Table 9 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Status quo – no charge to TNSPs or DNSPs	Simplicity	Pros N/A
	Reflective of involvement	Cons

	Not unreasonably discriminate	• Based on the cost allocation survey results, this is not reflective of the involvement of NSPs with AEMO's revenue requirements
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	
Separate allocation to TNSPs and DNSPs (on the basis of energy consumed as per the NTP function fee metric)	Simplicity	Pros • Consistent with cost allocation survey results which showed significant involvement of TNSPs with AEMO's revenue requirements and some involvement with DNSPs Cons N/A
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	

4.4.3 AEMO's draft proposal

Based on AEMO's assessment, it is proposed that from 1 July 2023 AEMO separately allocate core NEM costs to TNSPs[10] and DNSPs as per the survey results (other than NTP function costs), on the basis of energy consumed.

It is proposed to charge TNSPs and DNSPs for the following reasons:

- Charging Participant Fees to these participants would be consistent with the reflective of involvement principle as initial survey results indicate TNSPs' material involvement and some level of involvement from DNSPs with AEMO's revenue requirements for operational activities.
  - The level of involvement of DNSPs is expected to increase moving forward, particularly as the level of DER increases.
- The nature of AEMO's interaction with TNSPs and DNSPs has changed since the last determination through the operational activities AEMO now performs for TNSPs and DNSPs. Such activities for TNSPs can include analysis for transmission limits advice and transmission outage scheduling, voltage control and contingency violations analysis, development, coordination and provision of mainland PSCAD models for generator connection and system security studies, as well as system strength and inertia assessments for TNSPs under various operational conditions.
- Despite several uncertain administrative arrangements and timing and transitional issues associated with charging TNSPs and DNSPs Participant Fees under the Rules, these issues and uncertainties are not strong considerations in deciding whether to allocate costs and charge Participant Fees to NSPs as part of AEMO's determination.
- To ensure that charging methodologies do not cause significant difficulties in terms of their ability to be recovered by a particular TNSP or DNSP, the proposed transition period (i.e. retaining the current core NEM allocation to Generators and Market Customers) is intended to provide sufficient time for TNSPs and

[10] In Victoria, for the purposes of Participant fees, the TNSP being AusNet Services.

DNSPs to seek the necessary transitional arrangements to be put in place for all TNSPs and DNSPs to recover the fees before the participant fees are charged to TNSPs and DNSPs.

4.5 NTP function fee

4.5.1 Issues summary and submissions

Prior to 1 July 2020, the costs incurred by AEMO in providing NTP services (referred to in the Rules as 'NTP function fees') were recovered from Market Customers under AEMO's existing participant fee determination.

From 1 July 2020, the Integrated System Planning Rule (ISP Rules) required the ISP to replace the initial stages of the RIT-T process, that is the Project Specification Consultation Report (PSCR), for projects made actionable by the ISP, providing a ready-made modelling suite with assumptions, transparent justifications for actionable projects and greater certainty of success once a project has been determined actionable. The ISP Rules also required AEMO to allocate NTP function fees to TNSPs, rather than Market Customers.

In the process of implementing the ISP Rules, AEMO and the TNSPs identified a number of administrative and transitional issues related to the budgeting and charging of NTP function fees to TNSPs. On 20 August 2020, AEMO submitted a non-controversial rule change request to the AEMC to enable realisation of the policy intent of the ISP Rules in relation to the recovery of NTP function fees.

On 29 October 2020, the AEMC made a final rule under an expedited rule change process that commenced on the same day and was consistent with the proposed rule submitted by AEMO in its rule change request. The key features of the rule change are:

- Introduction of a new obligation on AEMO to allocate NTP function fees between Coordinating NSPs (CNSPs), and to advise each CNSP by 15 February each year of the NTP function fees payable by that CNSP in the next financial year, to enable the CNSP to include those fees in the transmission prices it publishes by 15 March or 15 May;
- Clarifications that NTP function fees will also be recovered by AEMO in its capacity as a CNSP in Victoria for the declared shared network, and that AEMO in its capacity as a CNSP will subsequently recover these fees from Victorian distribution businesses and other transmission connected customers through transmission use of system (TUOS) charges and not participant fees;
- Transitional provisions which enable part of the published NTP function fees for 2020-21 to be levied on CNSPs, and the remainder to be levied on CNSPs in 2021-22, together with any NTP function fees incurred in previous years which AEMO has not yet recovered (plus AEMO's cost of financing these amounts); and
- Transitional provisions to enable CNSPs to recover through transmission prices for the 2021-22 financial year any NTP function fees charged to them during the 2020-21 financial year which they were not able to reflect in their transmission prices for the 2020-21 financial year.

The effect of the final rule is that allocation of NTP function fees to CNSPs over the period from 1 January 2021 to 30 June 2022 will be based on 2019 consumption levels. The decision to defer any changes to the fee structure for NTP function fees until 30 June 2022 ensures that the NTP function fees expected to be incurred by AEMO in 2021-22 (and notified to CNSPs by 15 February 2021) are not impacted by AEMO's current consultation on participant fees.

There were three stakeholders who responded on the charging methodology for the NTP function, all of which supported the approach of consumption on a per GWh basis from 1 July 2022.

4.5.2 AEMO's assessment

AEMO's rule change request involved close collaboration with the ENA and explored various options to address the key issues identified its proposal. The process to develop the rule change request included an options assessment and decision by AEMO and the ENA to settle on the proposed changes described above.

Additionally, charging TNSPs for the NTP function, rather than Market Customers would mean:

- Costs are recovered from the participant category which is most involved in the activities undertaken as part of the function, that is, consistent with the reflective of involvement principle; and
- The recovery of costs would not unreasonably discriminate other participants of which the NTP function activities do not directly impact.

4.5.3 AEMO's draft proposal

Consistent with the AEMC's final determination, the allocation of NTP function fees to CNSPs from the commencement of the new fee structure, 1 July 2021, to 30 June 2022 will be based on 2019 consumption levels.

From 1 July 2022 until the end of the fee structure period, AEMO proposes to levy TNSPs based on their respective jurisdiction's consumption (per GWh basis) for the latest completed financial year. This charging mechanism is consistent with that used in the AEMC's final rule and takes into account AEMO's close collaboration with the ENA in developing the charging mechanism, which included an assessment of alternative options.

4.6 Electricity Retail Markets fee

4.6.1 Issues summary and submissions

Currently, Electricity Retail Markets fees, currently known as Full Retail Contestability (FRC) fees, are charged to Market Customers on a per NMI basis which has been in effect since 1 July 2019 as a result of the 2015 fee determination. This fee were originally intended to separately recover the costs of full retail contestability, that is to largely reflect the cost of implementing and operating MSATS, and transition arrangements were in place for jurisdictions as they progressively adopted FRC.

The 2017 consultation on FRC fees confirmed the same charging arrangements should remain, and also that third party B2B participants would not pay fees in the short term but is an area that would be reviewed.

Since the inception of the FRC service fee, the activities that are allocated to this category have changed and there needs to be recognition that this fee now encompasses more than just pure FRC (or MSATS) related activities. The fee now also includes a proportion of costs relating to other retail functions as well as the B2B platform, which utilises a 'Shared Market Protocol' that was implemented as part of Power of Choice (PoC) with the intention of facilitating additional services including those with third parties.

Other changes since the FRC fee was introduced include:

- The introduction of Metering Coordinators as part of the introduction of metering competition;
- Significant changes to MSATS resulting from the 5MS program; and
- Going forward there is likely to be more interaction with the retail market and functions e.g. through the 5MS and DER integration programs.

Five stakeholders provided feedback on this issue as shown below in Table 10.

Table 10 – Summary of stakeholder views on the FRC / retail markets fee

Option	Number of stakeholder responses	General comments
Continue with status quo – recovery from market customers on a $/NMI basis	2	• $/NMI basis is more equitable than a $/MWh basis as the latter favours customers with small loads which are more likely to have less sophisticated systems increasing complexity of AEMO's management • Rationale for moving to $/NMI basis in 2019 has not changed

Change the charging metric – recovery from a broader participant base (e.g. metering coordinators) either on $/MWh or per transaction basis	3	• $/NMI approach creates difficulty for the AER when calculating the DMO and for the ESC when calculating the VDO • The fee should be applicable to any market customer that has a direct customer billing relationship

4.6.2 AEMO's assessment

AEMO assessed whether recovery of the current FRC fee should be extended to Metering Coordinators due to the introduction of this participant category as a result of the PoC reforms which came into effect in December 2017. AEMO's assessment found that while the number of Metering Coordinators in the NEM has increased since the previous fee structure determination, their level of involvement with the revenue requirements for AEMO retail activities is not material enough to consider in this fee determination. Further, there could be administrative costs that may be passed on to consumers should this participant category be charged which would not be efficient or in the long-term interests of consumers.

