Australian Energy Market Commission

RULE

Rule determination

National Electricity Amendment (Inter-regional settlements residue arrangements for transmission loops) Rule 2025

Proponent

AEMO

25 September 2025

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The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

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Summary

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable final rule that introduces a 'netting off' approach for allocating positive and negative inter-regional settlements residue (IRSR) in transmission loops. This is in response to a rule change request submitted by the Australian Energy Market Operator (AEMO) that sought changes to the National Electricity Rules (NER) to accommodate the creation of a loop in the National Electricity Market (NEM) once Project EnergyConnect Stage 2 (PEC) is operational.

2 The introduction of the transmission loop means we need new arrangements for allocating IRSR. Our final determination enables updated arrangements to be known as soon as possible, ahead of AEMO's integration of PEC into the NEM. The final rule is likely to better contribute to the achievement of the National Electricity Objective (NEO) than the proposal in AEMO's rule change request as it better promotes efficient risk management and thus keeps costs as low as possible for consumers.

3 Under the final rule, IRSR in a transmission loop will be netted off based on the concept of 'net trade'. Netting off is different to the approach proposed in the draft determination, which would have shared negative IRSR between all regions in the loop in proportion to regional demand, and then recovered this from customers via transmission charges. The netting design in the final rule (based on 'net trade') is also different to the netting design we proposed in the directions paper, where negative IRSR would have been netted off in proportion to positive IRSR on other arms of the loop. Detailed analysis and consideration of stakeholder feedback informed these changes.

4 AEMO will have approximately one year to implement the changes made by the final rule before PEC is operational. The rule and its transitional arrangements have been informed by advice received from AEMO on implementation through ongoing bi-lateral engagement. Market participants will also have this time to understand how they need to accommodate the changes made by the final rule in their hedging strategies. Co-ordinating Network Service Providers (CNSPs) will have lead time before March 2026 to accommodate the changes in their transmission price setting.

The final rule is likely to better promote the NEO than other options

5 This rule change considers how to manage financial flows given that the introduction of a loop into the NEM will change the physical flows of electricity.

6 The power flows in a transmission loop behave in a fundamentally different way to power flows on radial interconnectors, due to the physics of electrical circuits. Power flows impact the financial flows around the loop via their impact on the IRSR arising around the loop. Large and unpredictable negative (and positive) IRSR will be an unavoidable outcome of the transmission loop.

7 If we applied the status quo arrangements for allocating IRSR on radial interconnectors, consumers would be exposed to risks from large, unpredictable negative IRSR.

8 We consider that netting off best manages the risks to consumers and keeps costs as low as possible for consumers by allocating IRSR efficiently. Generally speaking, under a netting off approach, positive and negative IRSR assigned to each 'arm' of the loop in a dispatch interval is pooled together. If the resulting (netted) amount of IRSR is positive, it is distributed to settlements residue distribution (SRD) unit holders, and if it is negative, it is recovered from CNSPs.

9 In coming to this decision, we thoroughly considered other options; including the approach

proposed by AEMO in its rule change request, the approaches set out in the draft determination and directions paper, and numerous other options raised by stakeholders throughout this process. We were not satisfied that options that did not involve netting would adequately manage risks and costs for consumers. We consider the final rule also improves the netting design proposed in the directions paper.

10 The final rule - of all the options we considered - best meets the assessment criteria used for this rule change process:

- The netting approach promotes **improved outcomes for consumers** because it supports efficient risk management and distributes costs appropriately between consumers in different regions.
- The netting approach supports **efficient risk management** by allocating IRSR to the party best placed to manage it for both net positive and net negative IRSR, thus promoting lower costs to consumers; and by implementing a solution that will continue to support inter-regional hedging and trade.
- The netting approach is **consistent with good regulatory practice** as it prioritises predictable signals to the market through transitional and reporting arrangements that promote transparency.

The final rule nets off IRSR in transmission loops based on the concept of 'net trade'

11 In this final determination, we refer to the 'net loop IRSR' as being either positive or negative. This refers to the pooled IRSR amount around the loop for each individual trading interval - that is, if the sum of the IRSR is positive, the 'net loop IRSR' is positive, or we have a 'net positive case'. It is important to note that IRSR is assigned to each arm of the loop in accordance with AEMO's methodology before the netting off approach is applied.

12 Under the netting off approach in the final rule:

- the net loop IRSR, when it is positive, will be distributed to SRD unit holders based on the net energy transfer ('net trade') between the connected regions, instead of the physical flows on the interconnectors. This includes in cases where all arms of the loop are accruing positive IRSR. This is different to the netting design we proposed in the directions paper for net positive cases, where the negative IRSR allocated to an individual arm would have been netted from the positive IRSR on other arms, in proportion to the un-netted positive IRSR on those arms.
- the net loop IRSR, when it is negative, will be recovered from the CNSPs in each connected region in proportion to regional demand. 'Regional demand' means each region's total annual electricity consumption over the prior year. This is the same as the approach we proposed in the directions paper for net negative cases.
- settlements residue auction (SRA) proceeds and positive IRSR attributed to any unsold SRD units ('unsold IRSR') will be allocated to the importing region's CNSP. This is the same as the approach we proposed in the directions paper and the draft determination for these cash flows.

13 The final rule does not change the way in which IRSR is distributed for radial interconnectors (that is, the current regulated interconnectors that link two regions without forming part of an inter-regional transmission loop).

We provided additional consultation opportunities to take diverse stakeholder views on board in developing this final rule

14 Throughout the rule change process, we have considered divergent views from multiple stakeholders, and had to balance risks and trade-offs. We used a longer-than-standard rule change process, with several informal and formal consultation opportunities including a directions paper and technical working group session between the draft determination and final determination. This allowed us to consult on a range of options for a revised policy direction to ultimately inform our final determination position.

15 The directions paper (accompanied by indicative rule drafting) proposed a netting off approach for managing IRSR in transmission loops. The revised approach accounted for feedback to the draft determination, our own further analysis of the issues raised in that feedback, our consideration of the party best placed to manage negative IRSR in the loop, and our analysis of other options.

16 In response to the directions paper, retailers, generators and associated industry bodies (referred to collectively as 'market participants' in this determination) strongly opposed netting off, while CNSPs and consumer groups supported it. Market participants particularly noted that it will be difficult for them to manage the risks of price separation under a netting approach for the loop, which will increase costs to consumers.

17 We consider it is the loop itself, rather than netting per se, which may require changes to hedging strategies to enable market participants to manage inter-regional price risk. SRD units are also not the only tool for managing inter-regional price risks. Our final rule requires that enough information is made available to market participants so they can make informed hedging decisions. The Commission recognises that it will take time and resources for market participants to develop their understanding of loop operation and the netting approach in the final rule, and encourages industry bodies to support this learning.

18 Nonetheless, we understand that there are risks with this approach. There has never been a transmission loop in the NEM, and we cannot be sure of IRSR outcomes around the loop until it is in operation, as we do not have operational data or experience to work with. We have used the data and analysis available, alongside economic theory, to make our decision.

We intend to conduct a broader review in future to ensure that SRA and IRSR arrangements in the NEM are fit-for-purpose

19 The Commission intends to conduct a future review of the SRA and IRSR arrangements. This would provide the opportunity to consider them holistically across both radial and looped interconnectors, as we have identified issues through this rule change process that we consider warrant further attention.

20 The NEM Expert Panel Review Draft Report also recently made a draft recommendation that the AEMC should review interconnector hedging arrangements, because stronger inter-regional hedging is likely to be needed to support investment in variable renewable energy. We support the recommendation for a future review by the AEMC and consider it is aligned with our view that this could consider how best to set up the interconnector hedging arrangements for success in the NEM, given the changing generation mix.

21 The AEMC review could consider any changes that would promote liquidity, make the SRD unit a more effective inter-regional hedging instrument, and so promote the interests of consumers. As we cannot be sure of IRSR outcomes around the loop until it is in operation, we consider a review would be most valuable after at least a year of loop operation, taking into account broader market

outcomes.

Netting will commence between 1 October 2026 and 2 November 2026

22 The final rule includes commencement and transitional arrangements to promote a smooth transition to loop operation. These are more comprehensive than in the draft determination and directions paper, in response to stakeholder feedback for more clarity on the commencement of the loop and new rules for the loop. This clarity is important for market participants who use SRD units for hedging inter-regional price risks and for CNSPs who need to forecast cash flows for the purpose of setting transmission prices each year.

23 The final rule defines key dates for the transition to loop operation and new IRSR allocation arrangements. These dates correspond to two key implementation activities that need to occur:

- The loop needs to be represented in AEMO's dispatch systems. The go-live date for these changes is the 'loop operations start date' - which needs to be on or after 1 October 2026 and by no later than 2 November 2026. Loop flows will impact market outcomes from this time.
- AEMO's settlement systems need to be updated to implement the final rule. The go-live date for these changes is the 'loop settlements start date' – which needs to be on or after the 'loop operations start date', but no later than 2 November 2026.

24 Therefore, after the 'loop operations start date', there will be a transmission loop in dispatch. However, before the 'loop settlements start date', the new IRSR settlement arrangements are not able to be implemented and so cannot apply to settlements. This means that for any period between the loop operations start date and the loop settlements start date, the current arrangements for the allocation and distribution of IRSR for radial interconnectors will apply to the loop.

Contents

Tables

Figures

1 The Commission has made a final determination

This final determination is to make a more preferable final rule (final rule) in response to a rule change request submitted by the Australian Energy Market Operator (AEMO) about allocating negative inter-regional settlements residue (IRSR) in transmission loops. The key features of the final rule are described in chapter 3 and chapter 4 and a detailed outline of the final rule is set out in appendix E.

1.1 Our final rule will net off negative IRSR from positive IRSR in transmission loops

The Australian Energy Market Commission (AEMC or Commission) has made a final rule that introduces a 'netting off' approach for allocating positive and negative IRSR in transmission loops. Under this approach, positive and negative IRSR assigned to each 'arm' of the loop in a trading interval is pooled together. If the resulting (netted) amount of IRSR is positive, it is distributed to settlements residue distribution (SRD) unit holders, and if it is negative, it is recovered from Co-ordinating Network Service Providers (CNSPs).[1]

We proposed a netting off approach in our directions paper, although the final rule implements a different netting design after considering stakeholder feedback and conducting our own further analysis.[2] The final rule is also different to the approach proposed by AEMO in its rule change request[3] and the approach in our draft determination.[4] The final rule is likely to better contribute to the achievement of the National Electricity Objective (NEO) than the proposal in AEMO's rule change request. Of the other options considered that did not involve netting, none adequately manages risks and costs for consumers. We consider the final rule improves the netting design proposed in the directions paper and therefore better meets the assessment criteria.

Under the netting off approach in the final rule:

- the IRSR for the loop in each trading interval is pooled into the 'net loop IRSR', which can be either positive or negative.[5]
- the net loop IRSR, when it is positive, is distributed to SRD unit holders based on the net energy transfer ('net trade') between the connected regions.
- the net loop IRSR, when it is negative, is recovered from the CNSPs in each connected region in proportion to regional demand. 'Regional demand' means each region's total annual electricity consumption over the prior year.
- settlements residue auction (SRA) proceeds and positive IRSR attributed to any unsold SRD units ('unsold IRSR') is distributed to the importing region's CNSP.

This approach makes no changes to the IRSR arrangements for 'radial interconnectors' (that is, the current regulated interconnectors that link two regions without forming part of an inter-

1 The CNSP is the Transmission Network Service Provider (TNSP) responsible for coordinating transmission pricing for a region. AEMO is the CNSP for the Victorian region while Transgrid and ElectraNet are the CNSPs for NSW and SA respectively.

2 AEMC, Inter-regional settlements residue arrangements for transmission loops, Directions paper, 19 June 2025.

3 AEMO, Electricity Rule Change Proposal, Integration of Project EnergyConnect into the National Electricity Market (NEM), February 2024, https://www.aemc.gov.au/rule-changes/interregional-settlement-residue-arrangements-transmission-loops ('AEMO's rule change request').

4 AEMC, Inter-regional settlements residue arrangements for transmission loops, Draft rule determination, 12 December 2024.

5 In this final determination, we refer to 'net loop IRSR' as being either positive or negative. This refers to the pooled IRSR amount around the loop for each individual trading interval - that is, if the sum of the IRSR is positive, the 'net loop IRSR' is positive, or we have a 'net positive case'. It is important to note that IRSR is assigned to an arm in accordance with AEMO's Methodology for the allocation and distribution of settlements residue (current version: version 3, published 2 June 2024), before the netting off approach is applied.

regional transmission loop).[6] The Commission intends to conduct a future review of the SRA and IRSR arrangements for both looped and radial interconnectors to assess whether they remain fit-for-purpose in a future National Electricity Market (NEM).

We have also included commencement and transitional arrangements for the final rule to promote a smooth transition to loop operation. While the changes to the National Electricity Rules (NER) made by the final rule will commence on 2 October 2025, the new IRSR arrangements for transmission loops will not take effect until a transmission loop is in operation in the NEM dispatch engine and changes to AEMO's settlement systems have been implemented. The final rule requires this to occur no earlier than 1 October 2026 and no later than 2 November 2026.

1.2 We have considered diverse stakeholder views throughout the rule change process

1.2.1 AEMO's rule change request raised complex issues related to how to allocate IRSR in transmission loops

Project EnergyConnect Stage 2 (PEC) will be a new interconnector linking South Australia (SA) and New South Wales (NSW), which is expected to begin operating by late 2026.[7] PEC will create the first inter-regional transmission loop in the NEM, when integrated with the existing Heywood/Murraylink (VIC-SA) interconnectors and the VIC-NSW Interconnector (VNI). The rule change request did not propose changes to the IRSR arrangements for radial interconnectors.

IRSR behaves in a fundamentally different way in a transmission loop compared with radial interconnectors.[8] In a transmission loop, negative IRSR is expected to arise more often as a normal outcome of efficient dispatch. Negative IRSR can accrue on one or two arms of a loop, while the net IRSR for the loop as a whole is positive. This is due to the spring washer effect - a pricing phenomenon caused by the interaction between how power physically flows in a transmission loop, and the NEM's regional pricing model.[9]

AEMO currently limits negative IRSR on radial interconnectors by imposing dispatch constraints through a process called 'clamping'.[10] However, clamping looped interconnectors to limit negative IRSR when 'net' loop IRSR is positive would interfere with efficient dispatch and lead to under-utilisation of the looped interconnectors, ultimately increasing costs for consumers.

Not clamping the physical flows in the loop supports dispatch efficiency, but gives rise to more frequent positive and negative IRSR, and therefore raises the question of how to allocate the financial flows resulting from the loop. This issue is the subject of this rule change. Chapter 2 discusses the issue and the nature of the risk that it brings about in more detail.

6 Refer to clause 3.6.6(d) and (e) of the National Electricity Amendment (Inter-regional settlements residue arrangements for transmission loops) Rule 2025 No. 9 (Final Rule).

7 www.projectenergyconnect.com.au.

8 IRSR arises when interconnectors transfer electricity between two regions that have different prices - this is otherwise known as 'price separation'. IRSR is the surplus or deficit arising in settlement when there are different prices in two regions, and energy is flowing between them. Generators in one region are being paid for electricity consumed in another region, at a different price. The resulting IRSR can be positive or negative. AEMO must distribute IRSR to, or recover IRSR from, some party or parties.

9 Due to the physics of electrical circuits, power flows on the arms of a transmission loop are highly interdependent. When there is a constraint somewhere in a transmission loop, the resulting changes in power flows give rise to a pricing pattern called the 'spring washer effect'. The spring washer effect can sometimes lead to efficient counter-price flows, which can be thought of as power flows taking an alternative route around the loop to satisfy the laws of the physics. Refer to appendix C.3.1 of the draft determination for further information about the spring washer effect.

10 The NER do not specify detailed requirements for AEMO's clamping procedures (see NER clauses 3.8.1(b)(11) and 3.8.10(5)). NER clause 3.8.10(c)(5) requires AEMO to set out its approach to clamping in its network constraint formulation guidelines.

AEMO's rule change request proposed to reallocate negative IRSR accruing on looped interconnectors

AEMO's rule change request proposed to reallocate negative IRSR accruing on an arm of a loop in net positive cases to the interconnectors accruing positive IRSR, then recover it from the importing CNSPs for those positive arms. AEMO considered this would align costs with beneficiaries, as the regions accruing positive IRSR would be better placed to pay the negative IRSR. AEMO did not propose any changes to the allocation of positive IRSR or to the SRA arrangements.

To support efficient dispatch, AEMO proposed it would not clamp looped interconnectors to limit negative IRSR when 'net' loop IRSR is positive (i.e., the IRSR allocated to all three arms under the existing arrangements is in total positive).[11] AEMO would, however, clamp the looped interconnectors in net negative cases. The Commission agrees with AEMO's proposed approach to clamping, noting it can be implemented through procedure and guideline changes, and no changes to the NER would be required.

Details of AEMO's rule change request are elaborated in appendix A. The rule change request was submitted after AEMO consulted with industry through its Project Energy Connect Market Integration Papers process.[12] Throughout the rule change process, the AEMC held ongoing bi-lateral meetings with AEMO to better understand the issues raised in this consultation process, and test implementation of the final rule.

1.2.2 Stakeholder consultation helped us to understand the nature of the issue and the range of possible solutions

Our draft rule proposed sharing negative IRSR between all looped regions

In December 2024, the Commission made a draft determination for a more preferable draft rule.[13] We proposed sharing the recovery of negative IRSR for the looped interconnectors between the looped regions, while the status quo arrangements and AEMO's rule change request would recover negative IRSR for each interconnector from the importing region's CNSP.[14] We considered that this approach would more effectively manage the consumer risks of unpredictable negative IRSR compared with the status quo arrangements and AEMO's rule change request.

The draft rule would have maintained the separate treatment of positive and negative IRSR arising under the current allocation methodology, with positive IRSR on an individual arm distributed via the SRA and negative IRSR on an individual arm recovered from CNSPs. The Commission also proposed a future review to consider whether SRA arrangements are providing the best outcomes for consumers and market participants more broadly.

This approach was informed by stakeholder feedback to the consultation paper.[15] This included feedback from Transmission Network Service Providers (TNSPs), who emphasised how cash flow challenges arising from unpredictable negative IRSR could impact customer pricing, and market participants, who considered it was important to maintain the value of SRD units for inter-regional hedging.

11 At the time of writing this final determination, AEMO is consulting on its detailed management of negative settlements residue process for transmission loops. Refer to: AEMO, Consultation on automation of negative residue management for the implementation of transmission loops, aemo.com.au/consultations/current-and-closed-consultations/automation-of-negative-residue-management-for-the-implementation-of-transmission-loops, consultation paper, pp.10-14, and draft report, pp.11-12.

12 This process began in November 2022 and concluded in February 2024, with two formal consultation rounds. Refer to: www.aemo.com.au/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper.

13 AEMC, Inter-regional settlements residue arrangements for transmission loops, Draft rule determination, 12 December 2024.

14 Under AEMO's rule change proposal, when the net loop IRSR is positive, negative IRSR would be re-assigned between the arms of the loop before allocating any amounts to the importing CNSP for an arm. When the net loop IRSR is negative, negative IRSR accruing on any arms would be allocated directly to the importing TNSP as per the current rules.

15 AEMC, Inter-regional settlements residue arrangements for transmission loops, Consultation paper, 8 August 2024.

Our reasons for making the draft rule are included in chapter 2 of the draft determination.[16] In summary, we considered that the draft rule approach would mitigate the risks posed to consumers by large, unpredictable negative IRSR by reducing bill volatility and reducing the maximum potential cost for a customer in any region. We considered this approach would also better align customers' costs with the benefits they receive and help manage cash flow risks for CNSPs.

Feedback from CNSPs and further analysis highlighted the nature of the risk posed to consumers

While most market participants supported the draft rule as a means to maintain the value of SRD units as hedging instruments once the loop commences operation, CNSPs and some consumer groups noted that the draft rule would still result in significant risks, despite the sharing approach.

Stakeholder feedback and our own further analysis, including further analysis of the way that IRSR impacts CNSPs, and is passed through to consumers (as outlined in section 2.4.6), highlighted the nature of the cash flow risks to CNSPs due to negative IRSR. This risk arises even though CNSPs can eventually recover the negative IRSR from customers through transmission prices, because there is a timing mismatch between a CNSP's obligation to pay and their ability to recover negative IRSR from customers. CNSPs need to have sufficient funds available to meet negative IRSR in any weekly billing period. Given the risk of extreme, negative IRSR, this would be particularly costly.[17] We determined that similar or greater risks to consumers and CNSPs would also arise if the existing IRSR arrangements were applied to transmission loops, or if AEMO's reallocation method proposed in its rule change request were implemented.

We also further considered how the introduction of a new loop in the NEM changes how negative IRSR arises and the impacts of this on consumers. Larger and more frequent negative IRSR allocated to individual arms of the loop will be unavoidable due to the physics of the loop (and AEMO's planned approach to clamping). Stakeholder feedback led us to revisit a range of potential options for addressing the issue raised in the rule change request, and consider which of these options would allocate IRSR around the loop in a way that is more likely to better contribute to the achievement of the NEO.[18]

We released a directions paper that proposed a revised policy direction: to net off IRSR in transmission loops

In June 2025, we released a directions paper and indicative rule drafting that sought stakeholder feedback on a 'netting off' approach for allocating positive and negative IRSR in transmission loops.[19]

The proposal in the directions paper was informed by our re-consideration of options and initial analysis that, of those options, a netting off approach was likely to be beneficial to consumers. The other options we considered included those raised by the rule change proponent, stakeholders and other options we developed.[20]

The feedback we considered in developing the proposal in the directions paper was gathered through several avenues:

- the submissions to the draft determination

16 Refer to chapter 2 of the draft determination, p. 5.

17 Refer to section 2.3.2 of the directions paper, p.15, for further information on the nature of the risk to CNSPs, and, ultimately, consumers.

18 Refer to section 2.1 of the directions paper, p.11, for further information on how IRSR behaves differently in transmission loops.

19 AEMC, Inter-regional settlements residue arrangements for transmission loops, Directions paper, 19 June 2025.

20 Refer to section 2.4.6 of this final determination and section 2.5 of the directions paper, p.10, for our analysis of options.

- bi-lateral engagement with stakeholders to understand and gather further analysis and evidence of the issues raised in those submissions
- a technical working group session held in April 2025 to explore the netting off option and feedback received from stakeholders following that workshop. The materials from this session were published on the AEMC's website here, and we invited stakeholder feedback on the material.

Under the proposed netting off approach in the directions paper:

- when loop IRSR is net positive, negative IRSR arising on an arm of the loop under the current allocation methodology would be deducted from the positive IRSR that arises on the other arm(s). This would be in proportion to the size of the positive IRSR on each arm. This netted IRSR would then be distributed to SRD unit holders.
- when loop IRSR is net negative, any positive IRSR arising on any arm under the current allocation methodology would be used to reduce negative IRSR in that trading interval, and the remaining negative IRSR would be recovered from CNSPs, who would in turn recover it from consumers via transmission pricing.

Our reasons for proposing this are included in chapter 2 of the directions paper.[21]

In summary, we considered that market participants have appropriate expertise and tools at their disposal to manage inter-regional price risk. The IRSR distributed through SRD units is one tool to manage this risk, but different types of contracts and hedging products are also available. We consider that market participants can continue to use netted-off SRD units as part of inter-regional hedging strategies because the proposed design would make all net positive IRSR in the transmission loop available to the market. That is, the net loop IRSR is the amount that market participants (the typical buyers of SRD units) require to collectively manage their inter-regional price risk in any trading interval. We analysed test cases to come to this view in the directions paper, and included a worked example of how two market participants could manage their inter-regional price risk under the directions paper approach in appendix A.[22]

Market participants were concerned about the impacts of netting on inter-regional hedging

In response to the directions paper, retailers, generators and associated industry bodies (referred to collectively as 'market participants' in this determination) strongly opposed netting off, while CNSPs and consumer groups supported it. We offered further targeted, bilateral meetings over the months before (and after) submissions to the directions paper closed to better understand market participants' concerns.

In particular, we understand market participants considered that netting off SRD units would make these less effective hedging instruments, which would ultimately increase costs for consumers through higher hedging costs and decreased retail competition.

Some market participants provided detailed examples that demonstrated how these instruments were used to hedge inter-regional price risks, in response to the example we provided in appendix A of the directions paper. These participants criticised the example as being 'stylised' and not representative of participants' hedging strategies. This prompted us to reconsider the netting design for the final rule, as elaborated below and in section 2.4.5 and section 3.1.2. Several market participants also raised concerns that netting may impact liquidity in risk management markets. Our response to this is also elaborated below and in section 2.4.5.

21 Refer to chapter 2 of the directions paper, p.10.

22 Refer to appendix A of the directions paper, p.56.

Our detailed analysis and response to market participants' feedback, and how it has informed this final determination, is set out in chapter 3 and chapter 4 of this final determination.

1.2.3 We have maintained a netting approach for the final determination but chosen a different design after considering stakeholder feedback and further analysis

After considering stakeholder feedback in detail, and conducting our own further analysis, the Commission has decided to maintain a netting approach for the final rule, but pursued changes to the netting design. The final rule is likely to better contribute to the achievement of the NEO than the proposal in the rule change request as it better manages the risks to consumers and lowers costs to consumers by allocating IRSR efficiently. Our detailed reasoning is set out in chapter 3.

We consider the final rule netting design is likely to enable more efficient hedging of inter-regional price risks than the netting design proposed in the directions paper because it better reflects the underlying flows of electricity between the looped regions, than the approach proposed in the directions paper. This is likely to promote inter-regional trade as it reduces the costs of, and increases the effectiveness of, SRD units in managing inter-regional price risks. Chapter 4 sets out the netting design and our reasoning for this conclusion in more detail.

We have come to our decision with the information available to us at this time

We understand that there are risks with introducing a netting off approach for IRSR in transmission loops. There has never been a transmission loop in the NEM and we cannot be sure of IRSR outcomes around the loop until it is in operation, as we do not have operational data or experience to work with. We have used the data and analysis we have available, alongside economic theory and information provided by stakeholders,[23] to make our decision. We consider that market participants remain the best party to manage negative IRSR in a loop, at a lower cost than the rule change proposal and other approaches.

Market participants considered that netting may contradict the NEM Expert Panel's aims to improve market liquidity as it could make SRD units less effective hedging instruments.[24] They also considered that netting may impact retail competition in SA where there is already low liquidity. For generators outside of SA to sell a contract linked to the SA price, they ideally need well-designed inter-regional hedging instruments (which include SRD units) to manage inter-regional pricing risk. Stakeholders are concerned that netting undermines the effectiveness of the SRD units for hedging inter-regional pricing risk, and hence liquidity in SA.

We consider that contract market liquidity is important to good consumer outcomes, and that well-designed SRD units are important in this regard. However, we consider that the impact of netting on contract market liquidity and retail competition is likely to be less significant than some of the potential outcomes referred to in submissions. Although well-designed SRD units are one important component, competition and liquidity are influenced by many factors and market processes, including in SA. We have designed the net trade approach to netting to best enable market participants to manage inter-regional price risk in the new context of the loop.

23 This includes the analysis set out in the draft determination, directions paper and this final determination and its appendices, as well as analysis conducted by ACIL Allen in its paper 'Modelling the settlement effects of Project Energy Connect', July 2023. This is available at: https://www.aemo.com.au/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper.

24 The NEM Expert Panel is currently conducting a review into the wholesale market, and released a draft report in August. Refer to Nelson, et.al., National Electricity Market wholesale market settings review, Draft Report, August 2025, available at https://consult.dcceew.gov.au/nem-review-draft-report-consultation#consultation-documents.

There will be a learning period as industry adapts to new loop operation

We heard from market participants that negative IRSR will be difficult for them to manage, which they consider will increase costs to consumers and may impact market liquidity. However, we consider that these difficulties mostly arise as a result of loop operation, which will benefit consumers in connected regions through more efficient inter-regional capacity transfer, rather than due to the netting off approach. As explored in detail in chapter 2 of this final determination, netting is the approach that best manages the risks to consumers and lowers costs to consumers by allocating IRSR efficiently.

Nonetheless, we acknowledge that this final rule comes with risks and uncertainties, and there will be a learning period as industry adapts to new loop operation. We have made efforts in this final rule to make information available to market participants so they can make informed hedging decisions, including through the reporting and transitional arrangements outlined in chapter 3 and chapter 4 of this final determination and the detailed examples in appendix B. There will be 12 months before PEC becomes operational for AEMO to implement the rule and any changes to the auction rules and other guidelines, and for CNSPs and market participants to understand the new arrangements.

The Commission encourages industry bodies to support market participants as they seek to better understand loop operation and the netting approach in the final rule. This may include paper trials that build on the examples in appendix B and further information released by AEMO as it updates relevant documentation when implementing the rule.

1.3 The final rule will assist with the immediate issues related to the loop, but there is a case to review arrangements more holistically

The final rule puts in place new arrangements for IRSR in transmission loops. These are needed prior to the introduction of the loop to provide certainty to the market, CNSPs and AEMO, and to ensure the benefits of the loop to consumers can be realised as soon as possible.

1.3.1 A review could examine the SRA and the IRSR framework in the context of broader market considerations and directions

We are in the midst of transitioning to a low emissions electricity system and this rule change has been made in the context of a changing market with associated uncertainties. Other broader market reforms are also being progressed that should be accounted for in a future review.

In particular, the NEM Expert Panel Draft Report highlights that:[25]

> Interconnectors are critical to delivering the full benefits of the NEM, particularly as more weather-dependent generation connects. Their importance will continue to grow as interconnectors link regions with diverse weather patterns.

It recommends:

> 9D: The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.

25 Nelson, et.al., National Electricity Market wholesale market settings review, Draft Report, August 2025, p.195.

We agree with the Draft Report's characterisation of the importance of interconnection in a future NEM and support the recommendation that the AEMC conducts a future review.[26]

1.3.2 We intend to conduct a future review of the SRA and the IRSR framework, after at least one year of loop operation

We intend to conduct a future review of the SRA and the IRSR framework for both radial and looped interconnectors. A review would provide the opportunity to consider holistically the IRSR and SRA arrangements across both radial and looped interconnectors, and consider changes that would promote liquidity, make it a more effective inter-regional hedging instrument, and so promote the interests of consumers. This would also action the recommendation of the NEM Expert Panel for a review (if adopted by the Australian Government), and could explore options to promote longer-term contracting across regions in conjunction with reforms to existing interconnector hedging arrangements.

Stakeholder views and our own analysis throughout this rule change process have highlighted that there is merit in reviewing how IRSR is distributed through SRD units to determine whether the arrangements meet the needs of consumers in both the current and future NEM. In particular, we have identified a difference between the SRA proceeds paid to consumers versus SRD unit payouts received by unit holders, which has been persistent across time and regions in the NEM. There may be a number of explanations for this, which warrant further investigation once the loop is operating. This is explored in further detail in chapter 5.

As we cannot be sure of IRSR outcomes around the loop until it is in operation, we consider a review would be most valuable after at least one year of data from PEC's operation is available. As discussed in chapter 5, stakeholders were generally supportive of a broad review that covered some or all of the elements identified above, with most advocating for this to be after there was operational experience with the loop.

26 The AEMC's submission to the NEM Expert Panel Review Draft Report is published on our website: AEMC, submission to national electricity market settings review draft report, 17 September 2025, available at: www.aemc.gov.au/market-reviews-advice/future-wholesale-market. We discuss specific items relating to the SRA and IRSR arrangements on p.30 of our submission.

2 The rule will contribute to the energy objectives

The final rule will promote the NEO by netting off IRSR in transmission loops, which we consider will deliver outcomes in the long-term interests of consumers and support efficient risk management. The final rule will also share net negative IRSR by regional demand. This approach allocates costs and risks appropriately and promotes stable, predictable outcomes. In addition, the final rule includes transitional arrangements and reporting requirements that will support transparency in loop arrangements and IRSR outcomes. We consider the final rule better promotes the NEO than the rule change request. The Commission was not satisfied that options that did not involve netting would adequately manage risks and costs for consumers.

The rest of this chapter outlines how the final rule will contribute to the achievement of the NEO, why we made a more preferable final rule, and how the final rule meets our assessment criteria. How the final rule will operate, and further reasoning for this final determination, is discussed in chapter 3 and chapter 4.

2.1 The Commission must act in the long-term interests of energy consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[27]

For this rule change, the relevant energy objective is the NEO.

The NEO is:[28]

> 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; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[29]

2.2 We must also take these factors into account

2.2.1 We have considered whether to make a more preferable rule

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.[30]

27 Section 88(1) of the NEL.

28 Section 7 of the NEL.

29 Section 32A(5) of the NEL.

30 Section 91A of the NEL.

For this rule change, the Commission has made a more preferable final rule. The reasons are set out in section 2.4 below.

2.2.2 We have considered how the rule will apply in the Northern Territory

In developing the final rule, the Commission has considered how it should apply to the Northern Territory according to the following questions:

- **Should the NEO test include the Northern Territory electricity systems?** Yes. The Commission considers that the NEO test should include the Northern Territory electricity systems given that parts of the final rule would apply in the Northern Territory (even though it will have no operative effect).
- **Should the rule be different in the Northern Territory?** No. The Commission has determined that a uniform rule should apply to the Northern Territory. This is consistent with the draft determination. However, the final rule will have no operative effect in the Northern Territory since chapters 3 and 6A of the NER do not apply in the Northern Territory. While other parts of the final rule will apply in the Northern Territory (i.e. chapters 10 and 11 of the NER), these will have no operative effect without the other parts of the rule that relate to chapters of the NER that do not apply (i.e. chapters 3 and 6A). Therefore, the Commission considers that a uniform rule would be a suitable solution. The Commission's final determination is to make a uniform rule so that while parts of the final rule will apply, they will have no operative effect in the Northern Territory.

See appendix D for more detail on the legal requirements for our decision.

2.3 How we have applied the legal framework to our decision

The Commission must consider how to allocate IRSR in transmission loops against the legal framework.

We identified the following criteria to assess whether the proposed rule change, no change to the rules (business-as-usual), or other viable, rule-based options are likely to better contribute to achieving the NEO:

- **Outcomes for consumers:** The design of the arrangements to manage and allocate IRSR in a transmission loop will affect the distribution of costs to consumers in different regions. The introduction of the transmission loop will affect market outcomes (including dispatch, imports and exports, prices, and positive and negative IRSR) in complex ways due to the interdependent nature of loop flows and how this interacts with the NEM's regional pricing model. Under this criterion, we have considered how the rule change would affect outcomes for consumers and which approach for managing and allocating IRSR is in the best interests of consumers.
- **Principles of market efficiency:** Principles of efficiency are relevant because the market arrangements for transmission loops will affect the extent to which some of the benefits of PEC (and the other looped interconnectors) are realised and flow through to consumers. Under this criterion, we have considered questions relating to concepts of efficiency and risk allocation. Specifically, we have considered:
  - how to allocate settlements residue in the most efficient way to ensure that risks and costs are managed for consumers,
  - the role of SRD units in realising the inter-regional trade benefits of the loop,

    - how clamping arrangements will influence loop flows and hence the consumer benefits of PEC.
- **Principles of good regulatory practice:** It is important to create clear, stable, and predictable market arrangements for allocation of settlements residue and inter-regional trading, so that the incentives for market participants and investors lead to efficient outcomes. Under this criterion, we have considered whether the rule change will promote predictable and stable outcomes for consumers, and how to balance certain and uncertain outcomes.

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request, for impacts within the scope of the NEO. These assessment criteria are the same as those we proposed in the consultation paper and used in the draft determination. Section 4.2 of the consultation paper sets out our reasons for choosing these criteria. The Commission has responded to stakeholder feedback on the assessment criteria in section 2.3.1 of the draft determination.

The Commission has undertaken regulatory impact analysis to evaluate the impacts of the various policy options against the assessment criteria. This analysis is outlined throughout this chapter, chapter 3 and chapter 4.

2.4 Why we consider netting off better promotes the NEO

This section explains why the final rule is likely to better contribute to the achievement of the NEO compared to the rule change proposal when evaluated against our assessment criteria. It also explains why the Commission was not satisfied that the options that did not involve netting would adequately manage risks and costs for consumers. The Commission expects that the final rule will promote the NEO by:

- netting off IRSR in transmission loops, which supports efficient risk management and delivers outcomes in the long-term interests of consumers
- sharing net negative IRSR by regional demand, which allocates costs and risks appropriately and promotes stable, predictable outcomes
- putting in place comprehensive reporting and transitional arrangements that support transparency and predictability.

In making this final determination, the Commission has had to weigh the different options for managing IRSR in transmission loops without real-world data about the operation of the loop. We have considered the potential impacts of each option on consumers, taking into account divergent stakeholder views, to make our decision. As discussed in chapter 5, we are also recommending a future review, which would consider IRSR and SRA arrangements more broadly with the benefit of operational experience.

In this section:

- Section 2.4.1 summarises why we consider a more preferable rule is needed to address the problem in this rule change.
- Section 2.4.2, section 2.4.3 and section 2.4.4 set out our rationale for the final rule based on our assessment criteria - outcomes for consumers, principles of market efficiency, and principles of good regulatory practice - including the reasons why we have made changes from the directions paper proposal.
- Section 2.4.6 sets out our assessment of the rule change proposal as well as other options we considered.

2.4.1 The Commission has made a more preferable rule to address the problem we have identified

This rule change considers how to allocate IRSR in a transmission loop

In this rule change process, we are considering how to manage financial flows given that transmission loop operation changes the physical flows of electricity. AEMO first raised the question of how to allocate IRSR in transmission loops in its rule change request and noted that IRSR behaves differently in transmission loops.[31] As outlined below, large and unpredictable negative (and positive) IRSR will be an unavoidable outcome of the transmission loop. There are multiple possible approaches to allocating and managing this IRSR, but the IRSR amounts, and the costs of managing the associated risks, will always flow through to consumers.[32] However, different parties have different tools available to manage them, and face different risks and costs as a result. In this rule change we have sought to manage the costs and risks in the way that is best for consumers in the long term.

We consider that applying the existing arrangements to a transmission loop would lead to significant risks and costs for consumers. Unclamped negative IRSR on individual arms of the loop could be large and unpredictable. If this negative IRSR was recovered from CNSPs, consumers would be exposed to this risk via transmission prices and the costs for CNSPs to manage the associated cash flow risk (refer to section 2.4.6 for more information).

AEMO proposed to reallocate negative IRSR to arms of the loop that are accruing positive IRSR in the same trading interval, and recover it from the importing CNSPs for those arms. AEMO considered this would prevent an “unfair” wealth transfer between consumers in different regions.[33] However, we consider that this approach would also pose significant risks to consumers by allocating all negative IRSR to CNSPs.

The Commission considers that the final rule for netting off IRSR in transmission loops is likely to better contribute to the achievement of the NEO than the rule change proposal. Our analysis of the rule change proposal, and the other options we considered that did not involve netting, is set out in section 2.4.6.

Box 1: IRSR behaves differently in transmission loops

IRSR arises in the NEM due to price separation between regions. The NEM consists of five regions, each with its own regional reference price (RRP) (see note 1). IRSR is the surplus or deficit arising in settlement when interconnectors transfer electricity between two regions that have a price separation (that is, different RRPs). AEMO – which settles all market customers and generators – must allocate IRSR to, or recover IRSR from, some party or parties.

Positive IRSR arises when electricity flows along an interconnector from a lower-priced to a higher-priced region. In this case, market customers are paying more than generators are being paid for the electricity transferred between regions, so the market has a shortfall while settlement is in surplus. Conversely, a counter-price flow from a higher-priced to a lower-priced region gives rise to negative IRSR, which represents a market surplus and settlement shortfall.

Under the current arrangements, positive IRSR is auctioned in the form of SRD units which help enable market participants to hedge inter-regional price risk (refer to section 2.2 of the directions paper, pp.12-14). SRD units can function as effective hedging units because inter-regional price

31 Refer to AEMO’s rule change request, pp.8-9.

32 The actual IRSR amounts would not be changed by any of the options we considered except for additional clamping or a micro-slice implementation of PEC, which are undesirable for the reasons discussed in section 2.4.6.

33 Refer to AEMO’s rule change request, p.9.

risk depends on price separation, which is directly related to IRSR - and because the SRA returns any settlement surplus to the market. The SRA framework also benefits consumers by supporting inter-regional trade, as well as allowing consumers to exchange a volatile cash flow (positive IRSR) for a stable and predictable one (SRA proceeds). Negative IRSR is currently allocated to CNSPs and recovered from consumers via transmission prices.

PEC, along with the existing interconnectors between NSW, Victoria and SA, will create the first inter-regional transmission loop in the NEM. Power flows, prices and IRSR in the transmission loop will be determined by the physics of electrical circuits (Kirchhoff's laws) and how this interacts with the NEM's regional prices. In a transmission loop, counter-price flows between regions can occur as a normal part of efficient dispatch due to the spring washer effect. (For a detailed explanation of the spring washer effect, refer to Box 8 in the draft determination, p.54.) Therefore, larger and more frequent negative IRSR, and even larger positive IRSR is likely to arise on individual arms of the loop. This is an inherently different situation to radial interconnectors.

Generally, the PEC transmission loop will operate as a whole to transfer electricity from lower-priced regions to higher-priced regions, broadly consistent with efficient dispatch. When this occurs, the net IRSR for the loop is positive - that is, settlement is in surplus in the loop. The net IRSR for a transmission loop can also be negative, in which case there is a settlement shortfall in the loop and market participants are collectively paid more than is needed to cover the cost of generation. Net negative IRSR in a transmission loop would typically occur when dispatch is strongly influenced by intra-regional constraints - analogous to negative IRSR on a radial interconnector (see note 2).

Modelling undertaken by ACIL Allen for AEMO suggests that negative IRSR will arise frequently on one or two arms of the loop while the net loop IRSR is positive. Negative IRSR is difficult to forecast accurately, and further modelling is likely to have limited value as it would be based on many simplifying assumptions. However, we have found that in certain extreme circumstances, negative IRSR on one arm of the loop could potentially reach $100 million in one week. (See Box 3 in the draft determination, p.20, for an example demonstrating this.)

Negative IRSR on individual arms of the loop will not be clamped when the net loop IRSR is positive. Although negative IRSR on radial interconnectors is managed by clamping, it would not be appropriate to use the same approach for the transmission loop. AEMO has stated it will only clamp the looped interconnectors when the net loop IRSR is negative. Clamping the loop in net positive cases would interfere with efficient dispatch and prevent the benefits of PEC from being realised. The Commission agrees with AEMO's proposed clamping approach.

Source: ACIL Allen, Modelling the settlement effects of PEC, July 2023, pp.i-ii.

Source: AEMO, Consultation on automation of negative residue management for the implementation of transmission loops, consultation paper, June 2025, pp.10-11.

Note: 1. The NEM regions are Queensland, NSW (comprising the ACT), Victoria, South Australia and Tasmania. All wholesale market participants in a region transact at that region's RRP. Each market participant transacts at its RRP multiplied by a marginal loss factor which depends on market participants' or their customers' specific locations within a region.

Note: 2. Intra-regional constraints can create incentives for disorderly bidding, which further influences dispatch and leads to inefficient outcomes. For this reason, negative net loop IRSR is likely to be inefficient, whereas negative IRSR on one or two arms in net positive cases is more likely to be efficient.

2.4.2 The final rule promotes improved outcomes for consumers

The final rule promotes improved outcomes for consumers by managing the risk of negative IRSR while keeping costs low, and distributing the costs appropriately between consumers in different regions.

Netting off will manage the risks of negative IRSR at the lowest cost to consumers

The Commission considers that netting off based on net trade is likely to produce better consumer outcomes than the rule change proposal because it supports efficient risk management. This approach allocates IRSR efficiently and continues to support inter-regional hedging, as discussed in section 2.4.3. Efficient risk management lowers costs to consumers because it enables IRSR and the risks associated with it to be managed effectively at lowest cost. Netting off addresses the cash flow risks and costs to CNSPs and flow-on impacts on consumers. We consider that other options for allocating IRSR in transmission loops (discussed in section 2.4.6) would result in higher costs to consumers than netting because they would not allocate IRSR to the party best placed to manage it.

Sharing net negative IRSR amongst CNSPs by regional demand will allocate costs and risks appropriately

When the net loop IRSR is negative, the final rule will allocate the net negative IRSR to CNSPs to be recovered from consumers. This helps enable SRD units to support efficient risk management, as discussed in section 2.4.3. Refer to section 3.2.2 for more information on netting off in net negative cases, including our consideration of the stakeholder feedback on this issue.

The final rule will share net negative IRSR between the CNSPs in the looped regions in proportion to regional demand. This approach aligns costs with benefits by distributing net negative IRSR amongst all consumers in the looped regions in proportion to their energy usage. It also further mitigates risks by spreading potential volatility in net negative IRSR amongst the three regions. CNSPs and consumer groups were supportive of this approach in their submissions to the directions paper.[34] Where market participants commented on this aspect of the proposal, they also supported it in principle.[35] Refer to section 3.3 for more information on allocation by regional demand, including detailed stakeholder feedback and our response.

2.4.3 The final rule aligns with principles of market efficiency by promoting efficient risk management

Netting based on net trade is the solution that best aligns with principles of market efficiency because it allocates IRSR efficiently and continues to support inter-regional hedging. Effective inter-regional hedging enables inter-regional trade, which is beneficial to consumers because:

- it supports retail competition between retailers by supporting retailers and gentailers to serve load across multiple regions, which provides more choice for consumers and helps keep costs low
- it allows the market to provide investment signals for generation, storage and load to be located efficiently across different regions.

Allocating all IRSR to market participants in net positive cases supports efficient risk management

Market participants are best placed to manage both positive and negative IRSR

Market participants are best placed to manage all IRSR in a transmission loop when IRSR is net positive, because:

- this aligns the party managing the price separation risk with the party managing the resulting IRSR,
- they have the tools and expertise to manage the IRSR and associated risks, and
- the positive IRSR more than offsets the negative IRSR when the loop is net positive, meaning that debt facilities are not required to cover potentially extreme negative IRSR.

34 Submissions to the directions paper: Energy Networks Australia (ENA), p.1; Transgrid, p.3; Energy Consumers Australia (ECA), pp.1-2; Energy Users Association of Australia (EUAA), p.2.

35 Submissions to the directions paper: Stanwell, p.2; Shell Energy, p.3.

A key role of market participants in the NEM is to manage market risk on behalf of consumers. This includes managing inter-regional price risk when participants choose to operate across multiple NEM regions. Both inter-regional price risk and IRSR arise from price separation between NEM regions. Therefore, it is appropriate that the same party manages both inter-regional price risk and all IRSR, at least when net loop IRSR is positive.

Market participants have a range of options available to them to manage market risks including inter-regional price risk. Some market participants consider there are limited tools available for inter-regional hedging and that the primary alternative to SRD units is swap and cap contracts in-region. However, we consider they have options including in what contracts they enter into (standard ASX contracts or otherwise), how they use SRD units, how they build their generation and load portfolios, and the pricing structures they offer to customers. Market participants are incentivised to manage their risk in the most efficient way to offer competitive prices to consumers, and have a range of risk management options available to do so.

For these reasons, we consider market participants are better placed to manage this net positive IRSR than CNSPs, AEMO, or market customers.[36] The Commission notes stakeholders' comments that CNSPs may be well placed to manage negative IRSR, as large monopoly businesses with regulated returns.[37] However, as economically regulated businesses, CNSPs can only raise funds and recover costs in specific ways, generally do not participate in the hedging market, and are prohibited from participating in the SRA.[38] We discuss the impacts of cash flow risk on CNSPs in more detail in section 2.4.6.

Further to this, netting off will not expose market participants to an extreme negative cash flow risk of the type that CNSPs (or other parties) would face if there was no netting and they were required to manage the negative IRSR. This is because the final rule is designed such that SRD units never pay out negative amounts. Therefore, we do not expect that market participants will need to maintain debt facilities to fund potentially extreme negative IRSR. Rather, netting off will change the characteristics of one of the hedging instruments (SRD units) that participants use. Market participants will then (as now) be able to bid at what they consider is fair value for the netted SRD units and decide how to use these units as part of an overall hedging strategy.

Netting based on net trade will support inter-regional hedging in the transmission loop

The net trade approach in the final rule is designed to provide SRD units that enable effective inter-regional hedging in the transmission loop.

We expect that the creation of a transmission loop will trigger significant changes to market participants' inter-regional hedging strategies, regardless of this rule change, because IRSR will behave differently in a loop. The introduction of PEC will radically alter the physical flow of electricity on individual arms of the loop compared to current flows. Consistent with Kirchhoff's circuit laws, power flows must take all available paths from generation to load, including both the most direct route and the 'long way around' via the third region. Under the existing arrangements, or the netting approach proposed in the directions paper, SRD unit payouts would be based on these physical flows.

Under the final rule, SRD unit payouts are not based on the physical flows. Instead, all net positive IRSR in the transmission loop is made available for inter-regional hedging through the SRA. The

36 AEMO would manage the cash flow risk associated with negative IRSR under the AEMO holding fund option that we considered; market customers (including but not limited to retailers) would manage it under the option of recovering negative IRSR from market customers. See section 2.4.6.

37 Submissions to the directions paper: AGL, p.3; Alinta Energy, p.6; Australian Energy Council (AEC), pp.3-4.

38 Clause 3.18.2(g) of the NER.

net loop IRSR is the amount that market participants (the typical buyers of SRD units) require to collectively manage their inter-regional price risk in any trading interval. This is because the net loop IRSR is the amount paid by load in the looped regions less the amount paid to generators in the looped regions, so it is equal to the overall market shortfall for the loop. Of course, individual market participants may not have acquired exactly the right combination of SRD units given their physical and other contractual positions, but in principle, it is possible for all market participants to hedge their risk.

Applying the existing arrangements to the transmission loop would result in more than the total (net positive) IRSR being allocated to SRD unit holders, with the shortfall recovered from consumers via CNSPs. In this case, the market may receive more than it strictly needs to hedge its downside risk associated with price separation - or in other words, the market is collectively exposed to an upside risk. Upside risk is less problematic for individual participants, and allocating more than the net positive IRSR to the market may help compensate for the challenges of hedging inter-regional price risk in a complex market, especially given SRD units are not firm. However, the net positive IRSR is sufficient for the market collectively to hedge its inter-regional price risk, and we consider that market participants are in a position to manage these complexities on behalf of consumers more efficiently than CNSPs,[39] AEMO or market customers can.

The proportional netting approach that we proposed in the directions paper also would have allocated all net positive IRSR to SRD unit holders. However, the Commission considers that netting based on net trade is likely to support inter-regional hedging more effectively than proportional netting. Under the net trade approach, SRD unit payouts will be based on the net energy transfers between each pair of regions, rather than the physical flows on each interconnector. We consider that these net trade amounts will better reflect the inter-regional price separation exposures that participants wish to hedge. The benefits of the net trade approach compared to proportional netting are discussed further in section 3.1.2. Net trade would apply in all net positive cases, including when there is positive IRSR on all three arms of the loop.

Allocating clamped net negative IRSR to CNSPs helps manage risks for all parties

When the net loop IRSR is negative, the final rule will allocate the net negative IRSR to CNSPs to be recovered from consumers. That is, if the net loop IRSR is negative in a trading interval, positive IRSR on any arm(s) of the loop will be used to reduce negative IRSR instead of being distributed to SRD unit holders. However, the residual net negative amount will be recovered from CNSPs (in proportion to regional demand, see section 2.4.2 and section 2.4.4), and not from SRD unit holders. This ensures that no SRD units are allocated a negative dollar amount in any trading interval, or over time. This avoids the need for a complex redesign of the SRA which would be required to allow the clearing price to be negative to account for potential negative payouts. It also avoids changes to prudential requirements which would likely be needed if SRD unit holders were potentially liable for payments of IRSR to AEMO.

Given that the final rule implements netting in net positive cases, we consider this approach best manages the risks for CNSPs, market participants, and hence for consumers, because:

- clamping will limit the overall magnitude of negative IRSR in net negative cases
- since negative IRSR can still be material despite clamping, netting off helps manage the risk to CNSPs and consumers

39 Indeed, TNSPs are not permitted to participate in the SRA. See clause 3.18.2(g)(2) of the NER. As economically regulated entities, TNSPs can only pass the cost on to consumers and cannot otherwise hedge or reduce it.

- it avoids negative SRD unit payouts, which supports SRD units to continue functioning as effective hedging instruments.

2.4.4 The final rule is consistent with good regulatory practice

The final rule netting approach is consistent with good regulatory practice as it prioritises predictable signals to the market.

Transitional arrangements and reporting will increase predictability and transparency

The final rule includes transitional arrangements to promote certainty and transparency. In particular, it clarifies key dates for implementation of the loop in dispatch and the settlement arrangements over the loop transition period, as well as requiring AEMO to use reasonable endeavours to auction new NSW-SA and SA-NSW units by quarter (Q) 3 2026. AEMO must also publish information relevant to the loop transition as soon as practicable, and keep this information up to date. Refer to chapter 4 for more information.