When investigating the appropriate charging metric for the Electricity Retail Markets fee, it was noted the alternative option of using transaction data doesn't necessarily indicate a significantly higher involvement of one retailer than another because customers' demands on retailers and meter data providers (who work for retailers) is largely the same. Additionally, the retailer "market share" basis of recovery better reflects this function's purpose to the industry and consumers, as opposed to the MWh consumption basis of recovery. This is because AEMO's electricity retail markets capability is built to handle a total number of individual meters and the actual energies flowing through them is incidental.

A summary of AEMO's assessment is shown below in Table 11.

Table 11 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Status quo – recovery from market customers on a $/NMI basis (not extending the charge to metering coordinators)	Simplicity	Pros • $/NMI provides a level of certainty for cost recovery • $/NMI is relevant and appropriate charging metric for the retail market • Aligns with AEMO's cost allocation survey showing an immaterial level of involvement with metering coordinators Cons • Does not capture specific use of CATS/MDM/B2B systems
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	
Change to recovery from market customers on a per transaction basis	Simplicity	Pros • Captures specific use of CATS/MDM/B2B systems Cons • Charging on a per transaction basis is complex • Because transactions can vary, recovery of AEMO's budget is not ensured
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	

4.6.3 AEMO's draft proposal

It is proposed to continue with the status quo option of recovering Electricity Retail Markets fee from Market Customers (continuing to exclude metering coordinators from recovery) and on a per connection point ($/NMI) basis.

The approach of allocating cost on a per connection point basis has largely the same distributive effect to the end consumer as the per transactions approach, and using MSATs and B2B data would in fact make the fees more complex and provide no improvement in economic efficiency.

It is proposed not to charge metering coordinators as there was immaterial level of involvement of metering coordinators with AEMO's revenue requirements indicated by the cost allocation survey.

4.7 Cost recovery of the 5MS program

4.7.1 Issues summary and submissions

The Five-Minute Settlement program (5MS program), which coordinates the implementation of changes as a result of the Five-Minute Settlement rule change and the Global Settlement (GS) rule change, is not reflected in the current fee structure and as its implementation is due during 2021, a mechanism to recover its costs from relevant registered participants, the charging metric and the period of recovery, need to be determined.

On 28 November 2017, the AEMC made a final determination and rule to alter the settlement period for the wholesale electricity spot market from 30 minutes to five minutes, to align with the dispatch period. On 6 December 2018, the AEMC made a final determination and rule that requires a move to a Global Settlement framework for the demand side of the wholesale electricity market. In November 2019, AEMO published its final decision that determined the 5MS Program met the criteria in the NER to be a declared NEM project pursuant to clause 2.11.1(ba)(1) and clause 2.11.1(ba)(3) of the NER.

However, AEMO did not determine a separate participant fee for 5MS at that time, and instead is considering the participant fee structure for 5MS in this consultation.

5MS and GS requires major changes to wholesale systems and processes (settlement, prudentials, and bidding/dispatch) and retail systems and processes (metering and MSATS). These changes may be categorised as follows:

- Changes that may be considered as 'legacy upgrades', i.e. the IT systems require a technology uplift due to their age and technology, which can be expected as part of any systems life cycle; and
- Changes that may be considered as '5MS/GS specific upgrades', i.e. the IT systems must be changed to give effect to the 5MS and GS rule changes specifically.

It is efficient to complete both types of changes in a single program, to do otherwise would be highly inefficient. Implementation of the program will have impacts on many classes of registered participants, including Market Customers (electricity retailers), distribution businesses, as well as generation and demand side technologies.

A number of stakeholders responded to this issue, the majority of which supported recovery of the costs of the 5MS program over 10 years. A summary of the main options put forward by stakeholders on a fee structure for the 5MS program is provided below in Table 12.

Table 12 – Summary of stakeholder views on the cost recovery of the 5MS program

Option	Number of stakeholder responses	General comments
Allocated to the Core NEM fee with recovery from all existing participants	5	• It is appropriate to allocate these costs to all participant categories involved in the activities on a $/MWh basis • Allocating costs as broadly as possible upon customers is appropriate as there are direct and indirect benefits across a number of different participant categories
Allocated to the Core NEM fee with recovery from market customers only	1	• Benefits flow to all market customers and will be greater when more energy is used

4.7.2 AEMO's assessment

AEMO considers that legacy upgrades are "business-as-usual" investments, and should be recovered through the relevant "business-as-usual" fee recovery mechanism. Whereas 5MS/GS specific upgrades are distinct and should be recovered through a separate fee recovery mechanism.

Additionally, for the above categories of upgrades, costs can be further attributed in the following manner:

- Legacy upgrades can be apportioned to either wholesale or retail; and
- 5MS/GS specific upgrades can equally be apportioned to either wholesale or retail.

Based on this, the following table highlights AEMO's assessment of the options for 5MS cost recovery.

Table 13 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment

Separate function in fee structure **Adopting project accounting structure, allocate costs directly to relevant participant categories; otherwise adopt Core NEM allocations** **[Distribute costs directly to Market Customers and Generators, then use Core NEM split for anything remaining.** **Use the tariffs for FRC, Generator and Market Customers.]**	Simplicity	Pros • Cost allocation reflects involvement of specific participants • Reduces risk of not recovering all of the budget requirements through the NEM fee • Costs are recovered more efficiently in the longer-term from those who benefit/involved with the systems Cons • Slightly more complex cost allocation
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	
Use the Core NEM cost allocation survey (excluding NSPs)	Simplicity	Pros • Socialises costs across all participants therefore less reflective of involvement but more simple Cons • Doesn't take into account different 5MS costs i.e. legacy vs 5MS specific • In the longer-term some participants will continue to pay for the upgrades when they're not necessarily benefiting from them
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	

4.7.3 AEMO's draft proposal

It is proposed that AEMO recover the total costs (capex and opex) of the 5MS and GS Program over a period of 10 years (commencing from 1 July 2021) in the following manner:

- Legacy upgrade costs are treated as business-as-usual investments and recovered through the relevant AEMO fee.
  - For legacy upgrades associated with wholesale systems (settlements and prudentials, bidding and dispatch): These costs will be aggregated into, and recovered through, the core NEM fee from Market Customers and Generators only. NSPs are to be excluded from 5MS cost recovery. The NSP allocations will be normalised into the Market Customer and Generator allocations. Please refer to section 3.2 to review the allocation and recovery methodology for the core NEM fee.
  - For legacy upgrades associated with the retail systems (metering, MSATS): These costs will be aggregated into, and recovered through, the Electricity Markets Retail fee.
- 5MS specific costs are treated as a stand-alone item and recovered through a new, separate cost recovery fee line item. The 5MS fee will be apportioned across Market Customers and Generators. The percentage allocation has been derived on the following basis:
  - 5MS/GS specific upgrade costs for Bidding/Dispatch are entirely allocated to Generators.

- 5MS/GS specific upgrade costs for Settlements are allocated between Market Customers and Generators in line with the split in effect for the core NEM fee. NSPs are to be excluded from 5MS cost recovery. The NSP allocations will be normalised into the Market Customer and Generator allocations.
- 5MS/GS specific upgrade costs for Retail (Metering and MSATS) are entirely allocated to Market Customers.

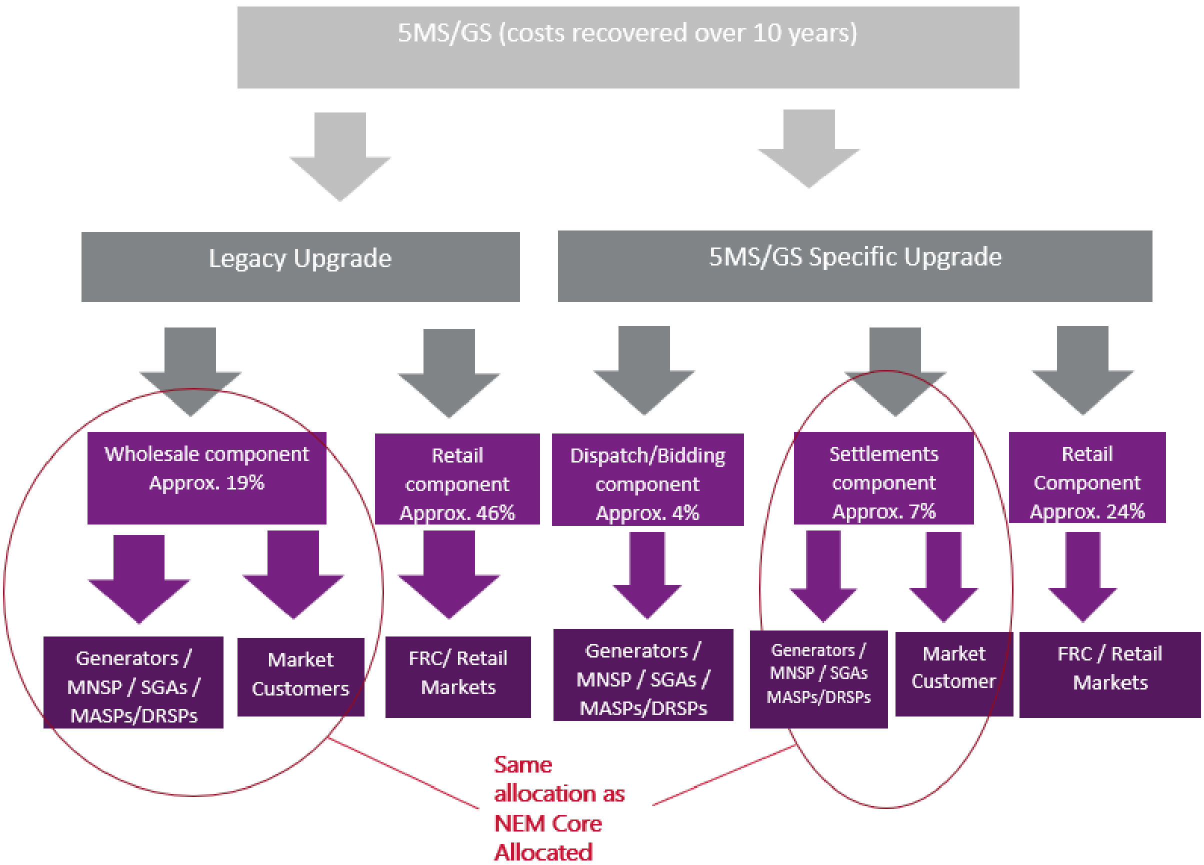
This allocation is based on a review of the costs incurred on the 5MS Program.

AEMO's draft proposal is made for the following reasons:

- It is strongly aligned, to the extent practicable, with the reflective of involvement principle.
- The use of the existing tariff structures for the legacy upgrade costs of Electricity Retail Markets (Market Customers) and core NEM (Generator and Market Customer tariffs), ensures the overall structure remains simple and doesn't unreasonably discriminate between categories of participants.
- Treating legacy and 5MS specific upgrades separately makes the approach more complex, but more transparent and better reflects participant involvement:
  - Legacy costs are more suited to use the cost allocation of the survey as they are costs incurred to manage obsolescence in NEM systems.
- Commencing from 1 July 2021 as IT systems are 'live' from the end of Q1 2021.

The figure below shows the proposed cost allocation for 5MS recovery.

Figure 3 – AEMO's proposed allocation for cost recovery of the 5MS program



4.8 Cost recovery of the DER integration program

4.8.1 Issues summary and submissions

DER integration is not covered in the current fee structure but is an integral program to evolve the national electricity system for the future, particularly given the rate of uptake of DER that is occurring and projected. The program involves initiatives that AEMO is working on in partnership with the Energy Security Board (ESB), market bodies, and stakeholders to design and implement the technical integration of DER.

The DER integration program comprises:

- Consumer data – DER register and the Energy Consumer Data Right
- Markets – to bring these resources into the wholesale market (WDR, VPPs)
- Operations – identify emerging and future operational challenges related to DER, developing and implementing suitable mitigation measures
- Standards – minimum technical requirements to ensure system security and interoperability
- Demonstrations – trials to inform regulatory changes to effectively integrate DER into the grid and markets. This includes, among others VPP demonstration program and Victorian DER Marketplace.

Some of the initiatives, such as the WDR mechanism, will impose considerable costs and therefore an appropriate fee structure for the entire DER integration program needs to be determined for the next fee period. There are also some uncertainties associated with the Energy CDR program, including funding arrangements and timing of implementation, for which a cost recovery approach that can account for those uncertainties should be considered.

About half of stakeholder submissions provided their views on the most suitable cost recovery approach for DER integration and a number of stakeholders responded specifically on the recovery of Energy CDR. This is summarised below in Tables 14 and 15.

Table 14 – Summary of stakeholder views on the cost recovery of the DER integration program

Option	Number of stakeholder responses	General comments
Allocated to the Core NEM fee with recovery from all existing participants	1	• All participants benefit from the program and therefore should be charged for DER integration
Recovered separately from participants who directly benefit from the program	5	• New or existing participants that earn a revenue stream from the reform should be assigned costs more directly • Reflective of involvement approach should be used when recovery costs for programs such as WDR
Recovered on an incremental/as needed basis from market customers only	1	• Retailers have a direct relationship with the end-use consumer, i.e. the end beneficiaries and can therefore pass costs on more efficiently

Table 15 – Summary of stakeholder views on the cost recovery of the Energy CDR program

Option	Number of stakeholder responses	General comments
Allocated to the Core NEM fee with recovery from all existing participants and accredited data recipients on a per data transaction basis	3	• Costs should be recovered from all parties that benefit from the CDR program, including ADRs who will utilise the AEMO gateway to request data from data holders

Allocated to the Core NEM fee with recovery from market customers only on a $/MWh basis	1	• Costs should be recovered from the parties that have a direct relationship with the end-use customer
Recovered as a separate fee on a $/NMI basis	1	• The costs are materially lower than other market operating functions and market customers are well placed to efficiently recover these costs
Recovered from the Government	1	• All ongoing opex costs should be recovered from the Government since they are already providing some funding to AEMO

4.8.2 AEMO's assessment

AEMO considered options proposed by stakeholders as well as the registered participants involved in, or benefit from, AEMO's activities associated with the DER integration program.

Additionally, the program, which is being undertaken in partnership with other market bodies, members and non-members, has been established to explore emerging markets, maintain network stability with high levels of DER and pioneer best-in-class new products and services for consumers. It will create tools and protocols to address short, medium and long-term challenges to prepare AEMO to facilitate energy markets in a high-DER energy system that will enable consumers to have:

- Greater choice and affordability of flexible, personalised energy services and products;
- Access to a secure, reliable and affordable energy supply via a least-cost energy system;
- The ability to maximise value from DER assets and infrastructure (e.g. demand response); and
- The opportunity to engage with a decentralised two-sided energy market and secure, reliable two-way energy system[11].

With the above in mind, an assessment of options to recover the DER program was performed, a summary of which is shown in Table 16 below.

Table 16 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Account for the DER program separately, but using the core NEM survey to allocate costs (assumes MASPs / DRSPs would be incorporated into any tariffs designed for generators) **Defer determination on CDR recovery**	Simplicity	Pros • Attributes costs across all NEM participants, and has regard to the NEO as less likely to deter participation in new markets (WDR/VPP) • Uses existing processes/approach consistent with the core NEM allocations • Is not a complex approach, therefore increases consistency with the simplicity principle Cons • Does not accurately reflect those participants who are involved with, or benefit from, the program
	Reflective of involvement	
	Not unreasonably discriminate	
	Recovery of AEMO's budgeted requirements on a specified basis	
	NEO	
Account for the DER program separately, and use specific allocations for DER costs – **Market customers charged on the basis of $/MWh; Generators/**	Simplicity	Pros • Costs are allocated to those who are involved with, use, or benefit from the program, consistent with the reflective of involvement principle • Not all costs are allocated to the core NEM function Cons
	Reflective of involvement	

[11] For those who have invested in DER as well as those who have not.