The final rule includes expanded reporting requirements to support predictability and transparency. AEMO will be required to publish additional information on IRSR and SRA outcomes, including information regarding unit termination and secondary trading, and IRSR and net trade outcomes at a trading interval resolution. This data will help market participants understand how the loop arrangements impact power flows, prices, IRSR, unit payouts, and auction dynamics, and hence make better hedging decisions. It will also assist CNSPs in forecasting IRSR-related cash flows and managing these cash flows throughout the year. Refer to section 3.4 for more information. The rule change proposal did not propose any transitional or reporting arrangements. We therefore consider the final rule is likely to better contribute to the achievement of the NEO than the proposal.

Together, the reporting and transitional arrangements will allow:

- AEMO to implement the new arrangements in its settlement systems, and consult on and update relevant procedures and methodologies in time for PEC's commencement in October 2026.
- Market participants to prepare for how the operation of the loop will impact their bidding and hedging strategies.
- CNSPs to understand the cash flow implications of the transmission loop and final rule, and take this into account in setting transmission prices for the 2026-27 financial year to the extent possible.

There will be a learning period while market participants and CNSPs adjust to the operation of the loop. We acknowledge the final rule netting approach is complex and substantially different to the existing arrangements and may contribute to uncertainty in this adjustment period. Information provision arrangements in the final rule are intended to help market participants and CNSPs make informed decisions in the face of this uncertainty (refer to the reporting arrangements in section 3.4 and the transitional arrangements in chapter 4).

The allocation of net negative IRSR by regional demand will provide stable outcomes

We have considered predictability and stability in determining how net negative IRSR is allocated amongst CNSPs in the final rule. The final rule shares net negative IRSR in proportion to regional demand, which reduces volatility for any given CNSP and its customers. We have maintained the 52-week rolling calculation of regional demand because it balances stable outcomes with accuracy and ease of implementation. Refer to section 3.3.2 for more information.

2.4.5 We have considered stakeholder feedback on netting in making the final rule

Stakeholders expressed diverse views on netting in submissions to the consultation paper. CNSPs and consumers groups were generally supportive of netting, while market participants strongly opposed it. This section summarises the high-level feedback we received about netting and our responses. Feedback on the detailed design of netting is discussed in chapter 3.

The Commission acknowledges market participants' concerns that netting may create challenges for inter-regional hedging, with resulting potential impacts on retail prices and competition. We have weighed these risks against the risks associated with recovering all negative IRSR from consumers via CNSPs (as would be the case under AEMO's rule change proposal, the existing arrangements, or the draft rule), as well as other options as discussed in section 2.4.6. We consider that netting based on net trade is likely to better contribute to the achievement of the NEO than the rule change proposal. We are also not satisfied that the other options that did not involve netting adequately manage risks and costs for consumers. In making this determination, we are also aware that uncertainty remains regarding exactly how the transmission loop will impact market outcomes and how participants will respond.

CNSPs and consumer groups supported netting

In submissions to the directions paper, CNSPs and consumer groups supported the Commission's netting off proposal.[40] Transgrid considered that netting off would "substantially reduce CNSP exposure to large and volatile cashflow risk compared to the draft determination" while also reducing transmission prices for consumers.[41] Energy Networks Australia (ENA) similarly considered the proposed approach would reduce risks to CNSPs and consumers, and was "practical to implement".[42] Energy Consumers Australia (ECA) considered that netting off would result in "material benefits for consumers" and the EUAA noted it would allocate costs and risks to those best able to manage them.[43]

Market participants raised strong concerns with netting

Submissions to the directions paper indicated that market participants - including retailers, generators, gentailers, traders and associated industry bodies - were strongly opposed to the netting off approach.[44] Market participants' key concern was that netting off would make SRD units less effective for hedging inter-regional price risk (that is, reduce the hedging value or firmness of the units) because it would reduce the correlation between price separation (and/or power flows) and SRD unit payouts.[45] Market participants emphasised the importance of SRD units for hedging inter-regional price risk and their role in supporting retail competition.[46] Some stakeholders disagreed with the Commission's argument that market participants were best placed to manage IRSR in the transmission loop (in net positive cases), in part because of the hedging challenges that they expected would result from netting.[47] Market participants considered that a decision to implement a netting approach did not properly take into account the consumer benefits of the SRA in supporting competition, and that the costs to participants of managing netted IRSR would likely be greater than the avoided risk.[48] Participants considered that reducing

40 Submissions to the directions paper: ECA, p.1; EUAA, pp.1-2; ENA, p.3; Transgrid, p.1.

41 Transgrid, submission to the directions paper, p.3.

42 ENA, submission to the directions paper, p.3.

43 Submissions to the directions paper: ECA, p.1; EUAA, p.2.

44 Submissions to the directions paper: Delta, p.1; Snowy Hydro, p.1; ENGIE, p.1; Shell Energy, p.1; Origin, p.1; AGL, p.1; EnergyAustralia, pp.1-4; Alinta Energy, p.1; Stanwell, p.2; AEC, p.1; Australian Financial Markets Association (AFMA), p.1.

45 Submissions to the directions paper: Origin, p.3; AFMA, pp.1-2; Alinta Energy, p.3; Snowy Hydro, p.2; ENGIE, p.2; AEC, p.1; Stanwell, p.2.

46 Alinta Energy, p.3; Origin, pp.1, 3; AFMA, pp.1-2, ENGIE, p.2; Stanwell, p.2; AGL, p.1; Alinta Energy letter - received 9 September 2025, pp.2-3.

47 Submissions to the directions paper: Origin, pp.7-8; Alinta Energy, p.6; AEC, p.2; AGL, pp.1,3.

the usefulness of SRD units would reduce their ability to manage risks and force them to change their hedging strategies, which would ultimately reduce the efficiency of inter-regional trade and result in higher prices for consumers and reduced retail competition.[49] They noted that netting off does not remove the direct cost of negative IRSR, which will instead flow to the market and eventually to consumers.[50] Stakeholders suggested that costs for consumers could be increased by several different mechanisms, including those set out below.

Stakeholders consider that netting would increase demand for swap and cap contracts

Market participants use SRD units to hedge inter-regional price risk. For example, a retailer with customer load in SA may hedge their risk by buying VIC-SA SRD units along with Victorian swaps (or along with owning generation in Victoria). Because they expect that netted SRD units will be less effective for inter-regional hedging, market participants may seek alternatives to hedge their exposure.[51] Some stakeholders raised concerns about their ability to use netted SRD units to meet the Retailer Reliability Obligation (RRO) and potential obligations under South Australia's proposed Firm Energy Reliability Mechanism (FERM), adding to the need for alternative hedging strategies.[52]

Stakeholders considered that the main alternative for retailers would be to buy standard swap and cap contracts in the region where they are serving load. This may increase demand for standard contracts and lead to higher contract prices which could translate to higher costs for retail customers.[53]

Stakeholders consider that netting would adversely affect retail competition, especially in SA

Several submissions to the directions paper raised concerns that netting would adversely impact retail competition. Stakeholders noted that retailers often rely on SRD units to serve load in a region where they do not own generation assets or hold contracts.[54] If netting was to make SRD units less effective for inter-regional hedging, retailers may face challenges serving load in other regions. As noted above, another alternative for retailers is to hold contracts in-region, but market participants expect that contract prices may also rise. Similarly, stakeholders were concerned that netting may impact contract market liquidity by limiting generators' ability to offer competitive contracts outside their own regions. These effects on inter-regional hedging and liquidity could reduce retail competition and lead to higher retail prices and less choice for consumers in all looped regions.[55]

Stakeholders noted the effects of netting may be compounded in SA because of the pre-existing low liquidity in the SA contract market.[56] Liquidity is low in SA because it is a smaller region with few remaining thermal generators - the traditional suppliers of standard swap and cap contracts. That is, contracts at the SA RRP are not readily available.[57] Stakeholders were of the view that netting may reduce liquidity further and/or prevent retailers from hedging load using generation in

48 Submissions to the directions paper: Alinta Energy, pp.4-5; Shell Energy, p.2; Origin, p.5, Snowy Hydro, p.1; AEC, p.2; AGL, p.1.

49 Origin, for example, elaborated on the risks with netting in its submission to the directions paper. It identified specifically that netting would reduce the ability of market participants to manage risks, reduce the efficiency of inter-regional trade (and willingness of participants to trade inter-regionally) and therefore reduce overall market efficiency. Refer to pp.1, 3, 8 of Origin's submission.

50 Submissions to the directions paper: Origin, pp.5, 7; AFMA, p.1.

51 Submissions to the directions paper: Origin, p.3; ENGIE, p.2; AEC, p.3; Stanwell, pp.2, 4.

52 Submissions to the directions paper: Origin, pp.2, 6; Shell Energy, p.2.

53 Submissions to the directions paper: Origin, p.8; Stanwell, p.3; AFMA, p.3; Alinta Energy, p.5; ENGIE, p.2; AEC, p.3; Stanwell, pp.2, 4.

54 Submissions to the directions paper: Origin, p.3; Delta, p.1; Snowy Hydro, p.2; AFMA, p.3; AGL, p.2; Alinta Energy, pp. 3-6; Stanwell, p.2; Alinta Energy letter - received 9 September 2025, pp.3-4.

55 Submissions to the directions paper: Alinta Energy, p.5; Alinta Energy letter - received 9 September 2025, pp.3-4.

56 Submissions to the directions paper: Origin, p.1; Delta, p.1; AGL, p.2; EnergyAustralia, p.3; Alinta Energy, p.3; AGL, p.2.

57 Alinta Energy, submission to the directions paper, p.3.
Alinta Energy noted that "ASX Open Interests in all exchange traded products across the terms with 2026 (as of 7 July 2025 Close) show SA contracts providing only ~1% of all Open Interests across ASX NEM markets."

a different region, potentially reducing their “willingness to serve load in certain regions.”[58] Again, some noted that meeting RRO or FERM obligations may compound these challenges.[59] Alinta Energy considered that retailers may choose to exit SA as a result of these issues and that netting would “further entrench the market power of large vertically integrated participants in South Australia”.[60]

Several market participants also raised concerns that netting may contradict the aims of the NEM Expert Panel Review to improve liquidity in risk management markets.[61]

Finally, some stakeholders considered that netting may encourage vertical integration within the same region, as an alternate approach to contracting in-region, if netted SRD units are less effective for inter-regional hedging. In the longer term, this could disrupt efficient investment signals by favouring physical hedging over inter-regional trade. That is, locational investment decisions could be overly influenced by the ability to hedge in a region, which may not provide the lowest-cost energy to consumers.[62] If, as market participants expect, netting favours vertical integration, this could also disproportionately impact smaller retailers that do not own generation assets.[63]

Stakeholders consider netting would reduce the SRA proceeds flowing to consumers

Market participants noted that the perceived reduced hedging value of SRD units could cause auction clearing prices to fall.[64] This would mean lower SRA proceeds flowing to CNSPs and hence to consumers. Origin provided analysis indicating that SRA proceeds per dollar of positive residues had historically been lower when a form of netting was applied in the NEM, compared to the current arrangements.[65]

Some stakeholders also reiterated concerns that market participants may not purchase netted SRD units at all.[66] If so, the unsold IRSR would be allocated to CNSPs as a variable positive cash flow, reducing the benefits of the SRA in providing predictable cash flow to CNSPs and consumers.

AEMO was neutral towards the directions paper proposal

AEMO did not strongly support nor strongly oppose the directions paper netting proposal. It noted that our netting proposal was similar to an approach it had considered, but decided against, in its previous consultation. Similar to market participants, AEMO considered that “deducting negative IRSR from positive IRSR will have a material impact on the performance of SRA units as a tool to manage interregional basis risk” and that this impact “may be understated in the AEMC’s assessment”. AEMO acknowledged, however, that there was a trade-off between these impacts on inter-regional hedging and the impacts on consumers if netting was not implemented.[67] AEMO confirmed it would be feasible to implement netting before PEC becomes operational and emphasised the importance of timely implementation:[68]

58 Submissions to the directions paper: Quote - Origin, p.2; see also Snowy Hydro, p.3.

59 Submissions to the directions paper, Origin, p.2; Shell Energy, p.2.

60 Submission to the directions paper, Alinta Energy, pp.3-4.

61 Submissions to the directions paper: AGL, p. 2; Snowy Hydro, p. 3; ENGIE, p. 2; Origin, p.2.

62 Submissions to the directions paper: Origin, p.8; AFMA, p.5, Snowy Hydro, pp.2-3; AGL, pp.1,2.

63 Submissions to the directions paper: Snowy Hydro, pp.2-3; Alinta Energy, p.5; AGL, p.2.

64 Submissions to the directions paper: AFMA, p.3; Shell Energy, p.2; Origin, pp.8-9; Alinta Energy, p.5; ENGIE, p.2; AEC, p.2.

65 Origin, submission to the directions paper, pp.8-9.
See also appendix D of the consultation paper, pp.41-45, which sets out how IRSR arrangements have evolved throughout the NEM’s history.

66 Submissions to the directions paper: Alinta Energy, p.4; ENGIE, p.2; AEC, p.2.

67 AEMO, submission to the directions paper, p.3.

68 AEMO, submission to the directions paper, p.2.

> While there are both benefits and drawbacks to the different funding arrangements [netting or recovering negative IRSR from CNSPs], AEMO's ultimate priority at this stage of the process is to obtain clarity with a final rule as soon as possible to facilitate implementation in time for the anticipated commissioning of PEC-2. AEMO therefore confirms it can implement the updated approach in the directions paper if carried through to the final rule.

The Commission's response to stakeholder feedback

Negative IRSR, as well as positive IRSR, is an unavoidable outcome of the transmission loop. The Commission acknowledges that these IRSR amounts and the costs of managing them will inevitably flow through to consumers. In this rule change we are looking for the most efficient way to manage IRSR in the transmission loop on behalf of consumers.

We acknowledge market participants' concerns that netting off may overall increase, not reduce, costs to consumers, as outlined above. Indeed, the impacts of netting off will flow through to consumers in multiple ways and some of those mechanisms act to increase consumers' bills, while others act to decrease them. However, we have weighed these impacts against the costs of managing negative IRSR risk through CNSPs, AEMO, or market customers, and we consider that market participants will be able to manage the risk at a lower overall cost to consumers for the reasons outlined in section 2.4.3. The Commission considers that netting off is therefore likely to better contribute to the achievement of the NEO compared to the rule change proposal. We are also not satisfied that the other options that did not involve netting adequately manage risks and costs for consumers.

Many of the concerns market participants have raised about the reduced effectiveness of SRD units for hedging appear to stem from the behaviour of the transmission loop, and not only from netting. As discussed in section 2.4.3, the introduction of a transmission loop will change the relationship between flows and prices in all the looped regions. This will change how SRD units behave and how participants hedge inter-regional price risk - regardless of the Commission's decision in this rule change. Inter-regional hedging as it is now is not the right counterfactual to assess the costs of alternative approaches to inter-regional hedging in the loop.

Based on our analysis of how the transmission loop impacts IRSR, we have also changed the netting approach to one based on net trade, instead of the approach set out in the directions paper. We now consider the net trade approach better meets our assessment criteria and is therefore an improvement on the directions paper approach for the reasons set out in section 2.4.3 and section 3.1.2. That is, we have designed the net trade approach to provide the most useful hedging instruments in the context of the loop. As the market adjusts to the new approach over time, this may mitigate some of the concerns raised about higher hedging costs, challenges in hedging load across regions, retail competition, liquidity impacts (including in SA), and the potential impacts on consumers.

Without operational experience of the transmission loop, we cannot know for certain how the loop and this rule change may impact retail competition and liquidity. The Commission has made a final determination based on the information available to us. We acknowledge that retail competition and contract market liquidity are important to good consumer outcomes. Although well-designed SRD units are one important component, competition and liquidity are influenced by many factors and market processes, including in SA. The Commission also notes that liquidity in NEM contract markets is a broader issue which is being considered in the NEM Expert Panel Review. In this context, and accounting for the effect of the loop itself on inter-regional hedging, we consider that the impact of netting on contract market liquidity and retail competition is likely to be less significant than some of the potential outcomes referred to in submissions.

The Commission expects that the market will take some time to adjust to the operation of a transmission loop, regardless of whether and how IRSR is netted. We acknowledge that the netting arrangements in the final rule are more complex than the existing arrangements, the rule change proposal or the directions paper proposal and will require a learning period. The impacts raised by market participants, including the potential for lower SRD unit prices or non-sale of SRD units, are likely to be most significant in the short-term and then decrease as participants adjust their bidding and hedging strategies to the loop. We consider that net trade is likely to provide the most efficient risk management and lowest costs in the long term, even though there is a risk of disruption in the short term which may expose market participants to risk, impact competition, and/or result in costs for consumers.

With time, additional options may emerge for market participants to manage risk, if they are needed. In the directions paper, we discussed how market participants may be able to combine netted SRD units with trading amongst themselves to hedge more efficiently. Specifically, we considered there was an opportunity to trade the market surplus that can result from price separation between certain regions (despite netting), and/or SRD unit payouts that are in excess of what the unit holder needs.[69] However, participants' feedback was that these bespoke contracts were unlikely to be feasible, at least initially, due to the potential cost and complexity of such arrangements.[70] The Commission considers that this type of additional trading could take place more easily under the net trade approach, as outlined in appendix B. We acknowledge that these trades may not emerge immediately, but we would expect market participants to explore these options over time if there is a financial incentive to do so. Perhaps more importantly, we expect that netting based on net trade may reduce the need for additional bilateral trades compared to proportional netting (or perhaps even compared to the existing arrangements), because the SRD units themselves will be better aligned to participants' exposures.

The Commission acknowledges stakeholders' concerns that netting may result in lower SRA proceeds flowing to consumers. To an extent, this reflects fair value, because netting will reduce the total pool of SRD unit payouts compared to what it would be if the current arrangements were applied to the loop. Therefore, it may be an appropriate trade-off for removing consumers' direct (via CNSPs) exposure to negative IRSR. However, if there is an outsized impact on auction prices, this may also mean the SRA framework is not providing overall value to consumers (see chapter 5). We also maintain our view put forward in the directions paper that it is unlikely that SRD units would go unsold. Netted SRD units are guaranteed to pay out a positive amount, or at worst zero. As there is no reserve price, it would be rational for eligible auction participants to place bids of at least $0, so we expect that the SRD units would be sold even if payouts are uncertain or expected to be low.[71]

In making this final determination, the Commission acknowledges there is significant uncertainty around the actual operational outcomes of the transmission loop. Although there has been some market modelling, for example as part of AEMO's PEC Market Integration process, it is difficult to predict with certainty how PEC will influence market outcomes, especially considering how participants' future operational decisions will interact with the loop. This is one of our reasons for

69 Refer to appendix A of the directions paper, pp.56-57.

70 Submissions to the directions paper: AEC, p.2; AFMA, p.4; EnergyAustralia, p.3.

71 The auction rules specify the requirements for bids and do not currently include a reserve price. Section 9.2 requires bids to be an amount not less than zero.

recommending a review of IRSR arrangements, including for transmission loops, in the future (see chapter 5).

2.4.6 Other options we considered would not adequately manage risks and costs for consumers

Throughout this rule change we have considered other options apart from netting or the draft rule approach, including the solution proposed in the rule change request. This section sets out our analysis of these other options and the Commission's response to stakeholder feedback. We also discussed these options in the directions paper and some of the options in the draft determination.[72] We consider that none of these options would adequately manage risks and costs for consumers.

The rule change proposal would place costs and risks on consumers

We consider that the final rule is likely to better contribute to the achievement of the NEO than the solution proposed by AEMO in its rule change request. AEMO proposed to maintain the separation of positive and negative IRSR in the loop, with negative IRSR flowing to CNSPs and positive IRSR being sold through the SRA. To manage the potential for large negative IRSR, AEMO proposed to reallocate negative IRSR amongst the interconnectors in the loop when the net residue for the loop is positive.

Under AEMO's proposed rule:

- Negative IRSR arising on any arm of the loop would be reallocated to arms with positive IRSR in the same trading interval, in proportion to the positive IRSR on those arms.
- Negative IRSR would then be recovered from the importing CNSP(s) for the arm(s) to which it was reallocated (and subsequently passed on to consumers).
- All positive IRSR on any arm of the loop would be distributed to relevant SRD unit holders via the SRA, with the SRA arrangements staying the same.[73]

In submissions to the directions paper, several market participants supported AEMO's original proposal, noting AEMO had developed the approach in consultation with the market.[74] AEMO considered its proposal would still have benefits, but stated that its priority was the on-time implementation of the final rule.[75] While the Commission has decided not to pursue AEMO's original proposal, we have worked closely with AEMO to enable the final rule to be implemented before PEC is operational.

The Commission's concern with AEMO's original proposal is that it would recover negative IRSR directly from CNSPs in one or two regions in each instance (which would likely not be correlated with the offsetting SRA proceeds that CNSPs receive). It is possible that a large or extreme amount of negative IRSR could be allocated mostly or entirely to a single region, which would place material costs and risks on consumers and CNSPs, as outlined below. These costs and risks would arise if the existing arrangements were applied to transmission loops, and we consider AEMO's rule change proposal does not adequately address them.[76]

72 Refer to directions paper, section 2.5, p.20. Refer to draft determination, sections 3.2.3 to 3.2.5, pp.24-28.

73 Any unsold IRSR on any arm of the loop would be allocated to the CNSP for the importing region and then provided to consumers through reductions to transmission prices.

74 Submissions to the directions paper: AFMA, p.8; Delta, pp.1-2; ENGIE, p.3; Origin, pp.2, 10; Alinta Energy, pp.1, 7.

75 Submission to the directions paper, AEMO, p.2.

76 Refer to section 3.2.4 of the draft determination, pp.24-27.

Recovering all negative IRSR from CNSPs would expose CNSPs to cash flow risks

In a transmission loop, the potential for extreme negative IRSR in any one billing period exposes CNSPs to cash flow risk.[77] Although CNSPs recover the negative IRSR from customers through transmission prices, there is a timing mismatch between CNSPs' obligation to pay and their ability to recover negative IRSR from customers. CNSPs set prices based on a forecast of negative IRSR, and negative IRSR in the transmission loop is likely to be unpredictable, highly variable, and CNSPs may not be able to forecast it accurately.

- CNSPs set transmission prices in March each year at the level required to recover their allowed revenue for the upcoming financial year.
- The allowed revenue includes an estimate of negative IRSR for the upcoming year.
- This amount is recovered (along with other costs) in a smoothed fashion over the year through the amounts billed to transmission customers.
- However, CNSPs are required to pay to AEMO the actual amounts of negative IRSR that arise in any given billing period throughout the year so that AEMO can balance settlement.[78] Currently, payment is due 14 days after the end of each billing period,[79] but this is likely to be earlier after the *Shortening the settlement cycle* rule commences on 9 August 2026.[80]
- If the actual amount of negative IRSR paid by CNSPs over the year is not the same as the estimate used to set transmission prices, a 'true-up' is required in the following year. Any over- or under-recovery of negative IRSR for that year is accounted for, in present value terms, in the subsequent year's pricing, along with a new estimate of negative IRSR for the forthcoming year.[81] These true-up amounts may be large because negative IRSR is difficult to forecast.

If negative IRSR is extreme in a billing period,[82] then CNSPs need to have significant funds available at short notice. This is the case even if the CNSP has accurately forecast negative IRSR for the year, because the extreme period of negative IRSR could arise early in the year before the CNSP has recovered the full year's charges. In addition, if negative IRSR is large over multiple consecutive billing periods, the CNSP may not have sufficient funds available to manage the cumulative negative cash flow, given its revenues are set annually.

Several stakeholders acknowledged the cash flow risk to CNSPs in submissions to the directions paper.[83] However, Alinta Energy disagreed with the Commission's analysis of the relative risks and costs involved for CNSPs and market participants, considering that CNSPs are "better placed to absorb these risks as large businesses with substantial asset bases and regulated returns."[84] The Commission maintains its view stated in the directions paper that the cash flow risk associated with negative IRSR would have significant adverse impacts on CNSPs, outlined above, and in turn consumers, outlined below. We consider that market participants are best placed to manage IRSR in a net positive transmission loop for the reasons stated in section 2.4.3.

77 Specifically, there is a risk that a CNSP may not be able to meet its obligation to pay AEMO for negative IRSR for a given billing period, which is essential for AEMO to balance settlement of the market under Chapter 3 of the NER.

78 Clause 3.6.5(a)(4) NER. AEMO determines the exact date by which payments of negative IRSR are due.

79 AEMO, NEM Transmission Network Service Provider Negative Settlements Residue Procedure, version 2.0, p.9.

80 AEMO, PEC Market Integration Papers, PEC Market Integration - Directions paper, November 2023, p.11.
AEMC, Shortening the settlement cycle, final determination, December 2024, https://www.aemc.gov.au/rule-changes/shortening-settlement-cycle. See also AEMO's High level implementation assessment, AEMO | Shortening the Settlement Cycle (SSC).

81 Also, because prices are set in March for the upcoming financial year, any over or under-recovery that occurs between March and June is not trued-up until the second subsequent year.

82 Refer to Box 3 in the draft determination, p.20, which shows an example where negative IRSR reaches approximately $100 million within a billing period.

83 Submissions to the directions paper: AFMA, p.1; Origin, p.9; AEC, p.3.

84 Alinta Energy, submission to the directions paper, p.6.

Consumers would face additional costs due to CNSPs managing cash flow risk

CNSPs incur costs in managing this cash flow risk, for example, interest and fees associated with holding debt facilities with banks. These costs are ultimately met by consumers through higher transmission prices. With the introduction of a transmission loop, negative IRSR in the loop is expected to increase and there is a potential for extreme negative IRSR. With the larger magnitude and greater uncertainty of negative IRSR, it would become significantly more costly for CNSPs to manage their cash flow risk and these increased costs would also be paid by consumers. Even though CNSPs are only permitted to recover the actual amount of negative IRSR adjusted by the regulated weighted average cost of capital (WACC), the exposure to negative IRSR will ultimately mean consumers face a number of risks in the long run. This would include the increased costs of financing negative IRSR (including the costs of holding debt facilities), which could be passed through either by increases to the WACC or a working capital allowance approved by the Australian Energy Regulator (AER). Unpredictable negative IRSR cash flows and the need to maintain additional debt facilities could also adversely impact CNSPs' debt covenants and credit metrics, affecting their ability to provide services to customers.[85] Following the draft determination, CNSPs provided further information to the Commission, including modelling results, to demonstrate the potential impacts of negative IRSR cash flow risk on their businesses.