MNSPs charged on the basis of $/MWh; MASPs/DRSPs charged on basis of a fixed allocation to recover a reasonable percentage of the establishment cost of the WDR Mechanism **Defer determination on CDR recovery**	Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	• May be considered more complex, therefore less consistent with the simplicity principle • Could potentially deter participation in new markets (WDR), which may be considered less consistent with the NEO

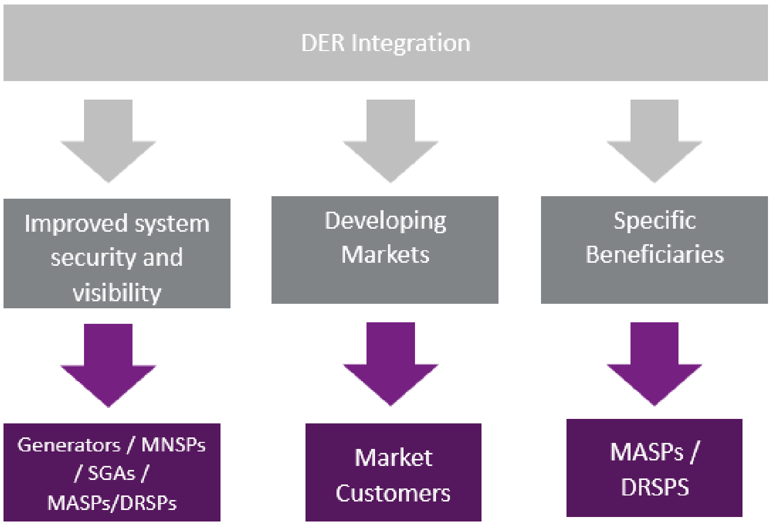
4.8.3 AEMO's draft proposal

It is proposed that the DER program is recovered as a separate function in the fee structure allocated to the relevant participant categories reflective of their involvement in, or benefit from the program, as follows (and shown diagrammatically in Figure 4):

- Majority of the recovery from Market Customers (e.g. approximately 70-80%) for developing markets and products to enable improved participation and competition for consumers, charged on a $/MWh basis;
- Some recovery from Generators, including SGAs/MNSP/MASPs/DRSPs, (e.g. approximately 20%) due to DER integration providing improved system security and visibility, charged on $/MWh basis;
- NSPs excluded, noting that AEMO would reconsider an allocation to NSPs, in particular DNSPs, should the distribution market operator (DMO) / two-sided market reforms progress, either through a declared NEM project under the Rules within the next fee period, or subsequent fee structure review; and
- A separate specific allocation to MASPs/DRSPs on the basis of a fixed charge to recover a reasonable percentage of the WDR mechanism establishment (capital) costs (e.g. up to 10%) at the end of the fee period. Annual opex would be fully recovered from the relevant participating Registered Participants:
  - The quantum recovered each year could be phased in over time based on actual participation as the market matures. A fixed rate will be set each year i.e. $/MW or $/Capability registered to participate in the WDR mechanism;
  - Any fees charged to MASPs/DRSPs as beneficiaries of the WDR mechanism would need to be implemented from 1 July 2022, rather than the first year of the fee period, because the WDR commences in October 2021 and attempting to account for implementation timing may result in difficulty estimating a fee for the 21/22 financial year.

The above approach, while not as simple as the first option outlined in Table 16, holistically will provide greater consistency with the fee structure principles and has regard to the NEO since the DER program will involve or benefit various participant categories across the program.

Figure 4 – Proposed cost recovery of the DER integration program (excluding Energy CDR)



Additionally, it is proposed to defer a determination on the recovery of the Energy CDR program for the Draft Report, although there is potential for the program to meet the criteria of a declared NEM project. The reasons for a deferral at this point in time include:

- The CDR rules and standards, as they apply to the energy sector, have not yet been finalised and thus the exact scope of the roles AEMO will play are yet to be detailed;
- The ACCC are presently considering a phasing approach to the roll out of the CDR, therefore it is not yet clear which retail market participants may be subject to obligations under the CDR, and thereby are involved or benefit from the program; and
- Amendments to the NEL and NER, to enable AEMO to play its roles in the CDR program and recover associated costs, have not yet been finalised.

As these issues begin to be addressed over the first half of 2021, AEMO will be able to more meaningfully engage with our members on the expected costs of delivering and operating our CDR services and therefore in a better position to determine an appropriate means of cost recovery of the program. It should be noted however that any engagement with our members on CDR costs and cost recovery is outside the scope of the current fee structure review.

4.9 Cost recovery of the Digital and Regulatory Compliance programs

4.9.1 Issues summary and submissions

AEMO expects to incur significant capital expenditure over the next few years on its digital program as a result of AEMO's systems nearing end-of-life. Additionally, the significant increase in data volumes necessitates an increase in computational capability, analytics, design, and digitalisation to support the real-time operation of AEMO's energy systems and markets.

Regulatory compliance programs are changes required to market systems, processes or regulatory instruments for AEMO to comply with NEM regulatory changes and are directly related to the NEM core functions.

The current approach for these activities is to use the existing high-level accounting through the core NEM function to allocate costs, which uses the existing tariffs for Generators and Market Customers.

Only two stakeholders provided views on the recovery of both the digital and regulatory compliance programs supporting recovery from the core NEM fee across all existing registered participants. One of these stakeholders also commented that criteria similar to that used for declared NEM projects could be applied to determine the recovery of larger regulatory projects in the future.

4.9.2 AEMO's assessment

AEMO has assessed options for the recovery of the digital and regulatory compliance programs in Table 17 below.

Table 17 – AEMO's assessment of options against the NEO and NER principles

Most feasible options	Principles assessment	Comments on principles assessment
Allocating directly to core NEM Participant categories (including TNSPs) **Declared NEM project process can be used for significant reforms**	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Allocates cost to the appropriate participant categories, reflective of involvement or benefit from the regulatory compliance and digital programs • Significant regulatory compliance activities can be treated as NEM declared projects, or have already been accounted for in DER Integration or 5MS • There is no one participant class that should be exposed to the costs Cons • Some participants may not benefit from the programs as much as others but still have to pay for it
Allocating across broader fee structure functions, including core NEM, FRC/retail, NTP etc. **Declared NEM project process can be used for significant reforms**	Simplicity Reflective of involvement Not unreasonably discriminate Recovery of AEMO's budgeted requirements on a specified basis NEO	Pros • Recovers costs for these programs across all functions/fees, not just core NEM • Significant regulatory compliance activities can be treated as NEM declared projects, or have already been accounted for in DER Integration or 5MS Cons • More complex • Requires allocation on a case-by-case basis • Could lead to discriminatory allocation/cost recovery

4.9.3 AEMO's draft proposal

The proposed position is to allocate directly to the core NEM fees participant categories (including NSPs) in the following manner:

- For the digital program, the costs are to be recovered from both the NEM allocated and unallocated categories.
- For the regulatory compliance program, the costs are to be recovered from the NEM allocated category.
- For significant regulatory reforms, AEMO proposes to apply the declared NEM project framework, where required.

This approach is proposed because:

- It is likely that all projects related to digital and regulatory compliance requirements will provide benefit broadly across all NEM participants.
- It is less complex than recovering across the broader fee structure as projects will not need to be assessed on a case-by-case basis.
- Assessment of projects on a case-by-case basis may lead to unreasonable discrimination of some participants.
- There was unanimous support from stakeholders for cost recovery across all participants.

5. Other Matters

The table below summarises other fee structures under consultation which AEMO has assessed and proposes continuing with their current fee structures. This proposal was unanimously supported by stakeholders who provided responses to them.

Table 2 – ECA, NEM PCF, Registrations and Incremental service fees

Fee	Current approach	Summary of stakeholder views	Options assessment / Recommendation
ECA	In October 2014 AEMO conducted a consultation process, prior to the commencement of the ECA, and it was determined that the electricity component of ECA fees would be recovered from NEM customers on the basis of a charge per connection point for small customers	2 stakeholders responded and supported the current approach	It is considered the $/NMI charge is simple and aligns with the NEO for the charging of small customers. Recommendation is to continue with the status quo
NEM PCF	AEMO currently charges NEM PCF fees to Scheduled Generators, Semi-scheduled Generators and Scheduled Network Service Providers on a 50% capacity and 50% energy basis	Only one stakeholder responded and supported the current approach	It is considered the 50/50 capacity/energy split for scheduled and semi-scheduled generators and NSPs remains appropriate and meets all NER principles, particularly the simple and non-discriminatory principles as well as the NEO. Recommendation is to continue with the status quo
Registration	Registrations fees reflect the costs to AEMO in the registration of all registered participants in the NEM. This review is not considering the quantum, only the structure.	3 stakeholders responded with two of those supporting a review of the registration fee itself, i.e. the quantum, which is not under consideration in this review	Recommendation is to continue with the status quo until the upcoming review on the quantum of registration fees is determined.
Incremental service fees	Where it is practical for AEMO to identify that doing something specific for a participant or another party, and that action causes identifiable and material costs for AEMO, AEMO seeks to levy fees to recover the incremental costs incurred.	2 stakeholders responded supportive of avoiding complexity by excluding services as incremental that are required under ordinary participation services	It is considered the current approach remains simple and reflective of involvement. Recommendation is to continue with the status quo

6. Appendix A: Fee structure principles

In determining the structure of Participant fees, AEMO must have regard to the NEO and the structure of Participant fees must, to the extent practicable, be consistent with number of principles.

The fee structure principles are set out in the table below with an explanation and some examples of how these requirements may be applied to reviewing the electricity fee structure.