Recovering all negative IRSR in the transmission loop from CNSPs would place a risk of extreme and unexpected negative IRSR on consumers:

- directly, as consumers would ultimately pay for this IRSR through increased transmission prices. While consumers do not pay negative IRSR immediately as it arises, they do face the full cost of negative IRSR over time. CNSPs initially pay the negative IRSR and recover it through transmission prices with some delay. This delays consumers' exposure to the negative IRSR but does not remove it. CNSPs are acting as creditors, not as parties that hedge risk.[86] and
- indirectly, because the cost that CNSPs would incur in managing the possibility of extreme negative IRSR would ultimately also flow to consumers.

Retaining the existing arrangements would also place costs and risks on consumers

As part of this rule change process we considered whether the existing arrangements for managing IRSR would be appropriate for a transmission loop. We concluded that retaining the existing arrangements would not adequately manage the costs and risks to consumers.

Under the existing arrangements:

- All negative IRSR on any arm of the loop would be allocated to the CNSP for the importing region, and then recovered from consumers through increases to transmission prices.
- All positive IRSR on any arm of the loop would be distributed to relevant SRD unit holders via the SRA.[87]

We found that applying the existing arrangements to a transmission loop would place costs and risks on consumers by:

85 Submissions to the draft determination: ENA, p.2; Transgrid, p.3.

86 Most end consumers (other than large transmission-connected customers) do not directly face transmission pricing, but pay transmission prices indirectly via their retailer and Distribution Network Service Provider. However, most retailers update their prices annually, in part reflecting changes to their input costs, including distribution use of system charges, which are also updated annually reflecting transmission prices paid by Distribution Network Service Providers. As such, unexpected changes to negative IRSR do flow to end consumers, albeit with a delay.

87 Any unsold IRSR on any arm of the loop would be allocated to the CNSP for the importing region and then provided to consumers through reductions to transmission prices.

- exposing consumers to the unhedged risk of negative IRSR, which could be substantial (see section 2.4.1), and
- exposing CNSPs to cash flow risk, the costs of which would ultimately be recovered from consumers.

These are essentially the same risks as outlined above in regards to AEMO's rule change proposal.[88]

We consider it is important to make a final rule that addresses these costs and risks to consumers before the transmission loop begins operating. Therefore, we have not been able to extend this rule change further or defer CNSP cash flow concerns to a separate process, as suggested by some stakeholders.[89]

Submissions to the directions paper did not support retaining the existing arrangements as an enduring solution. The Australian Financial Markets Association (AFMA) noted that the existing arrangements appear sensible, although it preferred AEMO's rule change proposal, an AEMO holding fund, or recovery from market customers. AFMA considered that allocating negative IRSR to customers in the importing region was appropriate because "they have benefitted from lower spot market prices". It considered the netting proposal would increase costs (see section 2.4.5) in a way that would not align with the benefits of lower wholesale prices in the importing region.[90] Alinta Energy considered that existing arrangements for IRSR should be maintained until further assessment, consideration of feedback, and monitoring of IRSR and loop outcomes is conducted.[91]

The Commission notes that customers are typically hedged against variations in the wholesale price via their retailer. However, under the existing arrangements, transmission prices would expose them - unhedged - to variations in negative IRSR. In the case that there is extreme negative IRSR, there would be relatively lower wholesale prices in the importing region because market customers are paying less for energy than what generators are being paid. However, this benefit may not flow through to consumers in the importing region to offset the negative IRSR recovered from them, because consumers are not exposed directly to wholesale prices.

The draft rule would not adequately address the risks to consumers

The Commission has made a final rule that is different from the draft rule. Our view on the draft rule changed following stakeholder feedback on the draft determination and our further analysis.

In making the draft rule, the Commission was concerned with the risks that would be placed on consumers if the existing arrangements, or AEMO's proposal, were applied to the transmission loop.

We made a more preferable draft rule in order to mitigate the risk of negative IRSR by sharing it between consumers in all three looped regions, which would also reduce the cash flow risk for any individual CNSP. Under the draft rule:

- All negative IRSR arising on the arms of a transmission loop would be recovered from the looped regions' CNSPs in proportion to regional demand.
- All positive IRSR on any arm of the loop would be distributed to relevant SRD unit holders via the SRA, with the SRA arrangements staying the same.

88 Refer to section 2.5.6 of the directions paper and section 3.2.2 of the draft determination for further analysis.

89 Submissions to the directions paper: Alinta Energy, p.7; Delta, p.2; ENGIE, p.3; AFMA, p.7; Alinta Energy letter - received 9 September 2025, p.1.

90 Submission to the directions paper, AFMA, pp.2, 6, 8.

91 Submission to the directions paper, Alinta Energy, p. 7; Alinta Energy letter, received 9 September 2025, p.1.

We considered this approach would better contribute to the achievement of the NEO than AEMO's rule change proposal. The draft rule was shaped by stakeholder feedback to the consultation paper which suggested that the existing arrangements were not appropriate for transmission loops and that market participants wanted to maintain the existing SRA arrangements.[92]

We received feedback on the draft determination from CNSPs and some consumer groups that the draft rule would still result in significant risks, despite the sharing approach.[93] Market participants were generally supportive of the draft determination.[94]

Taking into account this feedback and our further analysis, we concluded that the draft rule does not sufficiently mitigate the risks associated with negative IRSR for consumers. Refer to section 2.3 of the directions paper for more information.

In response to the directions paper, many stakeholders acknowledged these significant risks and costs arising for consumers under options that allocate all negative IRSR around the loop to CNSPs. However, several market participants still favoured the draft rule in submissions to the directions paper.[95]

We considered an AEMO holding fund approach

We carefully considered an AEMO holding fund as a potential approach to manage the risks associated with negative IRSR. This could address the cash flow risks to CNSPs because negative IRSR would initially be drawn from a fund managed by AEMO, before being recovered from CNSPs at a later date. AEMO would also delay payment of SRA proceeds (and where applicable, unsold IRSR) to CNSPs, which would help to fill the fund. Apart from these general principles, there are several different ways that such a fund could be set up and managed.

Several stakeholders supported an AEMO holding fund

Submissions to the directions paper indicated that several market participants considered the AEMO holding fund option had merit.[96] They considered this would be a more targeted way to address the CNSP cash flow issue while avoiding impacts to the SRA framework.[97] ENA, although it supported the netting off proposal, also suggested returning to the AEMO holding fund concept in a future review.[98] Transgrid suggested a temporary AEMO facility could be used to manage transitional cash flow risks.[99]

Stakeholders provided a range of suggestions for how the AEMO holding fund could work. AFMA suggested that the holding fund could "delay the recovery of negative residues from TNSPs to allow the AER to make their recovery retrospective", with AEMO managing cash flow risk instead. AFMA considered that AEMO may be better placed to manage cash flow risk than CNSPs because it "does not face the same regulatory challenges that TNSPs [face] regarding allowances for financing costs", and could potentially finance negative IRSR at a lower cost to consumers because "unlike a TNSP, they [AEMO] would not expect to earn a profit from delivering this

92 Refer to section 2.2 (pp.2-4) and section 3.3 (pp.28-31) of the draft determination.

93 Submissions to the draft determination: EUAA, p.1; ENA, p.2; Transgrid, pp.1-2.

94 Submissions to the draft determination: Snowy Hydro, p.1; Stanwell, p.2; EnergyAustralia, p.1; AFMA, p.1; Origin, p.1; ENGIE, p.1.. Submissions to the directions paper: ENGIE, p.3; AEC, p.1; Origin, pp.2, 10; AGL, p.2, Alinta Energy, pp.6-7; Stanwell, p.2; Shell Energy, p.2.

95 Submissions to the directions paper: ENGIE, p.3; AEC, p.1; Origin, pp.2, 10; AGL, p.2; Alinta Energy, pp.6-7; Stanwell, p.2; Shell Energy, p.2.

96 Submissions to the directions paper: Delta, p.2; Shell Energy, p.2; AFMA, p.6; Origin, p.9; Alinta Energy, p.7; Snowy Hydro, p.2; AEC, p.4; AGL, p.3. Shell Energy, submission to the consultation paper, p.4.

97 Submissions to the directions paper: AFMA, p.6; Alinta Energy, p.7; Snowy Hydro, pp.2-3; Shell Energy, p.2; Origin, p.9.

98 ENA, submission to the directions paper, p.2.

99 Transgrid, submission to the directions paper, p.6.

service".[100] Similarly, ENA noted "[t]he cost of debt for a pooled fund may be more cost effective than an expandable short notice debt facility with each CNSP."[101]

Shell Energy also outlined a possible approach in its submission to the consultation paper that it considered would allow CNSPs to recover negative IRSR on an ex post basis, instead of relying on forecasts. Under Shell Energy's preferred approach, AEMO would hold SRA proceeds in trust until the end of the quarter to fund negative IRSR, but would still recover negative IRSR from CNSPs on a weekly basis if it exceeded the available SRA proceeds.[102]

Alternatively, AGL suggested delaying payments to SRD unit holders "once a certain threshold of negative residues has been reached (on the understanding that very high positive cashflows have accumulated in these circumstances)."[103] This could potentially avoid placing cash flow risk on either AEMO or CNSPs by transferring some risk to SRD unit holders.

Transgrid's suggested temporary AEMO facility would only be intended to help manage cash flow risks in the early years of PEC operation.[104] It suggested that AEMO could hold back unsold IRSR associated with terminated or unsold units (including any units that are not auctioned at all). AEMO would then allocate fixed payments to CNSPs equal to their forecast SRA proceeds revenue, with any excess unsold IRSR returned to CNSPs in the following year.[105]

We consider an AEMO holding fund has drawbacks and is not in consumers' interest

The Commission's view is that an AEMO holding fund would not adequately manage the costs and risks to consumers.

In order to fully address the cash flow risks for CNSPs, we would need to ensure that the holding fund always has sufficient funds available to fund negative IRSR in weekly settlements. Holding back SRA proceeds (the amount paid by SRD unit holders to purchase units) would not be sufficient by itself because there is no guarantee that SRA proceeds will exceed negative IRSR. Therefore, AEMO would need to either hold back SRD unit payouts (the IRSR distributed by AEMO to SRD unit holders), or potentially take on debt.

Requiring AEMO to take on negative cash flow risk to fund negative IRSR could place settlement at risk, which would have flow-on impacts for all market participants. This risk is material because of the potential for extreme negative IRSR to occur. The risk to settlement could be avoided by AEMO taking on debt, but we consider that AEMO would not necessarily be able to obtain lower financing costs than CNSPs, as some stakeholders suggested.

Therefore, AEMO would need to delay the payment of SRD unit payouts in order for an AEMO holding fund to effectively address the CNSP cash flow risks. We consider this is undesirable. Stakeholders have suggested that an AEMO holding fund could allow CNSPs to recover negative IRSR retrospectively, instead of recovering based on advance forecasts.[106] However, since CNSPs set transmission prices annually, SRD unit payouts would need to be held back for at least a year to enable this, if not longer. This would create a significant cash flow risk for SRD unit holders. On average, positive IRSR is expected to be much larger than negative IRSR, so (consistent with AGL's suggestion) AEMO may not need to hold back all SRD unit payouts.[107] However, due to the

100 AFMA, submission to the directions paper, pp.6-7.

101 ENA, submission to the directions paper, p.2.

102 Shell Energy, submission to the consultation paper, p.4.

103 AGL, submission to the directions paper, p.3.

104 See section 4.3.3 for more detail on CNSPs' feedback about transitional cash flow risks.

105 Transgrid, submission to the directions paper, p.6.

106 AFMA, submission to the directions paper, p.6
Shell Energy, submission to the consultation paper, p.4

volatility of both positive and negative IRSR, these measures would be unlikely to work unless AEMO or CNSPs also took on some cash flow risk, which is undesirable.

Finally, even if an AEMO holding fund could be set up successfully to resolve CNSP cash flow risk, consumers would still be exposed to the full cost and risk of negative IRSR. While negative IRSR costs would be smoothed over the year from customers' perspective, negative IRSR would still be volatile on a year-to-year basis and this would be reflected in customers' bills. It remains our view that market participants can manage negative IRSR at a lower cost to consumers than either CNSPs or AEMO.

We considered recovering negative IRSR from market customers

In this option, all negative IRSR arising in the transmission loop would be allocated to market customers, for example, as a new type of non-energy cost, determined in proportion to their load. Market customers are market participants that purchase electricity from the spot market, including retailers and some large loads.

This approach would remove the cost and risk of managing negative IRSR from CNSPs, and instead allocate it to market customers. As market participants, market customers may be relatively well-placed to manage the negative IRSR and associated cash flow risks.

AFMA and Delta considered that this option may have advantages because it would allow retailers to recover negative IRSR from customers in a smoothed fashion without changing the existing SRA arrangements.[108] Transgrid did not support this option because of the potential risk placed on market customers "with no interest in inter-regional trade."[109] ENA, although it supported the netting off proposal, considered it would be worthwhile to test the benefits and risks of recovering negative IRSR from market customers in a future review.[110] AGL made a similar suggestion that negative IRSR could be recovered "through normal AEMO market recovery processes, e.g. directions".[111]

The Commission's view remains that allocating negative IRSR to market customers would not adequately manage the costs and risks to consumers, for two key reasons. First, allocation to all market customers would also expose any market customers that do not trade inter-regionally to negative IRSR. We expect that this could disproportionately impact smaller retailers that may operate in only one region, hindering retail competition. Secondly, this approach would likely result in unhedged negative IRSR being passed through to end users (even if they are not market customers in their own right). In particular, large commercial and industrial customers may face large, unexpected charges on a direct pass-through basis. Refer to section 2.5.2 of the directions paper for more detail.

We considered an SRA scaling approach

In developing the directions paper, we considered an alternative approach where the quantity of positive IRSR that is distributed through the SRA would be reduced or 'scaled down'. This could be implemented by reducing the number of SRD units sold, or by selling the same number of SRD units but assigning a smaller proportion of total positive IRSR to each unit. Under this approach:

107 AGL, submission to the directions paper, p.3.

108 Submissions to the directions paper: AFMA, p.7; Delta, p.2.

109 Transgrid, submission to the directions paper, p.4.

110 ENA, submission to the directions paper, p.2.

111 AGL, submission to the directions paper, p.3.
While the cost of directions is recovered from a broader group of market participants (i.e. cost recovery market participants), we expect that recovering negative IRSR in this way would have similar drawbacks to recovering it from market customers only.

- All negative IRSR on any arm of the loop would be allocated to CNSPs, and then recovered from consumers.
- Some percentage of the positive IRSR arising on an arm of the loop would be distributed to SRD unit holders, in a similar manner to the existing SRA arrangements.
- The rest of the positive IRSR would be allocated directly to CNSPs, and then returned to consumers.

The intent would be to reduce the risk faced by consumers and CNSPs relating to negative IRSR. When negative IRSR is large, and the loop is net positive, positive IRSR must also be high. This means the allocation of positive IRSR to CNSPs would be somewhat correlated with negative IRSR and would offset each other. This may make CNSPs' total cash flows less variable and easier to forecast (and more likely to be positive) and therefore reduce the cost and risk to consumers.

However, it would be complex to determine the right proportions of positive IRSR to allocate to CNSPs and SRD unit holders in order for this approach to effectively address the risks. Allocating the wrong amount would increase risks for both parties. Refer to section 2.5.3 of the directions paper for more detail.

Stakeholders did not support this option in submissions to the directions paper. ENA noted the complexity of the approach, Transgrid considered it was too risky, and Snowy Hydro was concerned about the impact on SRD units.[112] We also consider the scaling approach would not adequately manage the costs and risks to consumers.

Stakeholders raised other alternative options

A 'micro-slice' is an alternative way to represent PEC in the dispatch engine such that it runs via Victoria and does not form a loop between three regions. Shell Energy has argued that implementing PEC as part of a loop in dispatch, instead of as a micro-slice, is a key reason why consumers may be exposed to unhedged negative IRSR.[113] Consistent with AEMO's previous analysis and consultation, we consider that implementing PEC as a micro-slice would not promote the NEO because:[114]

- Although it may reduce negative IRSR, it would not remove the risk of large negative IRSR arising.
- It could result in lower dispatch efficiency because it would be a more approximate representation of the physical network.

We have previously considered whether negative IRSR in the loop could be better managed by clamping in net positive cases, as well as net negative cases. Following the directions paper, EnergyAustralia suggested "a plausible solution... would be to impose a secondary clamping threshold in light of excessive monthly or annual negative residues."[115] It remains the Commission's view that clamping in net positive cases would interfere with efficient dispatch, and would be complex and not necessarily effective.[116]

112 Submissions to the directions paper: ENA, p.2; Transgrid, p.4; Snowy Hydro, p.2.

113 Shell Energy, submission to the consultation paper, p.3.
Shell Energy, submission to the directions paper, p.1.

114 A more detailed discussion of the micro-slice approach is found in: AEMO, PEC Market Integration papers, Final report, February 2024, p.22.

115 EnergyAustralia, submission to the directions paper, p.4.

116 Refer to section 2.3.3 of the draft determination, p.9, and section 2.5.4 of the directions paper, p.22.

AGL suggested making changes to “allow [CNSPs] to manage this more effectively by giving more flexibility in their recovery from customers.”[117] Similarly, Origin, suggested “changes to TNSP cost recovery timing”.[118] The Commission notes that transmission prices are set annually as part of the economic regulation framework under chapter 6A of the NER. Transmission prices are then used subsequently to set distribution prices and retail prices. It is not clear that the recovery of negative IRSR from consumers could be accelerated sufficiently to address the risk of CNSPs being liable for extreme negative IRSR in a single billing period. Further, making any changes to the transmission pricing framework would be complex and have many flow on consequences since the revenue requirements for TNSPs are considered holistically. We consider it would not be appropriate to make changes for how negative IRSR is recovered in isolation as part of this rule change.

The Australian Energy Council (AEC) and Origin also raised the possibility of allocating negative IRSR via negative hedging instruments - that is, allowing auction participants to agree to pay negative IRSR in exchange for receiving a fixed revenue stream.[119] While this approach is not feasible in the current rule change because of the complexity of designing an auction for such instruments, and prudential implications, we consider it may be appropriate to explore in a future review (see chapter 5).

117 AGL, submission to the directions paper, p.3.

118 Origin, submission to the directions paper, p.9.

119 Submissions to the directions paper: AEC, p.4; Origin, p.9.

3 How our rule will operate

In this chapter:

- Section 3.1 outlines the netting approach in the final rule and our rationale.
  - Section 3.1.1 explains why we consider netting off IRSR in a transmission loop is likely to better contribute to the NEO than the rule change proposal.
  - Section 3.1.2 explains how netting based on net trade improves on the directions paper approach.
- Section 3.2 describes how netting based on net trade works in detail.
- Section 3.3 explains how cash flows including net negative IRSR, SRA proceeds, and unsold IRSR will be allocated to CNSPs.
- Section 3.4 describes the reporting arrangements in the final rule.

3.1 The final rule implements a netting approach for IRSR in a transmission loop

Box 2: Key points

- The Commission has made a more preferable final rule to net off IRSR in transmission loops using a net trade approach.
- Under the final rule:
  - In net positive cases, net positive IRSR is distributed to SRD unit holders based on net trade.
  - In net negative cases, net negative IRSR is recovered from CNSPs in the looped regions according to regional demand.
- We consider that the netting approach in the final rule should support efficient risk management in the loop, thus keeping costs as low as possible for consumers.
- We previously proposed netting off IRSR in transmission loops in the directions paper. This was a change from the draft rule and different to the rule change proposal.
- The net trade approach in the final rule also differs from the netting approach that we proposed in the directions paper.
- Following stakeholder feedback and further analysis, we consider that net trade improves on the directions paper approach because it is likely to have more benefits for inter-regional hedging.

The final rule will net off IRSR in transmission loops. Generally speaking, under a netting off approach, positive and negative IRSR on individual arms of the loop is pooled together. The remaining net loop IRSR, if it is positive, is distributed to SRD unit holders. When the net loop IRSR is negative, the net negative IRSR is recovered from the CNSPs in the looped regions according to regional demand.

The Commission considers that netting off IRSR in transmission loops promotes the NEO because it manages costs and risks for consumers while supporting efficient inter-regional hedging (section 3.1.1). The final rule is a more preferable rule which we consider is likely to better contribute to the achievement of the NEO than the rule change proposal because it will manage the cost and risks for consumers more effectively.

3.1.1 Why we are netting off for the final rule

The final rule will net off IRSR in transmission loops based on net trade, which we consider will support efficient risk management in the loop, thus keeping costs as low as possible for consumers. Netting off allows both positive and negative IRSR, in net positive cases, to be managed by market participants. We consider that market participants should be able to manage IRSR more efficiently, and thus at a lower cost to consumers, than other parties. Furthermore, we have designed the net trade approach in the final rule to support inter-regional hedging more effectively than the directions paper proposal, as set out in section 3.1.2.

The final rule will also net off IRSR when the loop is net negative, which further contributes to managing the risks for CNSPs and consumers (see section 3.2.2).

Our detailed rationale for netting IRSR in transmission loops is set out in section 2.4.

3.1.2 Netting based on net trade improves on the directions paper approach

Under the final rule, IRSR in a transmission loop will be netted off based on the concept of 'net trade'. This differs from the netting design we proposed in the directions paper.

The directions paper set out four design options for netting off in transmission loops:

- proportional netting, the approach recommended in the directions paper
- net trade, referred to as 'alternative option 1' in the directions paper
- netting off by directional interconnector on a quarterly basis ('alternative option 2')
- creating a new whole-of-loop SRD unit category ('alternative option 3').

The net trade approach reassigns power flows and IRSR between the arms of the transmission loop to reflect the overall transfer of energy between the loop regions. The net trade method is outlined at a high level below, and section 3.2 provides more information.

- In cases where the net loop IRSR is positive ('net positive'), the 'net trade' is calculated for each relevant directional interconnector in each trading interval. This applies in all net positive cases, including where there is positive IRSR on all three arms of the loop.
- Net trades represent the net export from, or net import to, a region. For example, if 100 megawatts (MW) flows from Victoria to SA and 120MW flows from NSW to Victoria, then Victoria is net importing 20MW.
- Net trade flows from net exporting regions to net importing regions in the loop. Usually, there will be a net trade on two arms of the loop while the remaining arm will have no net trade.
- IRSR is assigned to each arm of the loop by multiplying the net trade by the price difference between regions. This amount is distributed to SRD unit holders for each relevant SRD unit category, after adjusting for transmission losses.[120]
- Distributing IRSR in this way when the net loop IRSR is positive usually removes negative IRSR on individual arms of the loop. When negative IRSR on any arm remains, this will be deducted from the SRD unit payout on the remaining arm, which we refer to as 'secondary netting'.
- As a result, all net positive IRSR will be distributed to SRD unit holders and nothing will be recovered from CNSPs in these cases.

120 SRD unit categories correspond to directional interconnectors, such as NSW-VIC for flows from NSW to Victoria and VIC-NSW for flows from Victoria to NSW.

- In cases where the net loop IRSR is negative ('net negative'), this net negative amount will be recovered from CNSPs and all SRD unit payouts will be zero for that trading interval (see section 3.2.2). The net negative IRSR will be recovered from the CNSPs in proportion to regional demand (see section 3.3.2).

The Commission has decided to implement the net trade approach for the final rule because we consider it is likely to have more benefits for inter-regional hedging than proportional netting, while still addressing the risks of IRSR in a transmission loop for CNSPs and consumers. The design of the net trade approach is the same as 'alternative option 1' set out in the directions paper. The benefits of the net trade approach compared with proportional netting are as follows.

Allocating net positive IRSR based on net trade is more consistent with the market's underlying price exposures

The net trade approach is designed to maintain the effectiveness of an SRD unit as a hedge between two regions by reflecting the market's underlying inter-regional price exposures. In a loop, power flows must take all available paths from generation to load due to Kirchhoff's law. Unlike proportional netting, the net trade approach ignores the route that the electricity took from generation to load, which does not necessarily align with the inter-regional price separation risk. Instead, the approach focuses on the net quantity of generation in each region serving load in another region. We consider that distributing the total (net positive) IRSR in this way may better align with market participants' hedging requirements because SRD unit payouts will reflect the net energy transfer and price difference between two regions and better align with the price separation risk.

Under the proportional netting approach, the distribution of net positive IRSR amongst SRD unit categories would be unlikely to closely resemble market participants' underlying exposure to price separation. Market participants' exposure is not necessarily aligned with physical power flows and the IRSR assigned to each arm under the existing methodology. Market participants would have to buy a combination of SRD units on all three arms to hedge their exposure between two regions. (Some stakeholders identified in submissions to the directions paper that purchasing units on one arm only would not be sufficient to hedge their exposure.[121] However, this approach may not be reliable for a number of reasons. First, it would require determining the required quantity of units on each arm, based on forecasts, and bidding to purchase those quantities. Second, since the units are not firm (and the firmness could vary between arms), any instances of reduced flow on any arm of the loop could reduce the effectiveness of that combination of units as a hedge. We expect this issue would also occur if no netting was applied, because SRD unit payouts would be based on the path by which electricity flows, rather than which regions are actually exporting generation to other regions. That is, without net trade, participants would need to over-hedge to keep their risk at the same level as could be achieved with the net trade approach.

Stakeholders gave limited feedback on the detailed netting design

We considered the net trade approach again following stakeholder feedback to the directions paper. Although we received limited direct feedback on the merits of proportional netting compared to the other design options we considered, some of the broader feedback on netting raised concerns, which we consider can be mitigated by the net trade approach.

A number of stakeholders supported the proportional netting approach, or preferred it to some of the other design options presented in the directions paper.[122] Origin, which opposed netting

121 Submissions to the directions paper: Origin, pp.4-5; AFMA, pp.3-5; EnergyAustralia, p.3.

122 Submissions to the directions paper: Origin, p.10; ENA, p.3; EUAA, p.1; Transgrid, p.3.

overall, stated that alternative design options such as net trade, "would introduce greater uncertainty and further weaken the value of SRD units."[123] AEMO was comfortable with proportional netting, noting the similarity to an approach it considered in its earlier consultation process.[124] Transgrid said that it would support either the proportional netting or net trade options if they maximised the value of the SRA to consumers.[125]

Several market participants raised concerns that netting, as proposed in the directions paper, would result in insufficient IRSR being available for inter-regional hedging on a given arm of the loop.[126] The Commission had identified this issue in the directions paper and provided a worked example showing how participants may be able to manage risk more effectively by trading IRSR amongst themselves.[127] However, some stakeholders considered it was unlikely that such additional trading could overcome the perceived shortcomings of the proposed netting approach, outside of a simplified example.[128] This feedback was given regarding netting in general, although the Commission's example and stakeholders' subsequent analysis used proportional netting to illustrate their views. However, the concerns raised about the netting proposal caused us to think further about how the detailed netting design impacts market participants' hedging strategies, as discussed above. We consider that net trade will package IRSR into SRD units that are more likely to meet market participants' hedging needs compared to proportional netting. Refer to section 2.4.5 and appendix B for more information.