Table 1 Principles applicable to fee structures

Fee Structure Principle	Requirement	Application and examples
National Electricity Objective (NEO)	In determining Participant fees, AEMO must have regard to the national electricity objective. The objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to— (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system	The Second Reading Speech to the National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005 makes it clear that the NEO is an economic concept and should be interpreted as such. The Speech gives an example that investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources, including infrastructure, are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The Speech goes on to state that the long-term interests of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the NEM is efficient in an economic sense, the long-term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised. Applying an objective of economic efficiency recognises that, in a general sense, the NEM should be competitive, that any person wishing to enter the market should not be treated more, or less, favourably than persons already participating, and that particular energy sources or technologies should not be treated more, or less, favourably than others. Since 2006, the NEO has been considered in a number of Australian Competition Tribunal determinations, which have followed a similar interpretation. See, for example, Application by ElectraNet Pty Ltd (No 3) [2008] ACompT [15]: "The national electricity objective provides the overarching economic objective for regulation under the Law: the promotion of efficient investment in the long term interests of consumers. Consumers will benefit in the long run if resources are used

		efficiently, i.e. resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost." The NEO is clearly a relevant consideration where AEMO has to exercise judgment or discretion in reaching its determination, for example, if there is a number of Participant fee structures each of which can satisfy the Fee Structure principles, or where the relevant provisions of the Rules are ambiguous.
Simplicity	The structure of Participant fees should be simple	As "simple" is not defined in the Rules, it must be given its ordinary meaning as understood in the context of clause 2.11 of the Rules. The New Shorter Oxford English Dictionary's definition of "simple" (in this context) is: "not complicated or elaborate" and "plain, unadorned". Whether a fee structure fits these definitions is largely a matter of judgement. There is a wide range of possible fee structures. There is no single identifiable point where "simple" becomes "complicated". It is clear from this provision that a certain degree of complexity was envisaged in that the structure of Participant fees may involve several components and budgeted revenue consists of several elements. The structure of Participant fees need not demonstrate absolute simplicity. The simplest fee structures are unlikely to be consistent with the other criteria. However, it is possible to find fee structures that, while consistent with the other criteria, are relatively simple, in comparison to alternative structures. Further, AEMO considers that the use of the word "simple" in this context also involves a degree of transparency. AEMO considers that the simplicity principle means that the basis of the fee structure and its application to various Registered participants should be: • straight-forward • easily understood by participants • readily applied by Registered participants and AEMO • foreseeable and forecastable in terms of impacts and costs.
Reflective of Involvement	The components of Participant fees charged to each Registered Participant should be reflective of the extent to which the budgeted revenue requirements for AEMO involve that Registered Participant	In determining whether the extent to which the budgeted revenue requirement relating to a particular output involves a class of Registered Participant, AEMO relies on the experience and expertise of its general managers and staff, and considers factors such as the degree to which the class of Registered Participant: (a) interacts with AEMO in relation to the output;

		(b) uses the output; (c) receives the output; and (d) benefits from the output. AEMO also considers how the revenue requirements are given rise to, or caused by, that class of Registered Participant's presence in the NEM. AEMO must determine the structure of Participant fees "afresh". That is, it must freshly consider the application of the criteria in clause 2.11.1 of the Rules and the NEL to the facts and analysis available to it at this time. In doing so, however, AEMO will have regard to its previous determinations under clause 2.11.1 of the Rules, where appropriate. The principle of "reflective of extent of involvement" does not have a specialised meaning in economics. It is consistent with the economic notion of 'user pays' but as a matter of ordinary language, it indicates a degree of correspondence (between AEMO and its costs and participants) without connoting identity. However, this principle does not involve a precise degree of correspondence. Where fixed and common costs are involved, multiple registered participants may be involved with AEMO costs in relevantly similar ways. AEMO's analysis and experience shows that there are categories or classes of Registered Participants that share certain characteristics that mean that the way in which they interact with AEMO is likely to have the same or similar cost implications for AEMO. Where it is practical for AEMO to identify costs that are fixed or common in nature that can reasonably be allocated to a class or classes of Participants that share characteristics such that their involvement with AEMO's outputs is likely to have the same or similar cost implications, AEMO will seek to do so.
Non-discriminatory	Participant fees should not unreasonably discriminate against a category or categories of Registered Participants	In past Participant Fee determinations, AEMO (and its predecessor, NEMMCO) adopted the following definition of discriminate: "Discriminate means to treat people or categories of people differently or unequally. Discriminate also means to treat people, who are different in a material manner, in the same or identical fashion. Further, "discriminate against" has a legal meaning which is to accord "different treatment … to persons or things by reference to considerations which are irrelevant to the object to be attained". This principle allows AEMO to discriminate against a category or categories of Registered participants where to do so would be reasonable. Where a degree of discrimination between categories of Registered Participants is necessary or appropriate to achieve consistency with the other

		principles in clause 2.11.1(b) of the Rules, or the NEL, the discrimination will not be "unreasonable". In considering a past fee determination, the Dispute Resolution Panel accepted that this principle is to be applied to the extent practicable and it is only unreasonable discrimination that offends.

7. Appendix B: Draft structures for Participant Fees

AEMO's draft structures for Participant Fees for the next fee period in comparison to the existing fee structure.

Table x: Comparison of proposed fee structures for the next fee period with the existing structure[12]

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
National Electricity Market	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Generators and Market Network Service Providers of which: (i) two-thirds is apportioned to Market Generators in respect of their market generating units, Non-Market Scheduled Generators in respect of their non-market scheduled generating units, Semi-Scheduled Generators in respect of their semi-scheduled generating units and Market Network Service Providers in respect of their market network services; (ii) one-third is apportioned only to Market Generators in respect of their market generating units and Market Network Service Providers in respect of their market network services; and (iii) none is apportioned to Non-Market Non-Scheduled Generators in respect of their non-market non-scheduled generating units.	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Generators and Market Network Service Providers and SGAs and MASPs/DRSPs of which: (i) does not apportion two-thirds to Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs or one-third to Market Generators and MNSPs. – Generator and Market Network Service Provider and SGAs and MASPs/DRSPs charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Generators, Market Network Service Providers, SGAs and MASPs/DRSPs; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs the equivalent FCAS enablement, scheduled or metered (in previous calendar year). – Market Customers charges: Rate per MWh for a financial year based on AEMO's	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 23% Market Customers; (b) 56% Generators and Market Network Service Providers and SGAs and MASPs/DRSPs of which: (i) does not apportion two-thirds to Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs or one-third to Market Generators and MNSPs; (c) 18% to Transmission Network Service Providers; and (d) 3% to Distribution Network Service Providers. – Generator and Market Network Service Provider and SGAs and MASPs/DRSPs charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Generators, Market Network Service Providers, SGAs and MASPs/DRSPs; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs the equivalent FCAS enablement, scheduled or metered (in previous calendar year). – Market Customers charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year.

[12] Note, the final allocation for each fee structures will be provided in this review's Final Report and Determination.

	– Generator and Market Network Service Provider charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity in the previous calendar year of generating units and market network services; and (ii) 50% charged as a daily rate based on MWh energy scheduled or metered (in previous calendar year). – Market Customers charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customers charges – Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period.	estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customers charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period.	Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. – Transmission and Distribution Network Service Provider charges: charged on the basis of energy consumed for the latest completed financial year. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customers charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week.
Electricity Retail Markets	• From 1 July 2016 to 30 June 2019: – Charged to Market Customers with a retail licence and levied for a financial year at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers with a retail licence during that financial year against regional reference nodes. Rate applied to actual spot	• No change to existing structure.	• No change to existing structure.

	market transactions in the billing period. • From 1 July 2019 to 30 June 2021: – Charged to Market Customers with a retail licence and levied on a per connection point basis per week.		
National Transmission Planner	• From 1 July 2016 to 30 June 2020: – Charged to Market Customers and levied at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • From 1 July 2020 to 30 June 2021: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels.	• From 1 July 2021 to 30 June 2022: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels. • From 1 July 2022 to 30 June 2023: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.	• From 1 July 2023 to 30 June 2025: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.
5MS program	• NA	• For 5MS legacy upgrade costs: – Wholesale component: same allocation as transition period NEM allocated fee structure to Generators/MNSPs/SGAs/MASPs/DRSPs and Market Customers (excluding TNSPs and DNSPs) levied on the same basis as above for NEM; and – Retail component: same allocation as Electricity Retail Markets fee to Market Customers levied on the same basis. • For 5MS/GS specific costs: – Dispatch component: 100% allocation to Generators, MNSPs, SGAs and MASPs/DRSPs levied on the same basis as the transition period NEM allocated fee charging of Generators, MNSPs, SGAs and MASPs/DRSPs; – Settlements component: same allocation as transition period NEM allocated fee	• For 5MS legacy upgrade costs: – Wholesale component: same allocation as final NEM allocated fee structure to Generators/MNSPs/SGAs/MASPs/DRSPs and Market Customers (excluding TNSPs and DNSPs) levied on the same basis. The NSPs allocations are to be normalised into the Generators and Market Customer allocations; and – Retail component: same allocation as Electricity Retail Markets fee to Market Customers levied on the same basis. • For 5MS/GS specific costs: – Dispatch component: 100% allocation to Generators, MNSPs, SGAs and MASPs/DRSPs levied on the same basis as the final NEM allocated fee charging of Generators, MNSPs, SGAs and MASPs/DRSPs; – Settlements component: same allocation as final NEM allocated fee structure to Generators, MNSPs, SGAs and MASPs/DRSPs and Market Customers (excluding TNSPs and DNSPs) levied on the same basis as above for NEM. The NSPs allocations are to be normalised into the