On netting design generally, although it opposed netting overall, Shell Energy expressed support for SRD units being designed to pay out positive amounts but not negative amounts.[129] Shell Energy also supported the approach to netting in each trading interval separately "so that there will be no netting of positive and negative residues between trading intervals.[130] The Commission notes that the net trade approach in the final rule does not net between trading intervals. In the directions paper we considered an approach that would net off positive and negative IRSR across trading intervals ('alternative option 2'), but decided against it because it was unlikely to support effective inter-regional hedging, and may still place significant costs and risks on consumers (as well as cash flow risk on CNSPs).[131]

3.2 How netting will work under the final rule

Box 3: Key points

- The final rule applies netting based on net trade whenever the net loop IRSR is positive ('net positive cases'). This includes cases where positive IRSR arises on all three arms of the loop.
- Under the net trade approach:

123 Submission to the directions paper, Origin, p.10.

124 AEMO, submission to the directions paper, p.2.

125 Transgrid, submission to the directions paper, p.3.

126 Submissions to the directions paper: Origin, pp.3-6; AFMA, pp.1-2, p.5; EnergyAustralia, p.3. Origin and AFMA provided detailed worked examples showing how participants could be 'under-hedged' using netted SRD units and, in their view, would need to purchase more expensive swap cover instead.

127 Refer to appendix A of the directions paper, pp.56-57.

128 Submissions to the directions paper: AFMA, pp.3-5; AEC, pp.1-2; EnergyAustralia, p.3.

129 Shell Energy, submission to the directions paper, p.3.

130 Ibid.

131 Refer to section 3.2.3 of the directions paper, pp.31-32, for further information.

- A net trade quantity is determined for the relevant directional interconnectors (typically two arms of the loop), representing the net energy transfer between regions. The net trade quantity is defined as the net export from, or net import to, a relevant region.
  - The SRD unit payouts for each directional interconnector are then calculated by multiplying the net trade quantity by the difference in price between the regions.
  - If this results in a negative amount for any arm of the loop, this amount is netted off from the positive arm ('secondary netting').
  - All net positive IRSR arising on the loop is distributed to SRD unit holders.
- The final rule nets off IRSR in net negative cases, with net negative IRSR to be recovered from CNSPs. We decided to maintain this approach to managing net negative IRSR from the directions paper after considering stakeholder feedback.
- Netting off (in both net positive and net negative cases) only applies to the interconnectors that form part of a transmission loop.
- We have accounted for transmission losses and special case loop outcomes in the final rule.
- Appendix E summarises the final rule by reference to each clause.

3.2.1 Net trade will apply in all net positive cases

The final rule will net off IRSR in transmission loops based on net trade whenever the net IRSR for the loop is positive (including cases where all arms are positive). This approach redistributes IRSR between the arms of the loop in such a way as to reflect the overall transfer of energy between regions, by using the concept of 'net trade'.

Netting based on net trade will only apply to regulated interconnectors that form part of a transmission loop (i.e. those between NSW, SA and Victoria). For interconnectors that are not part of a loop,[132] the existing arrangements will continue to apply.[133]

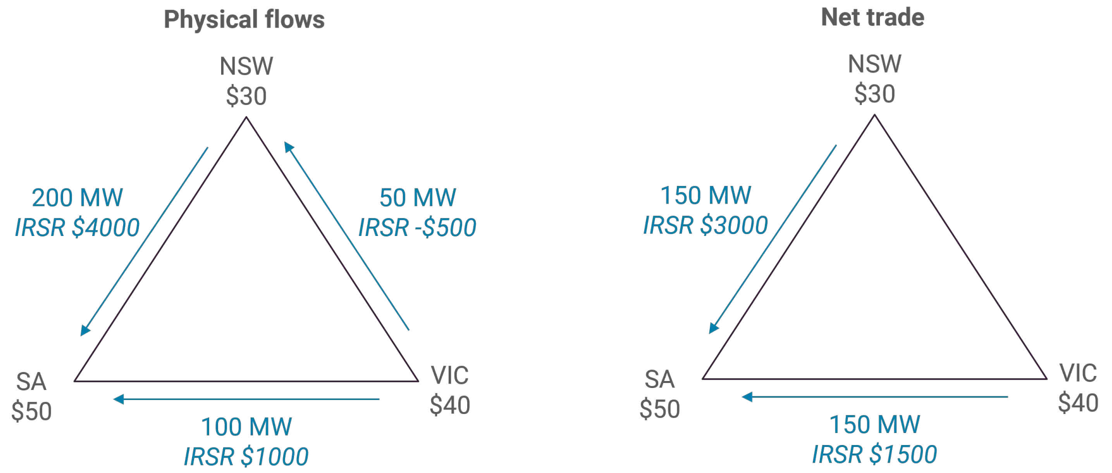
The method for netting off based on net trade works as follows, with reference to the worked example in Figure 3.1.[134] This is a conceptual description of the net trade approach. We have also included a detailed clause-by-clause explanation in appendix E to assist stakeholders in understanding the final rule.

132 Regulated interconnectors that are not part of a loop will include the interconnectors between NSW and Queensland, Basslink between Victoria and Tasmania if and when it becomes a regulated interconnector, and Marinus Link between Victoria and Tasmania if and when it is completed.

133 Clauses 3.6.6(d) and (e) of the Final Rule. Note that the SRA only applies to regulated interconnectors, which are only those interconnectors that satisfy the definition of 'regulated interconnector' in Chapter 10 of the NER.

134 Clauses 3.6.6(a) and (b) and (f)-(j) of the Final Rule.

Figure 3.1: Worked example for netting based on net trade



Note: This example uses a trading interval of one hour to simplify the calculation.

- **Determine the IRSR allocation to each directional interconnector, in the same way as the existing arrangements.**
  - This step calculates the initial amount of IRSR assigned to each directional interconnector in the transmission loop, according to AEMO's existing methodology.[135] This dollar amount is referred to as the 'allocation' in the final rule.[136]
  - AEMO's 'Methodology for the allocation and distribution of settlements residue' sets out how it calculates the IRSR allocation to each directional interconnector in the NEM.[137] This methodology is not currently referred to in the NER and so the final rule elevates this methodology to the Rules.[138] In doing so, the final rule requires AEMO to determine, for each trading interval, and set out in the methodology:[139]
    - the amount (which may be positive, negative or zero) of settlements residue assigned to each directional interconnector (the 'allocation'); and
    - the intra-regional settlements residue attributable to each region.
  - *In this example, the allocation to NSW-SA is $4000, the allocation to VIC-SA is $1000, and the allocation to VIC-NSW is -$500.*
- **Determine the net loop IRSR for the transmission loop (the 'net loop allocation' in the final rule).**
  - The net loop IRSR in a trading interval is the sum of the allocation for each arm of the loop. This amount can be positive, negative or zero.[140]

135 Under the existing arrangements, this would be the amount distributed to the relevant SRD unit holders, if it is positive. If the amount is negative, it would be recovered from the importing region's CNSP.

136 Clause 3.6.6(a), definition of 'allocation', in the Final Rule.

137 AEMO, Methodology for the allocation and distribution of settlements residue (current version: version 3, published 2 June 2024).

138 Clauses 3.6.5(a) and (b) of the Final Rule.

139 Note that AEMO already determines and sets these things out in the existing methodology and so the final rule reflects AEMO's existing methodology and practice.

140 Clause 3.6.6(a), definition of 'net loop allocation', in the Final Rule.

- If the net loop IRSR is **positive**, it is distributed to SRD unit holders based on net trade as set out in the further steps listed below.[141] The net trade approach applies in *all* net positive cases, including cases where every arm of the loop has a positive IRSR allocation (see example 2 in appendix B), and cases where one or two arms have a negative IRSR allocation (see example 3 in appendix B).
- *In this example, the net loop IRSR is +$3500/h.*
- If the net loop IRSR is **negative**, it is recovered from CNSPs as outlined in section 3.2.2.[142]
- If the net loop IRSR is **zero**, no action is required.

- **Calculate net exports or net imports (the 'net regional export quantity' in the final rule).**
  - The net export for each looped region is the sum of the flows out of the region via looped interconnectors less the sum of the flows into the region via looped interconnectors.
  - In the final rule, the net export (termed 'net regional export quantity') is calculated by summing the 'notional interconnector export flows' and subtracting the 'notional interconnector import flows' for the region. The notional interconnector export (or import) flow is the flow out of (or into) a region via a specific 'notional interconnector', as defined at the regional reference node (RRN).[143] There is a notional interconnector for each regulated interconnector and notional interconnectors are considered to connect the two relevant RRNs directly. AEMO's Methodology for the allocation and distribution of settlements residue also specifies how AEMO calculates the notional interconnector export flows and notional interconnector import flows.
  - If the net export is positive, the region is 'net exporting'. If the net export is negative, the region is 'net importing'. In the vast majority of cases there will be either two net exporting regions and one net importing region, or vice versa.[144]
  - Ignoring losses, the total net exports will be equal to the total net imports.[145]
  - *In this example, NSW is net exporting 150 MW, Victoria is net exporting 150 MW, and SA is net importing 300 MW.*
- **Determine which looped interconnectors are to be assigned a net trade.**
  - There is a net trade on any directional interconnector that links a net exporting region to a net importing region (with the direction of net trade being towards the net importing region).
  - Usually, there will be a net trade on exactly two directional interconnectors.[146]
  - *In this example, there is a net trade on NSW-SA and VIC-SA only.*
- **Determine the net trade on each of those interconnectors (the 'net trade quantity' in the final rule).**
  - The net trade quantities are determined such that the net trade quantities in and out of each region add up to its net export or net import.[147]

141 Clause 3.6.6(b)(2) of the Final Rule. However, net loop IRSR is first used to recover auction expense fees in accordance with the settlements residue auction rules, before the remainder is distributed to SRD unit holders to the extent of the unit entitlements. Also, any unsold IRSR is distributed to the CNSP for the relevant importing region, as outlined in section 3.3.4. These arrangements are consistent with the current NER.

142 Clause 3.6.6(c) of the Final Rule.

143 See the definitions of these terms in clause 3.6.6(a) of the Final Rule. The term 'notional interconnector' reflects the term used in AEMO's methodology.

144 Section 3.2.3 explains when exceptions can occur and how they will be treated.

145 Section 3.2.3 explains how losses are accounted for in the detailed implementation of the net trade approach.

146 Section 3.2.3 explains when exceptions can occur and how they will be treated.

147 Clause 3.6.6(a), definition of 'net exporting region', in the Final Rule.

- If there are two net exporting regions, the net trade quantity for the interconnector connected to each of those regions is equal to its net export.
- *In this example, the net trade on NSW-SA is 150 MW (equal to the NSW net export) and the net trade on VIC-SA is 150 MW (equal to Victoria's net export). Note that SA is importing 150 MW from each of the other regions which adds up to its net import of 300 MW.*
- If there are two net importing regions, the net trade quantity for the interconnector connected to each of those regions is equal to its net import.

- **Assign the IRSR to directional interconnectors based on net trade (the 'net trade amount' in the final rule).**
  - First, the 'provisional net trade amount' for each directional interconnector is calculated by multiplying the net trade quantity by the price difference between the regions (and adjusting for losses as described in section 3.2.3).[148]
  - The calculation of the provisional net trade amount is analogous to the calculation of IRSR under the existing arrangements (where power flow is multiplied by regional price difference), but using net trade in place of physical power flow. The provisional net trade amount may be positive (if net trade is flowing towards the higher-priced region) or negative (if net trade is flowing towards the lower-price region).
  - *In this example, the provisional net trade amount assigned to NSW-SA is 150 x (50 - 30) = $3000/h. The provisional net trade amount assigned to VIC-SA is 150 x (50 - 40) = $1500/h.*
  - The provisional net trade amounts are converted to final 'net trade amounts', which will be the SRD unit payouts for that trading interval, as follows:[149]
    - If both relevant directional interconnectors are assigned positive provisional net trade amounts, the net trade amounts are equal to the provisional net trade amounts.
    - If one directional interconnector is assigned a negative provisional net trade amount, this amount is deducted from the provisional net trade amount assigned to the positive arm. This is referred to as 'secondary netting' and is discussed in more detail below.
  - The sum of all net trade amounts, and hence the sum of all SRD unit payouts, will be equal to the net loop IRSR for that trading interval so that settlement balances.
  - *In this example, NSW-SA unit holders would receive $3000/h payout and VIC-SA unit holders would receive $1500/h payout. Other unit holders would receive no payout for this trading interval. The total payouts equal the total IRSR: $4500/h.*

The net trade method can result in different allocations to each directional interconnector (and corresponding SRD unit category) compared to either proportional netting or the existing arrangements. Indeed, it can result in higher allocations to some unit categories than would have resulted from the existing arrangements, as is the case for VIC-SA in the Figure 3.1 example. This is by design: where a certain SRD unit category is allocated a larger amount, this appropriately reflects a larger net energy transfer between the regions and thus a greater need for inter-regional hedging, as discussed in section 3.1.2.

Refer to appendix E for a more detailed explanation of how the conceptual description above relates to each clause of the final rule.

148 Clause 3.6.6(i) of the Final Rule. The method of calculation guarantees that the sum of all provisional net trade amounts will be equal to the net loop IRSR for that trading interval.

149 Clauses 3.6.6(i) and (j) of the Final Rule.

The final rule applies secondary netting when the net trade amount on one arm is negative

It is possible for the net trade calculation outlined above to result in a negative net trade amount on one arm with a positive net trade amount on another arm. In this case, the final rule will net off the negative net trade amount from the positive net trade amount that is available on another arm of the loop.[150] Usually there will only be one other arm that is allocated IRSR, and so the choice of which arm to net this amount from is clear.[151] The Commission's rationale for applying this 'secondary netting' step is as follows.

Although counter-intuitive, a negative net trade amount on one arm can occur as a normal outcome of loop dispatch, while the net loop IRSR is positive, due to the spring washer effect. It may also be more likely (or the negative net trade amount may be larger in magnitude) when dispatch is being influenced by intra-regional constraints.[152] We expect this scenario would occur in a minority of trading intervals, but would not be especially rare.

One of our key design principles for the netting off approach in this final rule is to avoid changes to the SRA that would result in prudential issues or complex auction redesign. To achieve this, we have avoided netting design features which could cause SRD units to pay out a negative amount in any trading interval. Therefore, where a negative net trade amount arises, it cannot be assigned to the SRD unit category for the directional interconnector on which it occurs. We considered whether the negative net trade amount should be recovered from CNSPs. However, the Commission's view is that recovery from CNSPs would place an additional cash flow risk on CNSPs and flow-on cost and risk to consumers, the magnitude of which is difficult to predict. For these reasons, the Commission has decided to apply secondary netting, and deduct the negative net trade amount from the positive amount allocated to the other arm with net trade. Refer to example 4 in appendix B for a worked example of secondary netting.

Secondary netting will decrease the SRD unit payout for the positive arm in trading intervals where it is applied and this may impact the effectiveness of SRD units for hedging, since the SRD unit holders will not receive the full net trade amount for that arm. There is a trade-off between this impact on SRD unit holders and the risks to CNSPs and consumers. However, all of the net positive IRSR for the loop will still be made available through the SRA, and this is sufficient for the market as a whole to hedge its risk. (In this case, the net loop IRSR for the trading interval is all allocated to one SRD unit category.) There may be an opportunity for market participants to enter into contracts for the amount netted off by secondary netting, as discussed further in appendix B.

Since netting based on net trade is only applied in net positive cases, the positive net trade amount on the second arm will be greater than the negative net trade amount that is netted off, so the relevant SRD unit will receive a positive payout. Net negative cases are treated separately, as outlined in section 3.2.2.

The discussion of the net trade approach in the directions paper included secondary netting. Stakeholders did not provide any specific feedback on secondary netting.

3.2.2 IRSR will be netted off in net negative cases

Under the final rule, all IRSR will be netted off in net negative cases, so that only net negative IRSR is recovered from CNSPs.[153] This aspect of the final rule is consistent with our proposal in the

150 Clause 3.6.6(j) of the Final Rule.

151 Section 3.2.3 explains when exceptions can occur and how they will be treated.

152 Mathematically, a negative net trade amount occurs whenever the net trade on one arm is in the counter-price direction, i.e. when there is a net export from a higher-priced region to a lower-priced one. Again, this appears counter-intuitive, and may be a result of intra-regional constraints, but can also arise from the spring washer effect because the prices in each region are influenced by the flows and constraints around the rest of the loop.

153 Clause 3.6.6(c) of the Final Rule.

directions paper, which we decided to maintain after taking feedback into account. Example 5 in appendix B provides a worked example of how netting off will operate in net negative cases. The final rule shares net negative IRSR recovered from CNSPs between the looped regions in proportion to regional demand, as discussed in section 3.3.2.

The Commission has decided to implement netting off in net negative cases for the final rule for three key reasons:

- **It contributes to managing the risk to CNSPs and consumers.** The Commission supports AEMO's intended approach to clamp net negative IRSR in the loop. However, there is still a risk that material negative IRSR could arise in net negative cases. AEMO's reporting shows that negative IRSR on non-looped interconnectors can be up to approximately $40 million quarterly, despite clamping.[154] Netting off in net negative cases would help manage this risk.
- **It promotes stability by providing continuity across net positive and net negative cases.** Failing to net off in net negative cases would lead to a discontinuity between net positive and net negative cases. That is, there would be an abrupt change in SRD unit payouts and the amount owed by CNSPs as the net loop IRSR passes through zero. This would introduce greater volatility and unpredictability in cash flows for CNSPs, which CNSPs would pass on to consumers through larger year-on-year changes to transmission prices. It would also be inconsistent in principle with secondary netting.
- **It avoids creating gaming incentives.** The discontinuity caused by not netting off could create an incentive for generators that hold SRD units to force the net loop IRSR negative in the hope of receiving un-netted SRD unit payouts. Generators may do this by adjusting their offer price or quantity when net loop IRSR is near zero – leading to inefficient dispatch outcomes.

We consider it is appropriate for the net negative IRSR to be recovered from CNSPs - analogous to the current arrangements for negative IRSR on a radial interconnector. This ensures that SRD units never pay out negative, which would be undesirable for the reasons outlined in section 2.4.3. Although it places some risk and cost on CNSPs and consumers, recovery from CNSPs is consistent with the existing arrangements and the magnitude of the risk will be limited by clamping.

For the avoidance of doubt, the final rule will also net off IRSR in trading intervals when the total IRSR around the loop is zero. The rationale is the same as the rationale for netting in net negative cases. There would be no distribution of IRSR to SRD units (i.e. no unit payouts) and no negative IRSR to be recovered from CNSPs in this case.

We considered stakeholder feedback on netting in net negative cases

In submissions to the directions paper, CNSPs and consumer groups were supportive of the proposed approach to netting in net negative cases.[155] Transgrid noted that this would "further reduce consumer exposure to downside risk and minimise CNSP cashflow variability."[156]

Origin and Alinta Energy did not support the proposal to net off in net negative cases as they considered it would impact SRA hedging value while providing little benefit in mitigating risk for CNSPs or avoiding gaming. Both suggested that the existing arrangements should apply in net

154 Negative IRSR is reported in AEMO's Quarterly Energy Dynamics reports. This figure was drawn from AEMO, Quarterly Energy Dynamics Q4 2024, January 2025, p.45.

155 Submissions to the directions paper: ENA, p.3; Transgrid, p.3; EUAA, p.1; ECA, pp.1-2.

156 Transgrid, submission to the directions paper, p.3.

negative cases.[157] AEMO also considered the benefits of netting in net negative cases may be limited.[158] The other submissions we received did not comment on this aspect of the netting off proposal.

Origin and AEMO noted that CNSPs would not be exposed to significant risk in net negative cases because clamping would limit the magnitude of net negative IRSR.[159] The Commission acknowledges that clamping should reduce the amount of net negative IRSR, compared to unclamped net negative IRSR in net positive cases, but the risk to CNSPs and cost to consumers may still be material. AEMO's submission acknowledges that large IRSR can accrue, even on radial interconnectors, despite clamping (and that CNSPs currently manage the associated cash flow risk).[160] The amount of net negative IRSR that will arise in the loop is uncertain and could be similar to, or larger than, the negative IRSR arising on radial interconnectors. Therefore, the Commission considers it is prudent to minimise the amount of net negative IRSR recovered from CNSPs so as to mitigate the associated cash flow risks (and costs) to consumers.

Further, AEMO and Alinta Energy considered that netting off in net negative cases would not materially disincentivise gaming or mispricing.[161] AEMO argued that gaming incentives can arise regardless of whether IRSR is netted in net negative cases: "Generators with positions that can influence flow around the loop are already exposed to price dynamics across and within regions with existing incentive and ability to misprice and dispatch below their local marginal price... to access the RRP."[162] Alinta Energy made similar comments and noted that "extensive legislative and regulatory obligations" exist to discourage anti-competitive behaviour by market participants.[163] Alinta Energy considered that a netting off approach may have broader competition impacts regardless of how net negative cases are treated (see also section 2.4.5).[164] While acknowledging these points, the Commission remains of the view that failing to net off in net negative cases would risk creating a new opportunity for gaming, which would not support market efficiency or good regulatory practice.

Origin requested clarification on how netting would apply when the looped interconnectors are subject to clamping, since "negative residues on that interconnector may reduce, and the aggregate residue across the loop may become positive—while the clamp remains in place."[165] For the avoidance of doubt, if the net loop IRSR becomes positive while clamping is active, then netting based on net trade will apply as it does in all net positive cases. We do not expect that this situation would persist for long periods. According to AEMO's consultation paper on negative residue management (NRM) in transmission loops, any NRM constraints on the looped interconnectors would be removed at the end of the 30-minute period in which the net loop IRSR becomes positive (or zero).[166]

157 Submissions to the directions paper: Origin, p.10; Alinta Energy, p.4.

158 AEMO, submission to the directions paper, p.4.

159 Submissions to the directions paper: Origin, p.10; AEMO, p.4.

160 AEMO, submission to the directions paper, p.3.

161 Submissions to the directions paper: AEMO, p.4; Alinta Energy, p.4.

162 AEMO, submission to the directions paper, p.4.

163 Alinta Energy, submission to the directions paper, p.4.

164 Ibid.

165 Origin, submission to the directions paper, p.10.

166 AEMO, Consultation on automation of negative residue management for the implementation of transmission loops, consultation paper, p.12. AEMO is currently consulting on its draft report for NRM in transmissions loops: https://www.aemo.com.au/consultations/current-and-closed-consultations/automation-of-negative-residue-management-for-the-implementation-of-transmission-loops

3.2.3 How the final rule treats transmission losses and special cases

Section 3.2.1 above provides a conceptual outline of how the net trade approach will operate, with some simplifications such as ignoring transmission losses. However, these complexities must be accounted for in the detailed operation of the final rule. This section explains how the final rule takes into account transmission losses and special cases - that is, scenarios where the net trade calculation needs to be modified or clarified.

The final rule accounts for transmission losses

Interconnectors notionally connect the RRN of one region to the RRN of an adjacent region. However, some energy is lost when power flows along the interconnector, due to resistive heating and other factors. This means the amount exported from the exporting RRN is greater than the amount imported at the importing RRN.

Under the existing arrangements, transmission losses are accounted for in AEMO's methodology for the allocation and distribution of settlements residue.[167] This methodology will continue to apply for calculating the IRSR allocation for each directional interconnector. The net loop IRSR will be calculated by summing the allocations for all arms of the loop, thus the net loop IRSR accounts for losses.

For the net trade approach, further clarification on the treatment of losses is necessary to ensure that settlement balances. Because of losses, the total of the net exports from the looped regions to the rest of the loop will be slightly greater than the total of the net imports. This has implications for the net trade calculation because the net trade quantities will not add up to the correct net import or export for all regions, as they do in the simplified example in section 3.2.1.

The final rule resolves this issue by calculating the 'net trade amount' (that is, the payouts to be assigned to SRD unit holders) in three steps:

1. For each directional interconnector, the net trade quantity is multiplied by the price difference between the RRP for the importing region and the RRP for the exporting region.[168]
2. The net loop IRSR is provisionally distributed between directional interconnectors in proportion to the amount calculated in step 1.[169] The result of this step is the provisional net trade amount, which may be positive, negative or zero.
3. Finally, the net loop IRSR is distributed between directional interconnectors in proportion to the amount calculated in step 2, *where that amount is positive*.[170] The result of this step is the net trade amount following secondary netting, which is always positive or zero. This is the amount distributed to SRD unit holders.

Step 2 and 3 guarantee that settlement will balance because they only distribute to SRD unit holders the funds that are actually available - that is, the net loop IRSR. This works because AEMO already accounts for losses when calculating the net loop IRSR, based on its existing methodology. SRD unit payouts remain proportional to net trade and to the price difference between regions.

Refer to appendix E for more information.

167 AEMO, Methodology for the allocation and distribution of settlements residue (current version: version 3, published 2 June 2024), pp.5-7.

168 Clause 3.6.6(i)(2) of the Final Rule.

169 Clause 3.6.6(i) of the Final Rule.

170 Clause 3.6.6(j) of the Final Rule.

We considered how the rule would operate in special cases

We considered three types of special cases in the detailed operation of the final rule. These are outlined in Table 3.1.