		structure to Generators, MNSPs, SGAs and MASPs/DRSPs and Market Customers (excluding TNSPs and DNSPs) levied on the same basis as above for NEM; and – Retail component: same allocation as Electricity Retail Markets fee to Market Customers levied on the same basis.	Generators and Market Customer allocations; and – Retail component: same allocation as Electricity Retail Markets fee to Market Customers levied on the same basis.
DER program	• NA	• From 1 July 2021 to 30 June 2022: – 70-80% Market Customers levied on a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. – 20% Generators, MNSPs, SGAs and MASPs/DRSPs levied on the same basis as above for NEM. • From 1 July 2022 to 30 June 2023: – 70-80% Market Customers levied on a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. – 20% Generators, MNSPs, SGAs and MASPs/DRSPs levied on the same basis as above for NEM; and – <10% DRSPs levied on a fixed charge to recover a reasonable percentage of the WDR mechanism establishment costs.	• 70-80% Market Customers levied on: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. • 20% Generators, MNSPs, SGAs and MASPs/DRSPs levied on the same basis as above for NEM; and • <10% DRSPs levied on a fixed charge to recover a reasonable percentage of the WDR mechanism establishment costs.
Energy Consumers Australia	• Charged to Market Customers and levied at a rate per small customer (as defined in the National Energy Retail Law) connection point.	• No change to existing structure.	• No change to existing structure.

NEM Participant Compensation Fund	• Charged to Scheduled Generators, Semi Scheduled Generators and Scheduled Network Service Providers in accordance to the NER, levied on 50% maximum capacity and 50% energy generated in the previous calendar year.	• No change to existing structure	• No change to existing structure.
Registration fees	• The fee structure for registration fees for each application type to continue to be charged. • The actual registration fee amounts are to be set as part of the annual budget.	• No change to existing structure.	• No change to existing structure.
Incremental charges	• Where it is practical for AEMO to identify that doing something specific for a participant or another party, and that action causes identifiable and material costs for AEMO, AEMO can seek to levy fees to recover the incremental costs incurred.	• No change to existing structure.	• No change to existing structure.

8. Appendix C: Registered participants

A range of Registered Participants are part of the electricity market and benefit from the services that AEMO provides.

Below is a summary of registered participants.

Table 2 Registered participants

Participant category	Description	Registered participant class
Generators	Any person who owns, controls or operates a generating system connected to a transmission or distribution network	• Market Scheduled • Market Non-scheduled • Market Semi-scheduled • Non-market Scheduled • Non-market Non-scheduled • Non-market Semi-scheduled
Small Generation Aggregator	An SGA can supply electricity aggregated from one or more small generating units, which are connected to a distribution or transmission network. A small generating unit is owned, controlled and/or operated by a person who AEMO has exempted from the requirement to register as a generator.	• Market Small aggregated generator
Customers	A customer is a registered participant that purchases electricity supplied through a transmission or distribution system to a connection point	• Market customer • First-tier customer • Second-tier customer
Network Service Providers	A person who owns, operates or controls a transmission or distribution system	• Transmission network service provider • Distribution network service provider • Market network service provider
Special Participant	A delegate appointed by AEMO to carry out, on AEMO's behalf, some or all of AEMO's rights, functions and obligations under Chapter 4 of the Rules. A Distribution System Operator who is responsible, under the Rules or otherwise, for controlling or operating any portion of a distribution system (including being responsible for directing its operations during power system emergencies).	• System operator • Distribution system operator
Reallocator	Anyone that wishes to participate in a reallocation transaction undertaken with the consent of two market participants and AEMO	• Reallocator
Trader	Anyone who wants to take part in a Settlements Residue Auction (SRA), and is not already registered as a customer or generator	• Trader

Metering Coordinator	Has the overall responsibility for coordination and provision of metering services at a connection point in the NEM	• Metering coordinator
Market Ancillary Service Provider (MASP) / Demand Response Service Provider (DRSP)[13]	Delivers market ancillary services in accordance with AEMO's market ancillary services specifications, by offering a customer's load, or an aggregation of loads into FCAS markets.	• Market ancillary service provider • Demand response service provider

[13] The DRSP category will enter the market once the WDR mechanism commences in October 2021 and we expect those currently registered as MASPs in the VPP program will register as a DRSP.

9. Appendix D: Stakeholder submissions and AEMO response

Stakeholder	Main issues from stakeholders' submissions	AEMO response
Essential Energy	• Recovery base should not be extended to DNSPs	• AEMO's assessment through the cost allocation survey identified the relevant participants involved and their level of involvement in each of AEMO's activities. • AEMO's draft position as outlined in section 4.4.3 of the Draft Report is that for the first 2-years (transition period) NSPs will not be charged. Thereafter, NSPs will be charged separately reflective of their involvement identified through the cost allocation survey.
Red/Lumo	• Transparency and efficiency are paramount – want further transparency on $500M debt facility (AEMO should publish a full cost benefit analysis of all prospective, in progress and completed market changes and projects e.g. 5MS)	• The scope of this consultation does not include the quantum of AEMO's budgeted revenue requirements. Transparency and opportunity for stakeholder feedback on the quantum will be provided through AEMO's consultation on its budget expected to commence in Q1 2021.
	• Electricity retail markets fee charge should be changed to $/MWh	• AEMO's assessment as outlined in section 4.6.2 of the Draft Report found that retailer "market share" basis of recovery better reflects a participants involvement with the revenue requirements for this function, as opposed to the MWh consumption basis of recovery. This is because AEMO's electricity retail markets capability is built to handle a total number of individual meters and the actual energies flowing through them is incidental. • A $/NMI basis will also better ensure recovery of AEMO's budgeted requirements than a variable charge.
	• Participant base should not be broadened to NSPs or Metering Coordinators	• AEMO's assessment through the cost allocation survey identified the relevant participants involved and their level of involvement in each of AEMO's activities. • AEMO's draft position is that NSPs are charged (following the 2-year transition period) but metering coordinators will not be charged for reasons outlined in sections 4.4 and 4.6 respectively.
	• Support a 5-year fee term	• AEMO's draft position as outlined in section 4.1.3 of the Draft Report is a 5-year fee period with a 2-year transition period to allow the changes AEMO is proposing to be implemented efficiently while still aligning with the NER principles. • The 5-year determination also provides participants with greater certainty over costs, as well as providing AEMO with more certainty regarding costs to be recovered over a longer period.
	• CDR recovery should be from those with direct relationship with customer	• AEMO's draft position as outlined in section 4.8.3 of the Draft Report is for the CDR cost recovery determination to be deferred until there is further certainty on requirements and impacts of the CDR program.

EUAA	• Support a NEO driven fee structure (more so than the principles)	• As per clause 2.11.1 of the NER, AEMO's draft positions on the fee structure have regard to the NEO and to the extent practicable, are consistent with the principles.
	• Support a longer-term fee period	• Please see AEMO's response to Red/Lumo.
	• Would like to see data from AEMO's cost allocation survey – attribution to customers should be a transparent public consultation	• AEMO's results from the cost allocation survey are reflected in the Draft Report in Figure 1 and also outlines the kinds of involvement participants have with AEMO's revenue requirements.
	• Recovery base should be extended to any participant in the electricity markets	• The rules require the fee structure to be to the extent practicable consistent with the reflective of involvement principle and AEMO's assessment through the cost allocation survey identified the relevant participants involved and their level of involvement in each of AEMO's activities. • AEMO's draft position has been detailed in section 3.2 of the Draft Report.
	• Support continuing recovery of ECA fees on per connection point basis	• Noted and this is reflected in the Draft Report.
ENA	• Supportive of a simple fee structure	• As per clause 2.11.1 of the NER, AEMO's draft positions on the fee structure have regard to the NEO and to the extent practicable, are consistent with the principles.
	• Note recent CEPA report on AEMO's governance found that AEMO's members have very little input into developing AEMO's business plan and its budget relative to other organisations with similar roles – suggest better engagement is welcomed on AEMO's operations, associated cost levels and importantly, governance controls over that budget	• In 2021 AEMO is conducting a review on its governance and operating models, including consideration of the system operator scope, legal structure, funding and regulatory models used in other jurisdictions as a result of changes in the industry including a major increase in both market obligations and operational complexity. Based on the requirements of the rules, the discussions on a new operating model and any outcomes from those discussions will not form part of matters considered in the consultation on the electricity fee structure.
	• Do not support allocation of costs to NSPs, DRSPs or non-energy synchronous services	• For charges to NSPs please see AEMO's response to Essential Energy. • For charges to DRSPs please see AEMO's response to EUAA.
	• Supportive of NTP charging proposal	• AEMO's draft position as outlined in section 4.5.3 of the Draft Report is that NTP fees are charged on their respective jurisdiction's consumption for the latest completed financial year and equal monthly invoicing as per the AEMC's Final Determination and Rule on the Reallocation of NTP costs published on 29 October 2021.
	• Supportive of DER recovery from market customers (retailers)	• AEMO's assessment as outlined in section 4.8.2 of the Draft Report found that DER workstreams will impact all registered participants through involvement of AEMO activities associated with the DER workstreams. • AEMO's draft position is outlined in section 4.8.3 of the Draft Report that the DER program is recovered as a separate function in the fee structure allocated to the relevant participant categories reflective of their involvement – this includes allocation to generators, market customers as well as specific beneficiaries such as DRSPs (on the basis of a fixed charge to recover a reasonable percentage of the WDR mechanism establishment costs from commencement of the WDR mechanism).