Table 3.1: Treatment of special cases in the final rule

Region with zero net export	One of the looped regions may be neither net importing nor net exporting if the total flows in are equal to the total flows out. This can be understood as power flows passing through region A on the way from region B to C. Intuitively, the result is that only one arm of the loop has a net trade assigned to it (B-C). The net trade on any interconnectors connected to region A would be zero. All net loop IRSR, if positive, will be allocated to B-C SRD unit holders, or if net loop IRSR was negative, it will be recovered from CNSPs according to regional demand. The final rule gives effect to this by treating region A as a 'net exporting region' with net export equal to zero. Refer to clause 3.6.6(a) of the Final Rule (definition of 'net exporting region').
Three net exporting regions	Because of transmission losses, it is possible for all three looped regions to be net exporting in the same trading interval, as measured at the RRN. This may occur when the power flows around the loop are all clockwise (or all anti-clockwise) and of similar magnitude. We expect this would be a rare scenario as it is unlikely to be an efficient dispatch solution, but it appears to be technically possible. In such a scenario, the net loop IRSR would be small. This case needs to be accounted for operationally but the impact on SRD unit payouts would be negligible. Where there are three net exporting regions, and if the net loop IRSR is positive, the final rule assigns a net trade to each arm of the loop that is equal to the exporting region's net export, in the direction of physical flow. The net positive IRSR is then distributed based on net trade as per normal. Refer to clause 3.6.6(h) of the final rule. Secondary netting will still apply. This is the only scenario where there is 'net trade' on all three arms of the loop. If the net trade amount assigned to one arm is negative, that amount will be deducted from the other two arms in proportion to their positive net trade amounts (similar to proportional netting). If the net trade amounts assigned to two arms are negative, they are both deducted from the positive net trade amount on the third arm. Refer to clause 3.6.6(j) of the final rule.
Interconnector outages	If there is a planned or unplanned outage on one or more looped interconnectors, the remaining arms no longer behave as a loop (i.e. consistent with Kirchhoff's laws). (Where there is more than one physical link between regions, this only occurs if outages affect all links simultaneously.) AEMO has indicated in its NRM consultation paper that clamping would automatically revert to the non-loop methodology (i.e. individual interconnectors would be separately clamped) if there is an outage that takes

	one arm of the loop out of service. This means that negative IRSR on any individual arm of the loop would be limited. However, netting based on net trade will continue to apply in case of an interconnector outage. This approach will minimise complexity and avoid unintended consequences such as unpredictable outcomes for CNSPs and SRD unit holders. Due to clamping, negative IRSR on any individual arm of the loop would be limited, and so the impact of netting on SRD unit payouts would also be limited.

Source: AEMO, Consultation on automation of negative residue management for the implementation of transmission loops, consultation paper, p.13.

3.3 How cash flows to CNSPs will be allocated

Box 4: Key points

- Net negative IRSR, SRA proceeds and positive IRSR not attributed to any SRD units ('unsold IRSR') around the loop will be allocated to CNSPs as follows:
  - Net negative IRSR will be allocated to CNSPs in each region in proportion to regional demand. For the purposes of the final rule, 'regional demand' means each region's total annual electricity consumption over the prior year, calculated on a rolling basis.
  - SRA proceeds and unsold IRSR will be allocated to the CNSP in the importing region.
- This approach has been shaped by stakeholder feedback and further analysis. It strikes a balance between sharing the costs of the loop and predictability for CNSPs, while also accounting for uncertainties and practical complexities.
- This approach is the same as the proposal in the directions paper (and effectively the same as the draft determination).
- This approach applies only to looped interconnectors (that is, it does not change the allocation approach for radial interconnectors).

Under the final rule, CNSP cash flows for transmission loops will be allocated using two different methods. That is:

- Negative cash flows (net negative IRSR) will be recovered from CNSPs in each looped region in proportion to regional demand.[171] This is discussed in further detail in section 3.3.2 and section 3.3.3.
- Positive cash flows (SRA proceeds and unsold IRSR) will be distributed to the CNSP in the importing region.[172] This is discussed further in section 3.3.4.

This is the same as the proposal in the directions paper (and effectively the same as the draft determination) and strikes a balance between sharing the costs of the loop, predictability for CNSPs, and implementation feasibility. Our reasons are effectively the same as in the directions paper, however, stakeholder feedback and further analysis informed our decision to maintain the

171 Clauses 3.6.5(c) and 3.6.6(c) of the Final Rule.

172 Clauses 3.18.4(a) and 3.6.6(b)(3), respectively, of the Final Rule.

approach.[173] This approach could be reviewed in a future review of IRSR arrangements - refer to chapter 5.

On radial interconnectors,[174] these cash flows are all allocated to the CNSP for the importing region. The final rule only applies to looped interconnectors and so it does not change the allocation approach for radial interconnectors.[175]

3.3.1 CNSPs are exposed to positive and negative cash flows around the loop, which are passed through to consumers

As discussed in chapter 4 of the directions paper, CNSPs are exposed to both positive and negative cash flows resulting from IRSR arising around the loop, which are passed through to consumers via reductions and increases in transmission prices, respectively. These amounts are:

- **Net negative IRSR.** Net negative IRSR is a variable amount which is unknown in advance and is allocated to CNSPs for payment. Both netting and clamping will minimise the magnitude of negative IRSR. However, there is still a risk that material negative IRSR could arise in net negative cases. The amount of negative IRSR payable by CNSPs to AEMO is recovered directly from consumers through transmission pricing.[176]
- **SRA proceeds.** CNSPs receive SRA proceeds, which are positive amounts resulting from the sale of SRD units in the SRA. Generally, for any financial year, approximately 80 per cent of SRA proceeds are known to CNSPs in advance of setting transmission prices for that year. A forecast amount of SRA proceeds is used to reduce transmission prices, with adjustments for actuals in subsequent pricing years.[177]
- **Unsold IRSR.**[178] CNSPs receive positive IRSR not attributed to an SRD agreement. This positive IRSR is a variable positive cash flow which is unknown in advance. A forecast amount of unsold IRSR is used to reduce transmission prices, with adjustments for actuals in subsequent pricing years.[179]

CNSPs need to forecast these cash flows in advance in order to set transmission prices on an annual basis. We have accounted for this in considering the predictability of the approach to allocating these cash flows (refer to section 3.3.2 below for further information), however, we understand that CNSPs are likely to have remaining concerns about their ability to forecast these cash flows in the year before, and for several years after, PEC's commencement. We discuss these concerns in more detail in chapter 4.

3.3.2 The final rule will share net negative IRSR by regional demand

The final rule allocates net negative IRSR to CNSPs in each region in proportion to regional demand.[180] 'Regional demand' means each region's total annual electricity consumption over the prior year, and will be calculated on a rolling basis.

173 Refer to chapter 4 of the directions paper.

174 In clause 3.6.6 of the Final Rule these are referred to as directional interconnectors that are not looped interconnectors.

175 See clauses 3.6.6(d)(3) and (e) and 3.18.4(a) of the Final Rule. These clauses of the Final Rule retain the substance of the equivalent former provisions of the NER, although they were amended as part of the Final Rule to align with the new structure and terminology of the Final Rule.

176 Clause 6A.23.3(e) of the Final Rule.

177 Clause 6A.23.3(b)(1) of the Final Rule and clause 6A.23.3(f) of the NER.

178 In the directions paper, we referred to this cash flow as 'unsold SRD units'. We have refined this terminology for the purpose of the final determination as it is the positive IRSR amount not attributed to any SRD agreement that is allocated to CNSPs, not the SRD unit itself.

179 Clause 6A.23.3(b)(1) of the Final Rule and clause 6A.23.3(f) of the NER.

180 This is termed 'regional share' in the Final Rule and is defined in clause 3.6.6(a) of the Final Rule.

The Commission considers this approach to sharing net negative IRSR best shares the costs of the loop between the three regions' consumers. It is also a comparatively stable approach compared with other options, which will assist CNSPs with forecasting negative cash flows.

This approach is the same as the approach proposed in the directions paper,[181] and is essentially the same as the draft rule.[182] Note that netting off in net negative cases, as described in section 3.2.2, means that there will be less total IRSR recovered from CNSPs under the final rule than there would be under the draft rule.

Allocation by regional demand is different to the approach for allocating negative IRSR on radial interconnectors under the NER and the approach in AEMO's rule change request. AEMO proposed that the current Rules would continue to apply when the net loop IRSR is negative, so that all negative IRSR in those trading intervals would be allocated to the CNSP in the importing region.[183] We consider that allocating net negative IRSR based on regional demand is likely to better contribute to the achievement of the NEO than the proposed rule because it reduces the volatility to which CNSPs and consumers are exposed, and allocates costs and risks appropriately between regions (see section 2.4.2).

Stakeholders generally supported sharing net negative IRSR by regional demand

In response to the directions paper, ECA, Energy Users Association of Australia (EUAA), ENA and Stanwell supported the allocation of net negative IRSR by regional demand, noting that it would spread costs fairly between consumers.[184] Transgrid and Shell Energy noted the potential for this to lead to inequitable outcomes or favour smaller regions over larger regions.[185] Transgrid identified that NSW would be allocated approximately 55% of the net negative IRSR when shared by regional demand. It considered this may warrant a review in future.

These views shaped our decision to maintain the approach in the directions paper for the final rule, that is, to share net negative IRSR between CNSPs based on regional demand share.

We consider that it is not clear the extent to which each region benefits from the loop - and therefore, it is not clear the extent to which each region should bear the costs of net negative IRSR. Net negative IRSR may be material, despite netting and clamping, so a decision to allocate to the importing region (as is the status quo) is not necessarily justified compared with sharing the costs proportionally to regional demand. We also note that a regional demand approach for net negative IRSR is feasible from an implementation perspective.

We recommend reviewing the arrangements for allocating net negative IRSR as part of a future review (refer to chapter 5).

Stakeholders suggested refining the approach to calculating regional demand share

The directions paper proposed calculating the regional demand share based on a region's total annual electricity consumption for the past 52 weeks, recalculated for each billing period on a rolling basis. This was the same calculation approach proposed in the draft determination.

In response to the directions paper:

181 Refer to chapter 4 of the directions paper, p.38.

182 Refer to section 3.2 of the draft determination, p.17.

183 AEMO, rule change request, p.15.

184 Submissions to the directions paper: ECA, pp.1-2; EUAA, p.1; ENA, p.2; Stanwell, p.2.

185 Submissions to the directions paper: Transgrid, p.3; Shell Energy, p.3.

- AEMO suggested using weekly regional demand rather than rolling annual regional demand. It considered this would be a less resource-intensive calculation that is unlikely to be materially different from an annual value and may be more reflective of inter-regional price dynamics.[186]
- Shell Energy and the EUAA suggested using regional demand for each trading interval to calculate the regional demand share. Shell Energy considered that calculating regional demand on an annual basis was inconsistent with netting IRSR on an interval-by-interval basis.[187]
- ENA suggested using the regional demand figure calculated for the National Transmission Planner (NTP) fee determinations, which is based on consumption in a region in the prior financial year as a proportion of the total consumption across the relevant regions in that financial year. This is already determined once each year by AEMO, rather than on a rolling basis.[188] It considered that the rolling figure had a "false sense of preciseness", while the NTP fee figure would be more stable and predictable for CNSPs forecasting net negative IRSR allocation.[189]

We maintained the same approach to calculating regional demand share to balance stable outcomes with ease of implementation

We analysed the impact of different calculation methods on the stability and predictability of each region's share of regional demand. Refer to Table 3.2 below.

Table 3.2: Comparison of regional demand on a weekly or annual basis

	SA	Vic	NSW
Differences in the shares of weekly regional demand			
Maximum	12%	37%	61%
Minimum	8%	31%	53%
Standard deviation	0.6%	1.3%	1.6%
Differences in the shares of rolling annual regional demand			
Maximum	10%	35%	56%
Minimum	9%	34%	55%
Standard deviation	0.1%	0.2%	0.3%

Source: This analysis uses operational demand data from the 2022-23 and 2023-24 financial years.

This analysis suggests that:

- annual regional demand is a more stable figure than weekly, as suggested by AEMO (or by trading interval, as suggested by Shell Energy). It is also unclear if a weekly or interval-by-interval basis would be more reflective of inter-regional price dynamics until the loop is in operation.
- the difference in stability is marginal between fixed annual regional demand, as suggested by ENA, and rolling annual regional demand, which was the directions paper approach.

186 AEMO, submission to the directions paper, p.5.

187 Submissions to the directions paper: Shell Energy, p.3; EUAA, p.3.

188 Under AEMO's function as the NTP for the NEM, "NTP fees are calculated and apportioned using the gigawatt hours (GWh) consumed in a region in the prior financial year as a proportion of the GWh consumed in all regions in that financial year. AEMO is required to publish these costs by 15 February each year". Refer to www.aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2025/fy26-ntp-fees.pdf for details of the 2025-26 financial year determination.

189 ENA, submission to the directions paper, pp.5-6.

While AEMO's determination of participant fees, including NTP function fees, are prescribed in the Rules, the NTP fee allocation figure suggested by ENA is not.[190] It is therefore undesirable to tie the calculation process for the purpose of this final rule to the NTP fee figure because if the method for calculating the NTP fee figure were to change in the future, this would impact this rule.

As such, we opted to maintain the rolling annual demand calculation for the final rule as it represents a reasonable compromise that will not impede CNSPs' ability to forecast negative IRSR and is reasonably simple for AEMO to calculate.

3.3.3 How the regional demand calculation works

Under the final rule, the CNSP for each region of the loop will be allocated the net negative IRSR in a trading interval multiplied by its 'regional share'.[191]

Regional share is defined as rolling annual regional demand

A 'regional share' is defined in clause 3.6.6(a) of the final rule as the ratio of a region's rolling annual demand and the rolling annual regional demand for the three regions forming the loop.

> Regional share = Annual regional demand (ARD) / Total regional demand for the looped regions (TRD)

Annual regional demand (ARD) is the rolling annual regional demand of the region for the billing period, which means the total electrical energy consumed by a region in a year. This is calculated as adjusted consumed energy (ACE) for the region for the past 52 weeks on a rolling basis.[192] That is, for each billing period (week), regional demand will equal ACE summed across:

- all trading intervals within that billing period and the previous 51 billing periods, and
- all market connection points in the region.

ACE is defined in the NER.[193] In plain language, ACE for a market connection point is the amount of electrical energy consumed by that market connection point, and where applicable, adjusted for distribution losses and unaccounted for energy.

Total regional demand (TRD) means the sum of annual regional demand for all looped regions.[194]

This approach to calculating a CNSP's regional share is the same as in the draft rule and the directions paper.[195]

3.3.4 The final rule will continue to allocate SRA proceeds and unsold IRSR to the importing region

The final rule allocates SRA proceeds and unsold IRSR to the importing region's CNSP.[196] While we considered allocating these cash flows in the same way as net negative IRSR (that is, by regional demand), this would require complex system changes by AEMO for an uncertain benefit.

190 See clause 2.11.1(c)(5A) of the NER. The NTP function fees were, for a time, based on a regional demand basis set out in the Rules, but this was as a transitional arrangement under clause 11.130.1 of the NER.

191 That is, where the 'net loop allocation' for a trading interval is negative, the amount recovered from the CNSP in each region is the product of the 'net loop allocation' and the 'regional share' for the billing period in which the trading interval occurs. See clause 3.6.6(c) of the Final Rule.

192 See the definition of 'ARD' in the definition of 'regional share' in clause 3.6.6(a) of the Final Rule.

193 Clause 3.15.4(a) and (b) of the NER.

194 See the definition of 'TRD' in the definition of 'regional share' in clause 3.6.6(a) of the Final Rule.

195 Refer to section 3.2.1 of the draft determination, pp.17-18, and to section 4.2 of the directions paper, pp.39-40.

196 Clause 3.18.4(a) and 3.6.6(b)(3), respectively, of the Final Rule.

Therefore, we have maintained the same approach proposed in the directions paper,[197] which is also effectively the same as the draft rule[198] and the rule change proposal.[199] It is also the same as the current approach in the Rules for radial interconnectors.[200]

For the allocation of SRA proceeds to the importing CNSP, the importing region is determined by the SRD unit category. For example, all proceeds from the sale of units in the SA-NSW category will be allocated to the NSW CNSP, since SA-NSW units reflect net energy transfer from SA into NSW under the net trade approach. The SRA proceeds would reflect the expected payouts (i.e. to unit holders) and hedging value of the units based on the net trade approach. The allocation of unsold IRSR to the importing region's CNSP is also based on net trade. For example, any part of the net trade amount assigned to SA-NSW for which an SRD unit is not sold will be allocated to the NSW CNSP.

Some stakeholders considered that all cash flows to CNSPs should be treated in the same way

In response to the directions paper, ENA and Transgrid supported the Commission's approach to allocate SRA proceeds and unsold IRSR to the importing region, given the complexity of allocating these cash flows by regional demand. Transgrid also noted it supports treating unsold IRSR in the same way as SRA proceeds.[201]

EUAA and Shell Energy both did not agree with the Commission and considered that SRA proceeds and unsold IRSR should be allocated in the same way as net negative IRSR (that is, all cash flows should be allocated by regional demand). They considered that treating all cash flows in the same way would better balance the payment of costs with the benefits of the loop.[202]

We also sought feedback from CNSPs on whether treating these cash flows in different ways would impact their capacity to pay.[203] This was in response to a comment from AEMO in its submission to the draft rule, which questioned this.[204] CNSPs did not specifically address this in their submissions to the draft determination (beyond supporting the Commission's proposed approach to allocating all cash flows); however, had broader cash flow forecasting concerns that are discussed in chapter 4.

We maintain our reasoning for treating these cash flows differently

In section 4.3.1 of the directions paper,[205] we discussed that the benefits of allocating SRA proceeds and unsold IRSR by regional demand are uncertain, and unlikely to outweigh the implementation costs. This is because it is difficult to make assumptions about where the costs and benefits fall without seeing the loop in operation, as the arms of the loop are interdependent. We also understand that allocating SRA proceeds and unsold IRSR by regional demand would require complex changes to AEMO's SRA systems.[206] This may incur costs and potentially delay other important systems updates for what we consider is an uncertain benefit.

197 Refer to chapter 4 of the directions paper.

198 Refer to section 3.2 of the draft determination.

199 AEMO's rule change request only proposed changes to the allocation of negative IRSR. Refer to the rule change request, p.5.

200 Clause 3.18.4(a) of the NER.

201 Submissions to the directions paper: ENA, p.1; Transgrid, p.3.

202 Submissions to the directions paper: EUAA, p.3; Shell Energy, p.3.

203 Refer to the directions paper, p.42.

204 AEMO, submission to the draft determination, p.3.

205 Refer to directions paper, p.41.

206 The SRA system is separate from the settlements system, which calculates the positive and negative IRSR weekly and is where the majority of the changes due to netting will be made.

Our view is unchanged from the directions paper. We acknowledge the views provided by some stakeholders that it would be more beneficial to treat all cash flows in the same way, however we maintain that without operational experience and data, the benefits of allocating these cash flows by regional demand are uncertain. We also note that the risk profile of these cash flows is different to that of negative IRSR. To the extent that SRD units are sold,[207] positive cash flows are in the form of SRA proceeds, which are predictable and thus do not present the same risks and costs to consumers.

However, we note that this is another instance of the underlying uncertainty of future loop operations. Therefore, we consider that this could be reviewed in a future review of IRSR arrangements - refer to chapter 5.

3.4 The final rule includes comprehensive reporting requirements

Box 5: Key points

- The final rule expands the requirements for AEMO to report on IRSR and SRA outcomes.
- We consider these reporting requirements will promote transparency by enabling all stakeholders to access detailed, timely information about the operation of the transmission loop, netting, and SRAs.
- The final rule maintains the existing requirements for AEMO to report on auction clearing prices, proceeds, and bids, as well as total settlements residue, IRSR on individual interconnectors, and intra-regional settlements residue for each billing period.
- The final rule introduces new requirements for AEMO to report on:
  - secondary trading of SRD units and any terminations of SRD units
  - SRD unit payouts based on net trade, and what the total payouts would have been without secondary netting, for each unit category in each billing period
  - the amount of negative IRSR that is recovered from CNSPs in each billing period
- The final rule also introduces requirements for AEMO to report certain information on a trading interval basis, including the IRSR assigned to each directional interconnector under AEMO's existing methodology, and some intermediate steps in calculating the SRD unit payouts based on net trade.
- These reporting requirements are an extension of what we proposed in the directions paper, and are more extensive than the draft rule, which only included one additional reporting requirement.
- Some of the new requirements only apply to the loop while others apply across the NEM for consistency.

3.4.1 Comprehensive reporting requirements will promote transparency of the new arrangements

The final rule includes expanded reporting requirements for AEMO to publish a range of information about IRSR and SRA outcomes. These requirements build on the directions paper proposal and include information to be reported on a quarterly, billing period, and trading interval basis. Section 3.4.2 explains the reporting arrangements in more detail.

207 We discuss our view that SRD units would likely be sold even if payouts are uncertain or expected to be low in section 2.4.5.

The Commission considers that the final rule reporting requirements will promote transparency by enabling all stakeholders to access detailed, timely information about IRSR outcomes in the transmission loop. Market participants will be able to use this information to inform trading decisions. CNSPs can use the information to help inform forecasts of net negative IRSR, SRA proceeds, and unsold IRSR for setting transmission prices, as well as managing cash flows on a shorter timescale. It will also provide a data source for quantitative analysis of loop outcomes and whether the final rule is operating as intended, for example as part of a future AEMC review (see chapter 5).

Most of the new reporting requirements are only relevant to the loop, but some will also apply to non-looped interconnectors. This appropriately provides for consistent reporting by AEMO across all regulated interconnectors, SRD unit categories, and NEM regions.

The expanded reporting requirements will also help address some concerns stakeholders raised about the complexity of netting and potential unpredictable outcomes. Several submissions to the directions paper noted that netting off would introduce complexity to the framework. With either proportional netting or the net trade approach, SRD unit payouts would depend on prices and power flows all around the loop, not just on one arm.[208] CNSPs also noted that uncertainty about the extent to which affected SRD units would be terminated and re-auctioned would impact their ability to forecast SRA proceeds for the year ahead (amongst other concerns, discussed in chapter 4)[209] Stakeholders did not comment explicitly on the reporting requirements that we proposed in the directions paper.[210]

AEMO's rule change request did not propose any new reporting arrangements.[211] We therefore consider the final rule is likely to better contribute to the achievement of the NEO than the proposed rule because the reporting requirements in the final rule promote the NEO by aligning with principles of good regulatory practice, including transparency (see section 2.4.4).

3.4.2 We have expanded IRSR and SRA reporting requirements in the final rule

Information to be included in quarterly SRA reports

The final rule requires AEMO to include in its quarterly SRA reports the following information for each SRD unit category:

1. The auction clearing prices and auction proceeds[212]
2. All bids, without identifying bidders[213]
3. Details of any SRD units that were terminated since the last auction, including the number of units, unit category, and issue price.[214]
4. The total number of SRD units sold, and of those, how many were offered under the secondary trading arrangements.[215]

These requirements are the same as we proposed in the directions paper. The first two items are existing requirements under the NER and the third and fourth are new requirements. AEMO will be required to make this information available to registered participants as soon as practicable after

208 Submissions to the directions paper: ENGIE, p.2; AEC, p.1.
209 Submissions to the directions paper: Transgrid, pp.4-5; ENA, pp.4-5.
210 Refer to section 3.4.3 of the directions paper, pp.35-36.
211 AEMO, rule change request, pp.15-17.
212 Clause 3.13.5A(a)(1) and (3) of the Final Rule.
213 Clause 3.13.5A(a)(2) of the Final Rule.
214 Clause 3.13.5A(b1) of the Final Rule.
215 Clause 3.13.5A(a)(4) of the Final Rule.

each auction. AEMO's current practice is to make quarterly SRA reports publicly available on its website.[216]

We decided to include information about terminated SRD units because it is possible that the introduction of netting with the final rule will result in SRD unit holders choosing to terminate previously-purchased units in accordance with any rights they may have under the auction participation agreement. Reporting on terminated SRD units - like the existing SRA reporting requirements - will apply to all SRD unit categories (i.e. corresponding to directional interconnectors both in the loop and outside it). We discuss considerations surrounding the termination of SRD units resulting from the introduction of netting in section 4.3.4.

Information to be reported for each billing period

The final rule will require AEMO to report, for each billing period (week):[217]

1. The total settlements residue, including both inter-regional and intra-regional settlements residue
2. The amount of IRSR assigned to each directional interconnector, according to AEMO's methodology
3. The amount of intra-regional settlements residue attributed to each region
4. For each SRD unit category, the payment per unit on account of settlements residue (but not who received the payments)
5. For each SRD unit category, what the total pool of payouts would have been without secondary netting (termed the 'provisional net trade amount' in the final rule)
6. The amount of IRSR that is to be recovered from each CNSP.

AEMO will be required to make this information available to registered participants as soon as practicable after final statements for each billing period. We assume that AEMO would meet this requirement through its existing settlement reports system. The first three items are existing requirements under the NER and the fourth, fifth and sixth are new requirements.

These requirements are broadly similar to those in our directions paper proposal. Because we have moved to a net trade approach for the final rule, the payment per unit (item four) will be calculated based on net trade for the SRD unit categories corresponding to looped interconnectors. We have also added reporting of the provisional net trade amount (item five) for the final rule to provide information to market participants on how SRA outcomes would be affected if secondary netting was not applied. There may be an opportunity for market participants to establish contracts trading the negative amounts deducted by secondary netting, using this data (see appendix B for more information).

Some of these new requirements will apply outside the loop. Reporting of the payout per unit (item four) will also apply to non-looped interconnectors for which SRD units are sold. For those unit categories, the payment per unit on account of settlements residue will be determined by the existing arrangements, not net trade. Reporting of provisional net trade amounts (item five) will only apply in the loop, while reporting of IRSR recoverable from CNSPs (item six) will apply for the CNSP in every NEM region. Item six was the only new reporting requirement that was included in the draft rule.[218]

216 AEMO, Settlement residue auction reports, https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/settlement-residue-auction-reports.

217 Clause 3.13.5A(b) of the Final Rule.

218 Clause 3.13.5A(b)(4) of the Draft Rule.
Refer to section 3.5 of the draft determination, p.35.

Information to be reported for each trading interval

The final rule requires AEMO to publish, for each trading interval:

1. for each looped region, the net regional export quantity.[219]
2. for each directional interconnector in the NEM, the allocation, which may be positive, negative or zero.[220]
3. for each directional interconnector in the transmission loop:[221]
    a. the net trade quantity, in megawatt hours (MWh)
    b. what the total of SRD unit payouts for the relevant unit category would have been without secondary netting (termed the 'provisional net trade amount' in the final rule)
    c. the total of SRD unit payouts for the relevant unit category, based on net trade (termed the 'net trade amount' in the final rule).

These quantities are used in the calculation of SRD unit payouts based on net trade and may be useful to market participants in understanding the net trade approach, or understanding loop operation in detail.