PIAC	• Simplicity principle should be reconsidered – allocating fees is complicated. Transparency, efficiency and fairness are more appropriate principles to guide the fee structure	• The scope of this consultation does not include redefinition or amendments to the NER principles that guide the determination of the fee structure.
	• Support a 3-year fee period	• AEMO's draft position as outlined in section 4.1.3 of the Draft Report is a 5-year fee period with a 2-year transition period to allow the changes AEMO is proposing to be implemented efficiently while still aligning with the NER principles. • The 5-year determination also provides participants with greater certainty over costs, as well as providing AEMO with more certainty regarding costs to be recovered over a longer period. • The 3-year period provides less certainty to participants on costs.
	• Support reviewing division of costs between market generator categories and consideration of charging non-energy synchronous services	• Please see AEMO's response to EUAA.
	• Welcomes more consideration of the likely impacts of a reallocation of fees currently recovered through the FRC fee	• AEMO's draft position on the electricity markets fee as outlined in section 4.6.3 is that costs will be recovered from market customers on a $/NMI basis – AEMO's cost allocation survey indicates minimal involvement of AEMO activities from metering coordinators.
	• DER workstreams primarily relate to or benefit small customers and/or inverter-connected DER. DRSPs may not benefit from majority of projects in the DER workstream as they are engaged by larger customers	• Please see AEMO's response to the ENA.
EQL	• AEMO's revenue requirements (including its debt funding approvals) and participant fee structure should be subject to enhanced scrutiny and governance (consider there is a need for AEMO to cap its future operating and capital expenditure at a reasonable level to minimise costs for customers)	• The scope of this consultation does not include the quantum of AEMO's budgeted revenue requirements. Transparency and opportunity for stakeholder feedback on the quantum will be provided through AEMO's consultation on its budget expected to commence in Q1 2021.
	• Further consideration and information is needed on broadening participant recovery base e.g. anticipated extent of the additional costs, how costs can be budgeted for and recovered, along with details of the services the fees will contribute towards and consideration is needed on implementation timing	• Please see AEMO's response to the EUAA.
	• Support 5-year term	• Please see AEMO's response to Red/Lumo.
	• Support market customer charging on $/MWh basis	• AEMO's assessment as outlined in section 4.3.2 of the Draft Report has found that: – Having regard to the NEO, a full variable charge may be inefficient as consumers are responsive to energy prices and will seek to reduce consumption or install PV, which if done at the margin, to avoid AEMO fees, leads to inefficiency because these costs are not avoided. This does not have adequate regard to the NEO in AEMO's view. – A fully fixed tariff may unreasonably discriminate in favour of participants with large loads, however provides more certainty of cost recovery of AEMO's budgeted requirements than a variable tariff.

		• AEMO's draft position on the market customer charge is to remain unchanged for the first 2-years of transition, thereafter changing to a 50/50 split between $/NMI and $/MWh approach as this will be more consistent with the NER principles while still having regard to the NEO.
	• If DRSPs are charged, they should only be charged once WDR mechanism commences	• AEMO's assessment found that attempting to charge DRSPs prior to commencement of the WDR mechanism would be too complex. • AEMO's draft position is that DRSPs will only be charged after the WDR mechanism commences in October 2021.
AEC	• Support 5-year fee period	• Please see AEMO's response to Red/Lumo / EQL.
	• Supports recovering fees from other participants like MASPs, traders, reallocators etc i.e. supports reflective of involvement principle	• Please see AEMO's response to EUAA.
	• Generator charging – supports increasing fees to non-market and non-scheduled gens as well as MASPs and WDR providers; may be appropriate for semi-scheduled generators to pay slightly more; supportive of a 50/50 capacity-energy basis; Large-scale battery storage impact could be resolved through FCAS enablement volume charge	• AEMO's draft position is SGAs/MASPs/DRSPs should be incorporated into a generator charge for reasons outline in section 4.2.2 of the Draft Report. The approach will need to use data such as FCAS values to represent capacity and energy (the metrics used for generators). • AEMO's draft position is not to charge semi-scheduled generators slightly more than other generators for reasons substantiated in the Draft Report in section 4.2.3. • AEMO's draft position in section 4.2.3 also outlines the reasons for removing the 2/3-1/3 split to market/non-market scheduled/semi-scheduled generators and MNSPs vs market generators and MNSPs. • On maintaining a 50/50 capacity-energy basis, this is noted in the report.
	• Agrees that there are other AEMO activities that are undertaken for NSPs	• Please see AEMO's response to Red/Lumo.
	• A big gap in the current structure relates to charging solar/variable BTM generation, charging options include: – shifting some of the Market Customer Fee from per MWh to a per NMI basis; – charging Market Customers fees for their customers' exports; – charging Market Customers fees according to the number of solar systems recorded as installed in their customer base; and/or – charging on "gross" customer energy consumption through a deeming technique	• AEMO's draft position on the market customer charge is to remain unchanged for the first 2-years of transition, thereafter changing to a 50/50 split between $/NMI and $/MWh approach for reasons outlined in AEMO's response to EQL. • AEMO has considered the use of gross metered data and this is discussed in the Draft Report in section 4.3.2.
	• Major reform initiatives should be allocated as broadly as possible; CDR should be recovered from ADRs on a per data transaction basis	• AEMO's draft position is for the CDR cost recovery determination to be deferred until there is further certainty on requirements and impacts of the CDR program.
Energy Australia	• Support transparent and regular review of AEMO's activities, budgets, and costs	• The scope of this consultation does not include the quantum of AEMO's budgeted revenue requirements. Transparency and opportunity for stakeholder feedback on the quantum will be provided through AEMO's consultation on its budget expected to commence in Q1 2021.

	• Support a shorter fee period (2 or 3 years)	• Please see AEMO's response to PIAC.
	• Not supportive of recovering charges from metering or network parties; support recovering from market participants that have a direct customer billing relationship i.e. non-scheduled gens, non-market gens, semi-scheduled gens, large-scale battery storage, MASPs/FCAS providers, WDR providers and SGAs; AEMO should consider charging ENSPs and ADRs for their respective services when they enter the market even though they have indirect and complex relationship with market participants	• Please see AEMO's response to Red/Lumo / EUAA.
	• Option for charging market customers: – a combination of both per MWh and per NMI basis (similar to 50/50 capacity/energy basis for gens) or – a weighted fee per NMI based on the consumption of customer and their associated costs to AEMO's operations	• Please see AEMO's response to EQL / AEC.
	• Generator charging – supports assigning costs incurred to accommodate non-market, non-scheduled, and semi-scheduled generators and 50/50 capacity-energy basis remains appropriate	• Please see AEMO's response to AEC.
	• FRC charge should be changed to $/MWh basis	• Please see AEMO's response to RED/Lumo.
	• Major reform initiatives should be allocated more specifically to those who benefit; CDR should be allocated to ADRs as well as retailers on per data transaction basis	• Please see AEMO's response to Red/Lumo / AEC on the CDR.
AGL	• Support five year term for fee structure	• Please see AEMO's response to Red/Lumo / EQL / AEC.
	• AEMO fees should be recovered from all participants that earn a profit directly from the NEM (including MASPs, Market Stand Alone Power Service Providers, and ENSPs as they become more active). It may be more efficient to exclude participants such as TNSPs, DNSPS, and metering coordinators as likely to pass through to customers (except to the extent that they are involved in activities beyond their role as contemplated in the NER)	• AEMO is to be consistent with the principles under 2.11.1(b) of the NER to the extent practicable and must have regard to the NEO when determining the fee structure. The clause 2.11.1(b), in particular (3), does not limit involvement to having a billing and settlement relationship with AEMO.
	• Generators - supports continuation of 50/50 capacity/energy basis for and believes all generators should be charged on equal basis (consistent with simplicity and reflective of involvement principles)	• AEMO's draft position largely reflects the point made by AGL.
	• Market customers – support current $/MWh method of charging on actual energy consumed. Supports change to gross $/MWh flow for each NMI	• Please see AEMO's response to EQL. • AEMO has considered the use of gross metered data and this is discussed in the Draft Report in section 4.3.2.
	• NTP fee – supports AEMO's proposal	• Please see AEMO's response to the ENA.
	• FRC fee – supports $/NMI basis	• Please see response to Red/Lumo / Energy Australia.