AEMO will be required to publish this information for each trading interval by the following trading day, in accordance with the spot market operations timetable.[222] This aligns with AEMO's existing obligations to publish RRPs, inter-regional loss factors and other information under NER clause 3.13.4(n). We expect that AEMO would publish the information in its Market Management System (MMS) data model, which is current practice for the information in the existing clause 3.13.4(n). AEMO already publishes the IRSR attributed to each directional interconnector in each trading interval (item two above) in the MMS data model, so the final rule formalises this practice.

The draft rule and the directions paper proposal did not include reporting requirements on a trading interval basis. We have added these requirements for the final rule because we consider that the provision of detailed information on IRSR outcomes, closer to the time they occur, will assist market participants in understanding how the loop impacts market outcomes.

219 Clauses 3.13.4(n) and 3.6.6(k)(1) of the Final Rule.

220 Clauses 3.13.4(n), 3.6.6(k)(2) and 3.6.5(a)(1) of the Final Rule.

221 Clauses 3.13.4(n) and 3.6.6(k)(3) of the Final Rule.

222 AEMO must publish the spot market operations timetable under NER clause 3.4.3. https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/spot-market-operations-timetable.pdf

4 Commencement and transitional arrangements

Box 6: Key points

- The final rule will commence on 2 October 2025, however, PEC will not be operational until approximately one year after this date.
- The final rule clarifies the arrangements over the transitional period using two key dates that correspond to two key implementation activities that need to occur:
  - The loop needs to be represented in AEMO's dispatch systems. The go-live date for these changes is the 'loop operations start date' - which needs to be on or after 1 October 2026 and no later than 2 November 2026.
  - AEMO's settlement systems need to be updated to implement the final rule. The go-live date for these changes is the 'loop settlements start date' – which needs to be on or after the 'loop operations start date', but no later than 2 November 2026. On and from the 'loop settlements start date', the new IRSR settlement arrangements which implement the netting off approach - outlined in chapter 3 - will apply.
- For any period between those two dates, the arrangements for the allocation and distribution of IRSR for radial interconnectors will apply to the loop. The radial arrangements will also apply before 'loop settlements start date' (as there will be no transmission loop in dispatch prior to then).
- AEMO must use reasonable endeavours to ensure that SA-NSW and NSW-SA SRD units are established under the auction rules and at least one auction is held to offer those units on or before 1 October 2026.
- AEMO must publish information relevant to the loop transition as soon as practicable, and keep this information up to date.
- These arrangements are intended to work together. They provide market participants and CNSPs with clarity on the transition to the loop while retaining flexibility for AEMO and the SRC to implement and test the loop and make changes to accommodate new SRD units.
- We worked with closely with AEMO to develop these arrangements, through ongoing bi-lateral meetings.
- The final rule does not change the way in which IRSR is distributed for radial interconnectors.

In this chapter:

- Section 4.1 outlines the commencement arrangements for the final rule
- Section 4.2 outlines the requirement to auction NSW-SA and SA-NSW units ahead of loop commencement
- Section 4.3 outlines the reporting arrangements to keep the market informed of the transition to the loop.

4.1 The final rule will commence on 2 October 2025, with netting commencing between 1 October 2026 and 2 November 2026

The final rule commences (is consolidated in the NER) on 2 October 2025.[223] PEC will not yet be operational at this time, and therefore an inter-regional transmission 'loop' will not yet exist in dispatch.[224]

There are two key elements to the transitional arrangements in the final rule to manage the transition to PEC's operation:[225]

- The loop must be represented in AEMO's dispatch systems no earlier than 1 October 2026 (the **'loop operations start date'**).[226] AEMO has advised that this is when it intends to include the loop in dispatch. Loop flows (and therefore the spring washer effect) will impact market dispatch from this time. The 'loop operations start date' must occur by no later than 2 November 2026 (see below).
- The new IRSR settlement arrangements - which implement the netting off approach - must go live in AEMO's settlement systems by no later than 2 November 2026 (the **'loop settlements start date'**). This allows a limited period (of maximum one month) for AEMO to test loop dispatch before implementing changes to its settlement systems.

The final rule defines a **'loop transition period'** as any period between the 'loop operations start date' and the 'loop settlements start date'. During this period (if any), the rules for the allocation and distribution of IRSR for radial interconnectors will apply to the loop.[227]

4.1.1 We developed this approach to account for the timings of AEMO's systems implementation

We have worked closely with AEMO to develop this approach, taking into consideration their feedback in response to the directions paper[228] as well as their ongoing feedback and advice about the technical considerations for transitioning to the loop and implementation of the final rule. AEMO has advised us that this approach is required to accommodate its implementation and testing timelines for the transition to loop operation.

AEMO also advised us that there are two key implementation steps, which cannot occur on the same day:

- Representing PEC in the NEM dispatch engine (NEMDE) as a loop (and implementing the new approach to clamping, where it is only applied in net negative cases) requires changes to AEMO's dispatch systems. Under AEMO's implementation timelines, the earliest date for loop representation in NEMDE is 1 October 2026, and these changes will need to be tested before changes are made to settlement systems.

223 Refer to transitional clause 11.188.1, definition of 'commencement date'.

224 AEMO explains what it means for PEC to become operational in AEMO's PEC Market Integration Papers, Final report, February 2024, p.15, available at aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/pec-market-integration-paper/february-2024/final-paper-pec-market-integration.pdf?la=en. AEMO is currently operating Stage 1 of the PEC interconnector using a micro-slice approach. The micro-slice "inserts a small Victoria region interfaced between the New South Wales and South Australia regions model... AEMO notes the micro-slice option retains the radial (i.e., no loops) network topology of the current network.". When PEC becomes operational, it will be considered as a separate line ("interconnector") and the 'loop' network topology will commence.

225 These elements are set out in the definitions included in clause 11.188.1 of the Final Rule. The timing for each of these elements is set out in clause 11.188.4(a) and (b) of the Final Rule.

226 This is also the date that PEC becomes a regulated interconnector as per the amended definition of 'regulated interconnector', paragraph (c), in Chapter 10. This is clarified in clause 11.188.4(c) of the Final Rule.

227 Clause 11.188.4(d) of the Final Rule.

228 AEMO, submission to the directions paper, pp.5-6.

- Calculating and distributing IRSR for a loop in accordance with the final rule requires changes to AEMO's settlement systems. Under AEMO's implementation timelines, the latest date for settlement system changes to go live is 2 November 2026.

This meant we needed to refine and clarify our approach to commencement and transition from the directions paper and draft determination approaches, both of which required the two implementation activities to occur on the same day:

- In the directions paper, we proposed that the rules for the loop would take effect when the loop begins to operate. This would have been achieved through a transitional provision that defined a 'PEC operational date'.[229] The existing rules would apply prior to the 'PEC operational date' and any rule made under the directions paper proposal would apply after that date.[230]
- The directions paper approach was intended to add clarity to the draft determination - section 3.1.1 and 3.1.2 of the draft determination defined the transmission loop and used the formation of the transmission loop as the basis for when the draft rule would take effect,[231] but it did not clearly specify how the new concept of a 'loop' applied in relation to PEC.

This approach also provides greater clarity on the transition to loop operation.

Several submissions to the directions paper requested greater clarity on the loop commencement dates:[232]

- Transgrid and ENA requested clarity on the PEC operational date and how it would be triggered, with Transgrid preferring a fixed date in the Rules.
- AEMO suggested that, given the uncertainty associated with the commissioning of PEC that the rule includes a fixed, 'not before' date to allow for AEMO to plan and implement changes appropriately.

As well as clarity on commencement dates, we consider that market participants and CNSPs will benefit from further clarity on the transition to loop operation as these arrangements will inform market participant hedging decisions and CNSP forecasting, which we consider is achieved by clarifying the steps for loop commencement.

4.1.2 Settlement will use the rules for radial interconnectors during the loop transition period

The final rule provides arrangements for the directional interconnectors forming the loop to be settled under the rules that apply to radial interconnectors during the 'loop transition period' (if any). That is, they will not be settled under the new rules that apply to looped interconnectors for this period.[233]

This means, for any given trading interval:

- positive IRSR will be distributed to any relevant SRD unit holders to the extent of the unit entitlement,[234]
- any unsold IRSR (including any IRSR accruing on directional interconnectors for which there are no SRD units) will be allocated to the importing region's CNSP,[235] and

229 Refer to the indicative drafting for the directions paper, clause 11.[XXX].1, definition of 'PEC operational date'.

230 Refer to section 3.4 of the directions paper, pp.34-37, for further details on the transitional arrangements proposed for the loop under the directions paper approach.

231 Refer to the draft determination, pp.13-15 and paragraph (c)(2) in the draft rule's definition of 'regulated interconnector'.

232 Submissions to the directions paper: ENA, p.4; Transgrid, p.4; AEMO, pp.5-6.

233 Clause 11.188.4(d) and (e) of the Final Rule.

234 Clause 3.6.6(d)(2) of the Final Rule. This was formerly under clauses 3.6.5(a)(2) and 3.18.1(d) of the NER.

235 Clause 3.6.6(d)(3) of the Final Rule. This was formerly under clause 3.18.4(a)(2) of the NER. For example, if new SA-NSW and NSW-SA unit categories are not created before this time, the settlements residue associated with those directional interconnectors would be distributed to the relevant CNSP.

- negative IRSR is recovered from the importing region's CNSP.[236]

AEMO has informed us that this is possible.

We have imposed a time limit to the loop transition period to manage the risks

We acknowledge that this approach to settlement in the loop transition period brings about the possibility of significant, negative IRSR arising on the looped interconnectors while loop testing is taking place because the netting rules will not be in place. AEMO has advised that it will be clamping the loop based on the new methodology - which is only applied in net negative cases - as this also requires testing in dispatch.

This is the issue that prompted this rule change request and means CNSPs may be exposed to cash flow risks from significant, negative IRSR during this period, as all negative IRSR will be allocated to the importing region's CNSP.

We cannot be sure if this situation will arise or what its impact will be. Several factors may limit its impact:

- AEMO has advised that it will be testing loop operation in the first instance, which may limit flows on the interconnector.[237] Based on our understanding of loop flows, this may limit the amount of negative IRSR arising during this period.
- Loop operation is expected to be more efficient than the micro-slice,[238] and therefore benefits to consumers in connected regions should begin to be realised from the loop commencement date.

Nonetheless, to mitigate this risk, our approach to the transitional arrangements imposes a strict time limit on the amount of time that this situation may be able to arise.

We considered revising settlement outcomes after the loop transition period, but this would not adequately address the risks

We considered whether IRSR outcomes for the month of October should be re-calculated after the loop settlement start date, such that settlement outcomes would be revised through AEMO's routine settlement revisions process.[239] This would mean that:

- SRD unit holders would have to pay back any un-netted IRSR attributed to their units for the relevant billing periods occurring in the month of October.
- CNSPs would be repaid any un-netted negative IRSR amount already attributed to them.

Importantly, performing this revision would not solve the cash flow risks to CNSPs, as negative IRSR amounts need to be paid by CNSPs to AEMO for the impacted billing cycles.[240] It is also not possible to simply waive payment by CNSPs as the amounts payable by CNSPs for negative IRSR are required to fund the payments made to SRD unit holders.

We also consider that the implementation complexity and risks of this approach would outweigh the benefits. In particular:

- It may cause prudential issues for SRD unit holders, who would have to pay back money due to receiving un-netted positive IRSR.

236 Clause 3.6.6(e) of the Final Rule. This was formerly under clause 3.6.5(a)(4) of the NER.

237 The current schedule for hold point testing on PEC is published here: https://www.projectenergyconnect.com.au/.

238 As discussed in AEMO, PEC Implementation Final report, 9 February 2024, p.5 and p.40.

239 As that process would be amended under the National Electricity Amendment (Shortening the settlement cycle) Rule 2024 No. 22.

240 Based on AEMO's settlement cycles (refer to www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/prudentials-and-payments/settlement-calendars), the transitional settlement arrangements will most likely impact payments being made at the end of October and start of November.

- Reporting for this period would be an incorrect amount and would need to be corrected.

4.2 AEMO must use reasonable endeavours to conduct at least one auction by Q3 2026

New SRD units need to be created and auctioned for both directions of the NSW-SA arm of the loop. This process will require amendments to the auction rules, which set out the available unit categories.[241]

The final rule includes an obligation on AEMO to use reasonable endeavours to establish new SRD units under the auction rules for SA-NSW and NSW-SA and to conduct at least one auction to offer those units on or before 1 October 2026.[242] This provides some certainty for market participants managing inter-regional price risks and CNSPs forecasting cash flows.

4.2.1 It is critical that these units are auctioned as a matter of priority, however, we have provided flexibility in this requirement to manage practical considerations

The Commission considers that units on the SA-NSW and NSW-SA directional interconnectors should be auctioned as a matter of priority, that is, as far in advance of loop representation in NEMDE as possible. The reasons for this are:

- In response to the directions paper, market participants underlined the importance of SRD units for hedging inter-regional price risks (refer to chapter 2 and chapter 3 for further information on this feedback). These units will be a critical component of participant hedging strategies around the loop.
- In response to the directions paper, CNSPs suggested that PEC units should be sold as soon as possible. Uncertainties in the arrangements and outcomes of the SRA for these units create forecasting challenges for CNSPs, which could lead to cash flow risks for CNSPs and increased costs to consumers.
- There is no published information currently available on when or how these units will begin to be auctioned.

In making these arrangements, the Commission has accounted for how AEMO and the SRC work together on establishing and auctioning new units:

- Amendments to the auction rules are made by AEMO and require approval of the SRC.[243] However, given the importance of these new units being established, we have made a transitional rule that allows AEMO to make amendments to the auction rules without the approval of the SRC for this purpose.[244]
- We have made the obligation on AEMO to establish the units and conduct an auction ahead of the loop's commencement a "reasonable endeavours" requirement to account for any practical implementation challenges that may arise.
- The date we have specified for auctioning these units ("on or before 1 October 2026") has been informed by information from AEMO. This balances the need to provide AEMO with enough time to develop the necessary arrangements to auction these new units with the benefits of auctioning them before the loop commences.

241 Refer to AEMO, Settlement residue auction rules, section 4.2.

242 Clause 11.188.2(a) of the Final Rule.

243 Clause 3.18.3 of the NER.

244 Clause 11.188.2(c)(2) of the Final Rule.

We also acknowledge that it has been difficult to auction these units while the rule change process has been underway and there has been uncertainty over the final rule approach. Nonetheless, we urge these units to be established and auctioned at the first possible instance for the reasons set out above.

4.2.2 AEMO and the SRC should consider (and publish) how SA-NSW and NSW-SA units will be auctioned

In addition to conducting an auction as soon as possible, we also recommend AEMO and the SRC consider, and publish information about, timetables and volumes for auctions of SA-NSW and NSW-SA units.

Typically, for each directional interconnector, residues for a given quarter are auctioned off over 12 quarterly auctions over 3 years, each with equal quantities.[245]

If the same approach is adopted for the new units, this could mean that it would take 12 auction cycles for the SA-NSW and NSW-SA interconnector residues to be fully allocated. For example, if the first auction for these units took place in Q3 2026 (for Q4 2026), only 6% of the residues would be allocated in the first quarter of PEC's operation (Q4 2026), and Q3 2029 would be the first quarter with 100% auctioned units. This would expose ElectraNet and Transgrid to uncertain positive IRSR exposures over these three years, potentially leading to large swings in transmission prices to consumers.

It would also leave significant positive residues undistributed to the market.

AEMO and the SRC should therefore consider the optimal timetable to auction these new units and any flexibility that should be maintained. Information could be published to the market through the reporting requirements set out below.

4.3 AEMO will be required to update relevant procedures and publish information on loop arrangements, including return of sold units

4.3.1 AEMO will provide regular updates to industry before the loop commencement date

The final rule requires AEMO to publish information relevant to the loop transition as soon as practicable, and keep this information up to date. [246] This is critical to keep the market informed about the commencement of the loop.

> As soon as practicable after the commencement date, AEMO must publish information about:
>
> (1) the timing and process for the integration of the transfer capacity of the PEC interconnector in dispatch and settlements; and
>
> (2) rights and obligations of eligible persons with respect to SRD units affected by the matters in (1).

AEMO has advised that its reporting will include progress updates on the following implementation activities and consultation/changes to the relevant supporting documents/processes:

- Representation of PEC in dispatch systems

245 Refer to appendix C.2.2 of the draft determination and AEMO's Guide to the Settlements Residue Auction for further details on the auction process for SRD units.

246 Clause 11.188.3(c) and (d) of the Final Rule.

- NRM process
- Implementation of new IRSR allocation methodology in settlement systems
- Inclusion of PEC as a directional interconnector in SRA rules
- Release of SRD units for PEC
- Arrangements for return and re-auction of sold units for SA-VIC and NSW-VIC impacted by the introduction of PEC and changes to IRSR calculations introduced by the final rule
- Published inter-network test program.

AEMO canvassed this information in its PEC Market Integration Paper,[247]and its Draft High Level Impact Assessment document,[248] which also include indicative implementation timeframes. It has advised that the timing and details discussed in these documents will be updated after the release of this final rule.

4.3.2 AEMO will have a streamlined process to update the auction rules, constraint formulation guidelines and IRSR methodology

To implement the final rule, AEMO will need to update its procedures and relevant auction material.

At a minimum, AEMO will need to:

- review and amend the auction rules
- review and amend the network constraint formulation guidelines, which would cover a new clamping procedure[249]
- review and amend the spot market operations timetable.

Transitional clauses 11.188.2 and 11.188.3 require AEMO to review, and update where necessary, the auction rules, the timetable and constraint formulation guidelines. To assist AEMO to make these changes in advance of Q3 2026, the final rule allows AEMO to use the expedited rules consultation procedure (as opposed to the standard rules consultation procedure).[250] This recognises that AEMO has relatively limited time to implement the required changes.

AEMO may also need to make changes to its existing IRSR allocation methodology.[251] However, the final rule includes a savings provision that deems the methodology in place on the commencement date to meet the requirements of the final rule.[252]

4.3.3 These arrangements respond to stakeholder requests for clarity on loop commencement and arrangements for affected units

ENA and Transgrid noted the many layers of uncertainty relating to the commencement and operation of the loop.[253] This included uncertainty of SRA outcomes, unit termination and re-auctioning, and when SRD units for SA-NSW and NSW-SA would first be auctioned. They noted these uncertainties create forecasting challenges for CNSPs, which impacts transmission price

247 Refer to https://www.aemo.com.au/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper.

248 Available here: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/project-energyconnect-market-integration-project.

249 These activities were also necessary under the draft rule, although the draft rule did not specify each requirement.

250 Clause 11.188.2(c)(1) and 11.188.3(b) of the Final Rule. There is no consultation requirement for AEMO's allocation methodology, consistent with the existing NER requirements.

251 The Final Rule adopts the calculations used by AEMO's existing IRSR methodology so it is unlikely to need substantial amendments. However, minor changes may be necessary, for example, to fix references to the NER. This methodology is not currently prescribed by the NER and so the final rule elevates the requirement for the methodology to the NER (clause 3.6.5(b) of the Final Rule).

252 Clause 11.188.3(e) of the Final Rule.

253 Submissions to the directions paper: ENA, p.4; Transgrid, pp.4-6.

setting to be completed by March 2026 for the 2026-27 financial year. Forecasting errors could lead to cash flow risks for CNSPs, alongside bill volatility and increased costs to consumers.

Transgrid proposed a number of measures to manage this issue.[254] This included setting timing requirements for unit termination decisions and re-auctioning of units, starting auctions for NSW-SA and SA-NSW units in 2025, creating a temporary AEMO facility, and waiving of interest adjustments for incorrect forecasts.[255]

We agree that CNSPs face cash flow risks due to the requisite data being unavailable at the time they need to publish FY26-27 transmission prices in March 2026. We consider this will likely be a challenge for a few years until PEC auction outcomes stabilise. It will likely be more acute early on, and then ease over time.

While we understand these concerns, most of these solutions cannot be addressed by the final rule:

- setting timing requirements for unit termination decisions and re-auctioning of units - this relates to the contractual rights of unit holders, and the Commission considers that the arrangements for affected SRD units should be dealt with outside of the Rules (see section 4.3.4)
- starting auctions for NSW-SA and SA-NSW units in 2025 - there is not sufficient time available for AEMO to commence the auctions for new units this year, but the final rule addresses this to the extent possible in the requirements introduced for auction and reporting arrangements described above (see section 4.2 and section 4.3.2).
- AEMO holding fund - this has the issues discussed in section 2.4.6.
- waiving the interest adjustment under clause 6A.23.3(f)(3) NER - it is not clear what the magnitude of this issue will be, but given there is always some revenue uncertainty resulting in unders and overs, transmission businesses generally have some flexibility to deal with this revenue uncertainty. To the extent this is a broader problem, the Commission considers it would need to be considered more holistically. In addition, such changes may also be inconsistent with the requirements of the National Electricity Law (NEL).[256]

Nonetheless, we consider that the clarifications on loop commencement described in section 4.1, the auction requirement described in section 4.2 and the reporting arrangements described in section 4.3 will assist with CNSPs forecasting concerns.

4.3.4 We consider it is important that participants have rights to terminate previously sold units

The final rule applies netting off calculations to previously sold SRD units for the NSW-VIC and VIC-SA interconnectors (from the ‘loop settlements start date’). This was also the proposal in the directions paper.[257]

SRD units are sold up to three years in advance of the quarter in which they pay out. This means that some SRD units have already been sold for the VIC-NSW/NSW-VIC and SA-VIC/VIC-SA directional interconnectors of the loop that will be formed by PEC. Netting off calculations will apply to the positive IRSR attributed to these already sold units, so this will impact the payouts to these SRD unit holders.

254 Transgrid, submission to the directions paper, pp.5-6.

255 Refer to clause 6A.23.3(f)(3) of the NER.

256 Part 3, Division 1B of the NEL sets out the requirements of the rate of return instrument.

257 Refer to section 3.4.2 of the directions paper, p.35.

The Commission considers it important that affected SRD unit holders have appropriate termination rights, as raised by the AEC and Stanwell in response to the directions paper.[258] Material published by AEMO as part of the PEC implementation project also indicated that AEMO supported allowing termination of affected SRD units in the event of netting.[259]

We note that the EUAA considered that terminated units should not be re-auctioned because this would allow unit holders to buy them back at a lower price, reducing the proceeds to consumers.[260] We acknowledge the EUAA's view, however, we consider that the ability to terminate and re-auction units has benefits because:

- It promotes more stable cash flows for consumers, as IRSR associated with these units would otherwise be considered 'unsold IRSR' and passed to CNSPs.
- It provides auction participants the opportunity to bid for re-auctioned units at what they consider is fair value for the netted SRD units (rather than holding previously sold units that do not reflect this value). We note that a price adjustment between termination and re-auctioning may reflect a 'fair market value' for these units.[261]

Re-auctioning also allows the maxiumum amount of IRSR possible to be distributed to the market to assist with inter-regional hedging (subject to any timing considerations that may limit the ability to re-auction).

Stakeholders emphasised the need for clarity in the rights to terminate units, and any relevant processes or timeframes:[262]

- ENA specifically supported applying netting off calculations to previously sold units, but requested consideration of a time limit for when already sold units would need to be terminated by, and whether they would be re-offered at future auctions. This would assist with forecasting cash flows due to unsold IRSR passed on to CNSPs.
- Stanwell requested clear, timely communication of how previously-sold units would be treated under the new rules, including processes and timeframes for cancellation.
- AEMO considered that there is uncertainty in how the rule would apply for termination rights under the existing auction participation agreement:[263]

  > Clause 16.5 of the Auction Participation Agreement (APA) currently allows an auction participant to terminate a distribution agreement if a change in the calculation of settlements residue for the relevant units is published after the date of the relevant auction. A final rule (in the present draft form) is likely to be a change that this provision was intended to cover. However, given the updated methodology will not be applied before the physical completion and commissioning of PEC-2, the date from which SRA units are affected is inherently uncertain.

To address this, AEMO suggested that the final rule could:

- clarify which SRD units would be allowed to be terminated

258 Submissions to the directions paper: AEC, p.4; Stanwell, p.3.

259 Refer to Section 7.2 of https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/pec-market-integration-paper/directions-paper-for-consultation/pec-market-integration—-directions-paper-for-consultation.pdf?rev=97dc92956cfa44f0a5e4b0623 54cea72&sc_lang=en

260 EUAA, submission to the directions paper, p.3.

261 The use of netted units as part of a market participant's overall hedging strategy is discussed in section 2.4.3.

262 Submissions to the directions paper: ENA, pp.4-5; Stanwell, p.3; AEMO, pp.4-5.

263 AEMO, submission to the directions paper, p.4.

- require AEMO to clarify the process for unit termination (including a potential cut-off date) and re-auctioning.[264]

As stated above, the Commission supports appropriate rights to terminate affected SRD units. The Commission considers this may include, if appropriate, allowing termination in circumstances not covered by the terms of an existing APA.

However, the Commission considers that the arrangements for affected SRD units should be dealt with outside of the Rules. This is primarily because termination rights are a contractual matter between AEMO and SRA participants. The Commission also considers it is likely to be beneficial for AEMO to have flexibility in managing these arrangements, once it has had an opportunity to consult with the SRC and holders of affected units.

Accordingly, the Commission has not made rules specifying the arrangements for termination and re-auctioning of affected SRA units as part of this final rule. The Commission considers that AEMO should consider the potential for participants ‘gaming’ transitional arrangements (as raised by the EUAA) and the potential timing impacts on CNSPs (as raised by ENA) in making decisions on termination and re-auctioning of units.

The Commission also agrees that it is important to provide clarity on the transitional arrangements for holders of affected SRD units. The final rule includes requirements for AEMO to provide information about these matters under the reporting arrangements discussed in section 4.3.1.

264 AEMO, submission to the directions paper, pp.4-5.

5 Future review

Box 7: Key points

- We maintain our view that there is merit in reviewing how IRSR is allocated through the SRA to determine whether the arrangements meet the needs of both the current and future NEM.
- The NEM Expert Panel Review Draft Report recently made a draft recommendation that the AEMC should review interconnector hedging arrangements, because stronger inter-regional hedging is likely to be needed to support investment in variable renewable energy. We support the recommendation to conduct a future review and consider that it would be valuable to investigate how best to set up the interconnector hedging arrangements for success in the NEM given the changing generation mix.
- Through this rule change process we identified potential issues with IRSR arrangements, the SRA and SRD units that we consider merit further attention.
- A review would provide the opportunity to consider holistically the IRSR and SRA arrangements across both radial and looped interconnectors, and consider any changes that would promote liquidity, make SRD units a more effective inter-regional hedging instrument, and so promote the interests of consumers.
- Given our concern that the SRA framework is not working as effectively as it could, across both radial interconnectors and transmission loops, a future review could consider:
  - The overall value to consumers of the SRA arrangements
  - The allocation methods for the cash flows associated with IRSR - positive and negative, SRA proceeds, and unsold IRSR.
  - Auction arrangements for SRD units – including whether auctions should occur beyond three years ahead (this would deliver on the recommendation by the NEM Expert Panel in its Draft Report).
  - The operation and governance of the SRC.
  - Cost recovery arrangements for SRA proceeds and any unsold IRSR.
- We currently intend to conduct a review after at least a year of market operation. This will allow us to consider operational data following the introduction of PEC and conduct quantitative analysis, but will maintain flexibility on timing based on how market outcomes evolve.