	• Major reform initiatives: – 5MS – allocation should be on per MWh basis to market customers, suggest consideration of shorter repayment period – DER – should be determined for each specific DER initiative under reflective of involvement approach – Digital/cyber – fees spread across all participants – Regulatory compliance – support using NEM declared project criteria for larger Reg projects and suggest smaller Reg projects are recovered through general allocated bucket – CDR – recommend that all ongoing costs for maintenance/management of the Gateway and AEMO's role as a data holder, be covered by the Government	• AEMO's assessment of 5MS program and costs found that greater transparency and cost allocation that is more reflective of involvement (than allocation solely to market customers) can be provided and therefore AEMO's draft position reflects this in section 4.7.3. • For AEMO's assessment and draft position on DER recovery, see response to PIAC. • On the cost recovery of the Digital and Regulatory compliance programs – this is reflected in the Draft Report and this approach is consistent with all NER principles and NEO for these programs. • For recovery of CDR, see response to Red/Lumo / AEC.
	• Support continuation of other fees as per status quo approach	• Noted and this is reflected in the Draft Report
Enel X	• Major reform initiatives: – DER – five work streams include wide range of programs – not clear which of these programs the incremental costs might relate to – In allocating any residual costs to DRSPs to fund the incremental costs of the DER programs, AEMO will need to consider carefully the degree to which DRSPs directly benefit from or use the program in order to meet the "reflective of involvement" principle. – WDR mechanism attributable to DRSPs while remainder of projects have wider pool of users/beneficiaries and not always relevant to DRSPs	• For AEMO's assessment and draft position on DER recovery, please see response to PIAC / AGL. •
	• Registration fee – agree with AEMO's proposal	• Noted.
AusGrid	• Any proposed changes to the way participant fees are structured must recognise the ability of market participants to recover those costs and must result in more efficient allocation of costs among market participants – Transparency and consultation required on cost allocation survey	• Please see AEMO's response to the ENA. • A transitional period of 2 years is proposed to allow time for NSPs to seek cost recovery arrangements. • On the cost allocation survey see response to EUAA.
	• Term of new fee structure – shorter period (ie 3yrs) might be more appropriate. Transitional arrangements required on commencement of any new obligation on DNSPs	• Please see AEMO's response to PIAC / Energy Australia.
	• Allocating AEMO's costs to broader group of market participants may not promote NEO due to greater admin burden across industry – Regulated businesses may not have ability to recover new costs as not been included in expenditure forecasts. Long lead times required to factor costs into regulatory determination processes – Not clear functions performed by DNSPs are sufficiently linked to AEMO's systems such that distributors can be	• Please see response to the Essential Energy / ENA / AusGrid.

	said to have given rise to AEMO's costs; recognise a future where DNSPs required to pay participant fees – informed by P2025 review	
Mondo	• Recommends maintaining with current fee structure to maintain an efficient, beneficiary pays approach, and avoid adverse impacts to competition.	• Please see AEMO's response to the EUAA.
	• Contestable service providers may not have ability to pass on unforeseen costs to customers due to long term contracts. Could adversely impact competition.	• As per clause 2.11.1 of the NER, AEMO's draft position on the fee structure have regard to the NEO and to the extent practicable, are consistent with the principles set out in clause 2.11.1(b). Please refer to section 4.6 of the Draft Determination for discussion on using transaction data.
	• Major reform initiatives: – Notes DER integration, 5MS and digital platform/cyber initiatives primarily provide benefits to the wholesale market – support retaining allocation of fee-paying responsibilities (i.e. market customers, generators and consumers) – CDR – mirror funding arrangements for FRC costs on a per connection point basis	• Please see AEMO's response to AGL on cost recovery for major reform initiatives.
Origin	• Supports structures that are simple, transparent and provide for the equitable allocation of costs to registered participants – Caution against making any changes that would materially increase the complexity of fees charged	• As per clause 2.11.1 of the NER, AEMO's draft positions on the fee structure have regard to the NEO and to the extent practicable, are consistent with the principles.
	• Supports allocating costs to a broader group of registered participants	• Please see AEMO's response to the EUAA / AGL / AEC
	• Supports shorter fee term – 3 year period to capture new participants entering the market	• Please see AEMO's response to Energy Australia / Ausgrid
	• Generator charging – broadly supports existing allocation to generators – further analysis required on whether other metrics will be equitable	• Please see AEMO's response to the AEC. • Additionally, as per clause 2.11.1 of the NER, AEMO's draft positions on the fee structure have regard to the NEO and to the extent practicable, are consistent with the principles.
	• Market customer charging – supports existing $/MWh charge to customers on net energy basis	• Please see AEMO's response to EQL
	• NTP fee – supports AEMO's proposal	• Please see AEMO's response to ENA / AGL
	• FRC fee – Supportive of costs being attributed to a broader group of registered participants (e.g. MASPs/DRSPs, MCs, MDPs) that utilise FRC (MSATS) functions on $/MWh basis	• Please see AEMO's response to Red/Lumo
	• Major reform initiatives: – 5MS – costs that are 5MS specific should be allocated to all participants involved on $/MWh basis (i.e. market customers, MDPs, MCs, MASPs) – DER – costs should be recovered from DNSPs/DRSPs on $/MWh basis – CDR – costs of ongoing delivery should be on a 'user-pays' basis from market participants and ADRs	• Please see AEMO's response to AGL / Mondo

ERM Power	• Previous determinations have been overly simplistic rather than focussing on reflective of involvement principle – Potentially simplicity principle be replaced with transparent – there is lack of transparency in how AEMO's fees are justified and spent	• AEMO must comply with the current NER in determining fees, specifically 2.11.1. • The scope of this consultation does not include changes to the NER principles.
	• AEMO needs to demonstrate why all overhead (unallocated) costs should be allocated solely to market customers – should be split same way as allocated fees	• AEMO distributes allocated costs directly to classes of participants e.g. like retail or through the survey, which is to satisfy 2.11.1(b)(3) – reflective of involvement. The nature of the unallocated overheads is that these costs cannot be allocated this way. • This has been covered by previous determinations, without restating those previous reasons, the reason for charging Market Customers is due to it being impracticable to allocate the overheads costs directly or via the survey approach. It is "least inefficient" to charge overheads to the participant that is as close to the consumer as possible – Market Customers.
	• Supports 4 or 5 year fee period to examine P2025 outcomes	• Please see AEMO's response to Red/Lumo / EQL / AEC / AGL.
	• Support recovery from all registered participant classes who participate in/derive revenue from energy, market and NMAS and any future markets developed e.g. SGAs, DRSPs, batteries/ESS but start with modest contribution in early phase of the new few structure e.g. 5% rising by 1% each year to 10% at the end of a 5 year fee structure – categories could be: – Energy Market Allocated Costs - at more granular sub-categories level where NS gens recovery based 100% capacity and SS gens/S gens based on 50/50 split – Market/NMAS Allocated Costs with separate cost recovery methodology with 50/50 split to Gens and Market Customers for the latter	• Please see AEMO's response to EUAA / AEC. • The allocation of non-market ancillary services (NMAS) costs is not in scope of this determination.
	• Change market customer charge to a split \$/MWh and \$/NMI	• Please see AEMO's response to EQL / AEC.
	• Electricity retail markets fee – supportive of \$/NMI approach	• Noted and this is outlined in section 4.6.3 of the Draft Report.
	• Major reform initiatives: – WDR – levied from DRSPs not market customers as DRSPs are main beneficiaries – 5MS – 10 year fee recovery period is supported from 1 July 2021 and splitting costs between market participants – CDR – charged on \$/NMI basis because CDR costs are more likely to increase if the number of connection points increases	• Please see AEMO's response to AGL / Mondo / Origin.