In this chapter:

- Section 5.1 outlines our reasoning for recommending a future review
- Section 5.2 outlines the scope of the review
- Section 5.3 outlines our detailed analysis that has informed our view on the scope of the review.

5.1 We consider there is merit in a future review of IRSR and SRA arrangements

Consistent with our draft determination and directions paper, the findings of the NEM Expert Panel, and the majority of stakeholder feedback, we intend to review IRSR and SRA arrangements in a future review. Such a review would ideally benefit from at least one year of PEC operational data to conduct analysis, as well as the completion of the NEM Expert Panel review process. At the same time, we consider that it is important to maintain discretion on timing to respond as market outcomes evolve, so we have not included a requirement for this review in the final rule.

5.1.1 This rule change has highlighted broader issues with IRSR and SRA arrangements in the NEM

The final rule puts in place new arrangements for IRSR in transmission loops. These are needed prior to the introduction of the loop to provide certainty to the market, CNSPs and AEMO, and to ensure the benefits of the loop to consumers can be realised as soon as possible.

However, stakeholder views and our own analysis throughout this rule change process have highlighted that there may be broader issues with how IRSR is allocated through the SRA, such that the arrangements are not best meeting the needs of consumers in both the current and future NEM.

These issues include:

- SRD units do not provide any hedge for consumers or market participants when IRSR is net negative, both on radial interconnectors and transmission loops.
- SRD units are generally sold ‘at a loss’ for consumers.
- Current cost recovery arrangements expose CNSPs to cash flow risk.

In addition, market participants who use SRD units to hedge inter-regional price risk have reiterated that SRD units are not ‘firm’ – that is, the payouts they receive from SRD units do not match the underlying cash flow volatility they face when they trade across regions. This reduces the value they place on these as a hedging instrument, and discourages inter-regional trade.

Based on stakeholder feedback and further analysis, elaborated in section 5.1.2 below, we consider these issues are worth investigating through a future review.

5.1.2 Stakeholders generally supported a review

In response to our directions paper, TNSPs, consumer groups and AEMO generally supported a future review of SRA arrangements with a broad scope. Market participants provided more mixed feedback, but some were also broadly supportive. For example:[265]

- ECA supported a future review scope that considered the broader impacts of IRSR arrangements for consumers.
- Delta and Origin supported a comprehensive review including alternative (non-netting) options, with Origin noting that the review should be scoped ‘transparently’ - including a clear problem statement, modelling, and engagement.
- Alinta Energy suggested that the review should wait until after the AEMC had better addressed the concerns raised in its submission (that is, better analysed the alternative options for this rule change proposal other than netting) and the outcomes of the NEM Review had been finalised.
- Other market participants (Snowy Hydro, EnergyAustralia, AGL and the AEC), suggested that the AEMC should wait for at least one year of PEC operation and completion of the NEM Expert Panel review before considering an AEMC review, and that there was not necessarily a clear need for a review.

265 Submissions to the directions paper: ENA, p.2; Delta, p.2; Origin, pp.2, 10; Alinta Energy, p.7; Snowy Hydro, p.3; EnergyAustralia, p.2; AGL, pp.3-4; AEC, p.4; ENA, p.6.

- The ENA supported a more timely initial review, which could consider both the inter- and intra-regional settlement arrangements, followed by a second review which could consider the operational data from PEC.

The NEM Expert Panel Review Draft Report recommended that the AEMC explores options to promote longer-term contracting across regions

The NEM Expert Panel Draft Report highlights that:[266]

> Interconnectors are critical to delivering the full benefits of the NEM, particularly as more weather-dependent generation connects. Their importance will continue to grow as interconnectors link regions with diverse weather patterns.

It recommends:

> 9D: The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.

We agree with the Draft Report's characterisation of the importance of interconnection in a future NEM and support the recommendation for a future AEMC review.[267] Our review could explore options to promote longer-term contracting across regions in conjunction with reforms to existing interconnector hedging arrangements. We explore our preliminary analysis on auction timing in further detail in section 5.3.2 below.

5.2 A review would consider whether IRSR and SRA arrangements across the NEM are operating in the best interests of consumers

It is not within the scope of this rule change to propose a new policy position for negative IRSR on radial interconnectors, and we could not observe operational data from PEC in making this final rule (as discussed in chapter 1).

As such, the scope of the future review would include the arrangements for the SRA and for SRD units for both existing 'radially' connected regions and future looped regions. That is, the review would not just cover the arrangements between SA, NSW and Victoria, but also Tasmania-Victoria, and NSW-Queensland.

The items below set out some focus areas that could be explored in a future review:

- Whether the sale of SRD units represents good value for consumers, and whether and how value might be improved (see section 5.3.1)
- Whether the IRSR arrangements and SRD units are designed in a manner that best enables market participants to manage inter-regional price risk, and for consumers and CNSPs to best manage IRSR risk. This could include:
  - the allocation of negative IRSR - and whether there is a case to make all negative IRSR available for hedging through SRD units
  - the allocation method for SRA proceeds and unsold IRSR (see section 3.3)

266 Nelson, et.al., National Electricity Market wholesale market settings review, Draft Report, August 2025, p.195.

267 The AEMC's submission to the NEM Expert Panel Review Draft Report is published on our website: AEMC, Submission to national electricity market settings review draft report, 17 September 2025, available at: www.aemc.gov.au/market-reviews-advice/future-wholesale-market. We discuss specific items relating to the SRA and IRSR arrangements on p.30 of our submission.

- Whether the current arrangements, timings and quantities for selling SRD units supports effective inter-regional hedging and outcomes that are in the best interests of consumers. These considerations could include:
  - options to extend the forward period for selling inter-regional settlement residue units beyond three years - for example to 10 years as proposed by the NEM Expert Panel Review
  - options to allocate SRD units across tranches more dynamically
  - whether a reserve price should be introduced.
- Broader implementation considerations such as the functionality of the software platform through which the SRA is conducted.
- The operation and governance of the SRC. We consider it would be timely to look at whether the operation and governance is fit-for-purpose given:
  - the SRC has significant discretion over the availability of units, the scope and timing of auctions, and reporting of auction outcomes (NER 3.18.5(b)) and these decisions can have significant impacts on auction outcomes, with consequences for market participants and CNSPs, and ultimately consumers.
  - there is limited transparency about the SRC's decision-making criteria and processes.
- The efficiency of the current arrangements for managing IRSR cash flows, including:
  - whether there is a way that amounts owed to consumers could move through to consumers more quickly, and
  - whether the role for CNSPs in managing cash flows is designed in the best interests of consumers.

Stakeholder feedback provided in response to the questions raised by the NEM Expert Panel Draft Report may also be relevant for such a review's scope.[268]

We would conduct this review with a clear terms of reference, with consultation as per our usual process. Through the review, we would capture the views and analysis provided by industry, electricity networks and consumer representatives. This would respond to Origin's request (noted above) for a comprehensive review process with transparent scoping.[269]

5.3 Detailed analysis on historical auction outcomes has helped inform our views on the scope and timing of a future review

The following sections provide further analysis and response to stakeholders on the broader issues we have identified through the course of this review. The future review would provide an opportunity to consider these issues holistically and consult comprehensively with stakeholders.

5.3.1 We could examine whether the SRA is delivering adequate benefits for consumers

A future review could seek to understand whether the full benefits of auctioning SRD units in the SRA are being realised for consumers.

SRD units have important benefits in promoting competition through facilitating increased inter-regional trade, providing more efficient investment signals, and managing the risks of serving customers across regions. However, the Commission considers it is worth investigating whether the benefits of the SRA may be being eroded, because the revenue consumers are receiving through SRA proceeds has proven to be much lower than the average value of the IRSR allocated

268 Nelson, et.al., National Electricity Market wholesale market settings review, Draft Report, August 2025.

269 Origin, submission to the directions paper, p.10.

to SRD unit holders over time. We would work closely with stakeholders in considering this question.

As previously outlined in our draft determination,[270] consumers have received an average of $0.72 in SRA proceeds for every $1 paid to SRD unit holders over the 20 years from Q2 2004 to Q2 2025. See Figure 5.1 below.

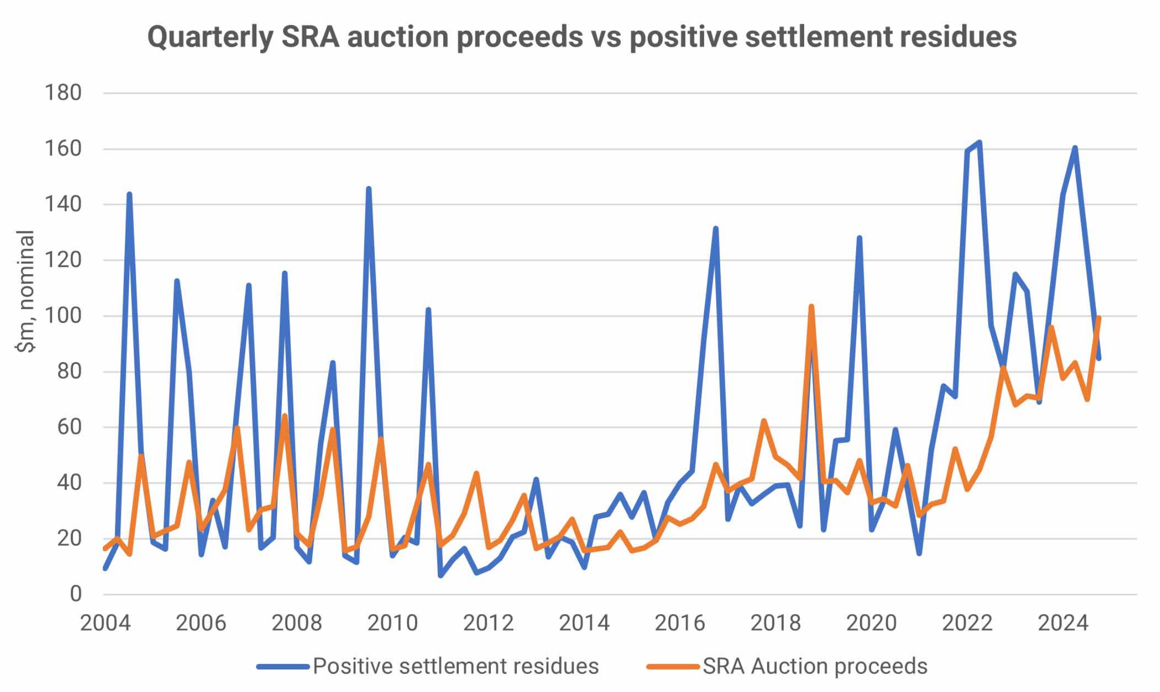
We consider that this result is worth considering further in a future review, given:

- The argument that proceeds should be higher than IRSR is based on SRD units providing valuable risk management benefits in reducing volatility for market participants who trade inter-regionally, as outlined above. To the extent that SRD units effectively address inter-regional price separation, the value of the unit should theoretically be greater than the expected positive IRSR, as the volatility of the units payouts works to offset other downside risks in their portfolios and therefore should improve risk-adjusted returns. Consequently, we would expect such market participants, if they are risk averse, to be willing to pay more than the expected return of the instrument to reduce their overall level of risk. All else equal, we might expect the return to consumers from selling SRD units would be positive, not negative.
- On the other hand, SRD units are not firm, reducing a portion of the value to the purchasers of these units, as outlined above. As a consequence, a small pool of parties may be willing to purchase SRA units, particularly given the inherent variability of IRSR. This increases the risk that the auctions are not sufficiently competitive. At an extreme, analysis of these factors could conclude that consumers could be better off overall if SRD units were not sold, or were only sold above a certain reserve price.

Our quantitative analysis, along with the factors that could theoretically be at work to both raise and lower SRA proceeds, all support considering the question of whether current SRA and IRSR arrangements are maximising the value of units for consumers. SRA arrangements can have a range of benefits to consumers, including facilitating inter-regional trade and greater competition, and providing a more predictable cash flow to consumers than IRSR, which promote lower and more stable prices for consumers. It is therefore beneficial to maximise the value of competition and these benefits for consumers through well-designed SRD units and auction processes. We intend to investigate these outcomes, their causes, and possible remedies through the proposed review in a consultative manner.

270 Refer to section 4.3 in the draft determination, pp.41-42.

Figure 5.1: SRA proceeds are persistently lower than actual positive residues



Source: AER data, Quarterly settlement residues and settlement residue auction proceeds, December 2024; AEMO, Auction Report 2025, Quarter 1, April 2025, p.21.

Some stakeholders questioned our analysis

In submissions to our draft determination and directions paper, stakeholders provided some critique, and requested further analysis. The AEC suggests that the expected returns on SRD units are reasonable, when considering the risks borne by the holder of the unit, and that consumers receive "fair value".[271]

In particular, the AEC noted that average returns of SRD units have averaged between 22-31% (depending on the calculation method), and that this return was reasonable given the volatility of returns as *a stand-alone product*.[272]

Our view, articulated in the directions paper,[273] is that SRD units should be functioning as a risk management product, and that the analysis of their value should include the value they provide to unit holders in reducing total expected volatility, rather than being analysed as a stand-alone or income-generating product. We consider it would be worthwhile exploring these views further in a future review, including the role of imperfect foresight in considering the value of SRD units.

Origin recommended the AEMC provide a more transparent and granular presentation of the data comparing SRA proceeds to SRD unit payouts, and particularly how SRA outcomes have changed over time. Origin referred to analysis conducted by the Energy Reform Implementation Group in 2007, and also provided its own analysis, indicating that SRA proceeds per dollar of positive

271 Refer to AEC, submission to the draft determination, pp.2-4; and AEC, submission to the directions paper, pp.2-3.

272 AEC; submission to the draft determination, p.3.

273 Refer to section 6.2 of the directions paper, p.51.

residues had been lower before 2010, when a previous form of netting ceased to apply in the NEM.[274] The Commission notes that the NEM - including the generation mix, demand characteristics, retail competition, hedging, and bidding practices - have evolved significantly in the last 15 years. At the time of the Energy Reform Implementation Group analysis, the NEM regions were different and included the Snowy region.[275] The netting approach in the final rule is also different to the netting that was previously applied in the NEM, as it is specific to transmission loops and nets IRSR arising on arms of the loop in the same trading interval. The returns of netted SRD units for the transmission loop can only be confirmed when operational data is available.

That said, we expect that investigating the returns of netted and un-netted SRD units in a future review would be worthwhile, along with a more detailed analysis of the historical data. We agree that our analysis to date has been high level, preliminary and insufficient to form firm conclusions. A full analysis of the data should be a focus of a future review and should be used to examine issues across the NEM that were beyond the scope of this rule change request. The value of SRD units should be considered in conjunction with wholesale and contract market outcomes. A full analysis would also analyse the “firmness” of units which is a data-intensive process.

5.3.2 We could examine SRA arrangements and timings

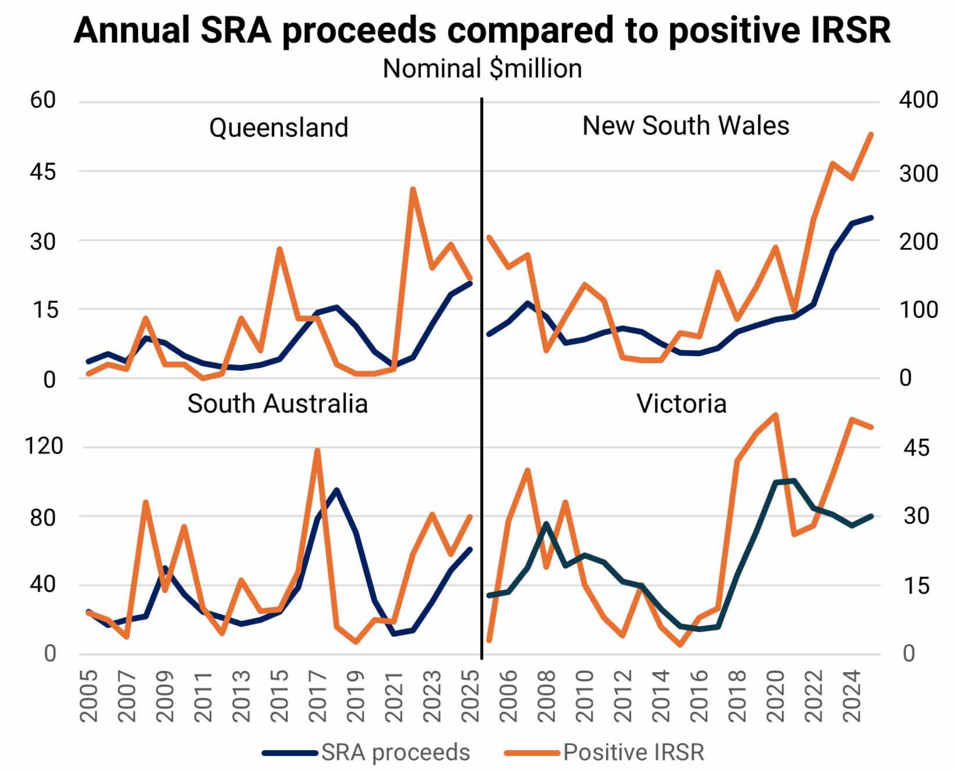
We consider that a future review should consider how tranches of SRD units are auctioned over time. Our analysis suggests that earlier auction periods tend to achieve lower prices than later ones, perhaps reflecting increased uncertainty, and that auction results appear to lag recent trends in actual IRSR. This suggests there is a case to change or extend the period for auctioning units, and consider whether the supply of units in each auction period should be more dynamic depending on the demand for units through auction periods over time.

Figure 5.2 suggests that SRA proceeds ‘lag’ positive IRSR. Given the rolling three year auction window, this would imply that SRA outcomes are heavily influenced by current trends in positive IRSR. The implication is that auction outcomes may not contain much information about future expectations for inter-regional prices (and flows).

274 Origin, submission to the directions paper, pp.8-9.
Refer to Energy Reform Implementation Group, Energy Reform, p.232, https://www.energy.gov.au/sites/default/files/energy-reform-way-forward-aust-final-report-exec-summary-2007_0.pdf.
Refer to appendix D of the consultation paper, pp.41-45, for a history of IRSR arrangements in the NEM. No netting has been applied since the National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts Rule) 2009 No 17, which commenced in 2010.

275 The Snowy region was abolished following a rule change completed in 2007. See National Electricity Amendment (Abolition of Snowy Region) Rule 2007 No. 7.

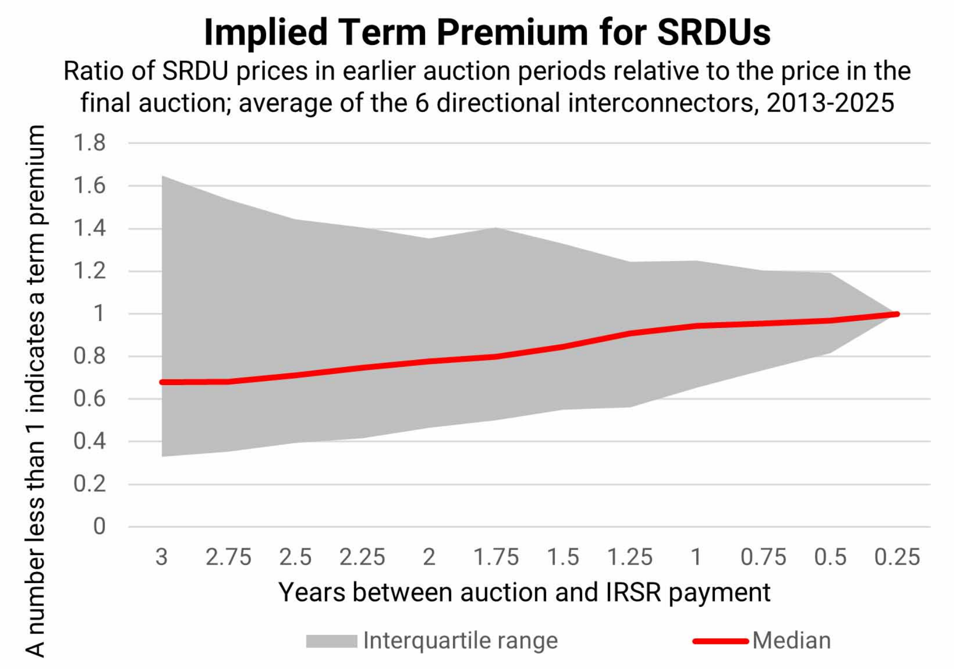
Figure 5.2: SRA proceeds have also been lower than positive residues for individual regions in the NEM



Source: AER data, Annual Settlement Residues (https://www.aer.gov.au/industry/registers/charts/annual-settlement-residues), accessed August 2025; AEMO MMS data.

We also analysed auction outcomes for the 12 quarterly auction tranches over the current three-year window for auctioning capacity, by calculating the ratio of SRD unit prices in all tranches to the price in the final auction period. Given that payments for all tranches are due, and earn revenues, concurrently, this ratio can be thought of an implied (or proxy) 'term premium' for buying a unit further in advance of the settlement period: if the ratio is less than one in the earlier auction tranches, it would suggest a term premium. Figure 5.3 presents the average of the results across the directional interconnectors.

Figure 5.3: SRD unit outcomes across auction tranches



Source: AEMO MMS data.

The analysis shows that there is a 'term premium', with units auctioned two or three years in advance tending to sell at a lower price than units closer to the contract period, on average. This likely reflects that there is additional uncertainty over what expected positive IRSR will be for purchasers of these earlier units. Consistent with the increased uncertainty for earlier units, the auction clearing prices for earlier units tend to be extremely variable, with a much larger range of price outcomes for earlier tranches.

As shown in appendix C, similar patterns hold for individual directional interconnectors, although the magnitudes vary considerably for each interconnector.

Relatedly, the NEM Expert Panel Draft Report has recently sought feedback on whether a 10-year period for auctioning SRD units would provide forward-looking information to the market. Options to promote longer-term contracting across regions should be explored in conjunction with reforms to existing interconnector hedging arrangements.

5.3.3 We could consider whether creating hedging arrangements for negative IRSR could benefit consumers, TNSPs and SRD unit holders

We consider that a future review should examine the benefits of establishing hedging arrangements for negative IRSR.

In our draft determination, we highlighted the potential benefits that could be provided by instruments which explicitly hedge the risk that IRSR is negative. In this final determination, SRD units allocate IRSR to unit holders in a transmission loop when loop IRSR is net positive. However, IRSR is recovered from consumers on an unhedged basis - through an increase to transmission prices - when IRSR in a transmission loop is net negative, and when IRSR on a radial interconnector is negative. Furthermore, in cases where there is net positive IRSR, but the initial allocation to an arm is negative, the payout to that SRD unit associated with that arm is zero, and the negative IRSR is instead offset from the remaining arm that has positive IRSR.

Across both radial interconnectors and transmission loops, SRD units only provide a method to hedge price separation which results in financial losses for the market participants - where the price in the exporting region where electricity in generated is higher than the price in the importing region where it is consumed. However, there is no hedging instrument for price separation that results in profits to market participants and costs to consumers. In principle, creating a hedging instrument for cases where the price that generation earns is above the price in the importing region could also provide benefits to consumers, CNSPs and market participants, as:

- consumers face a clear risk – the risk of being allocated an uncertain amount of negative IRSR. It would reduce their risk if they could pay a fixed upfront fee to avoid an uncertain amount of negative IRSR.
- conversely, when there is negative price separation, participants who trade inter-regionally earn higher returns, because the price they are paid (or need to pay) for generation is above the cost incurred to supply their customer base. Even though negative IRSR corresponds to an increase in profit, because this additional return is still uncertain and unpredictable, they may wish to earn a more stable return. Therefore, a market participant may be willing to be paid an upfront fee to receive negative IRSR, which would offset the movements in wholesale prices when there is negative price separation, and potentially provide a more stable overall return.
- CNSPs would also benefit from a reduction in cash flow volatility if hedging arrangements for negative IRSR were introduced.

This suggests that the arrangements for inter-regional price risk management – the fundamental intent of SRD units – may be improved by creating consistent arrangements for SRD units which include all IRSR (positive and negative). The review could consider approaches such as:

- introducing a new set of negative SRD units (which pay out only the net negative IRSR) alongside the existing positive SRD units (which pay out net positive IRSR), for radial interconnectors and transmission loops.
- alternatively, both the positive and negative IRSR arising on a directional interconnector over a period could be pooled, making negative IRSR available for hedging and obviating the need for secondary netting on transmission loops.

Any consideration of creating hedging products for negative IRSR would need to carefully consider prudential arrangements, given that such products could result in liabilities for unit holders.

Finally, we note that hedging arrangements for negative IRSR (like those for positive IRSR) could provide benefits in addressing cash flow risks for CNSPs - reducing the volatility and improving their ability to forecast the cash flows they receive from IRSR.

Stakeholders provided limited feedback to this analysis in response to our draft determination or directions paper. As discussed in section 2.4.6, the AEC and Origin briefly raised the possibility of allocating negative IRSR via creating a negative hedging SRD unit.[276]

5.3.4 We could consider the role of CNSPs

We consider that a future review should consider if CNSPs are the most appropriate party to pass on costs and revenues to consumers.

276 Submissions to the directions paper: AEC, p.4; Origin, p.9.

Auction proceeds, unsold IRSR, and (net) negative IRSR accrue to CNSPs, who pass these onto consumers annually through reductions or increases to transmission prices.[277] Differences between the forecast and actual revenues and costs from these arrangements are reflected in a NPV-neutral 'true-up' through the following year's transmission prices.[278]

CNSPs can incur a range of costs forecasting and managing cash flows from IRSR, depending on the scale and predictability of these cash flows.

As noted by stakeholders in their submissions,[279] this raises the question of whether CNSPs should be allocated these revenues and costs, or whether the cash flows should instead be allocated to another party at a lower net cost for consumers. This could be considered holistically in the future review.

The unpredictability of these revenues and costs exposes CNSPs to cash flow volatility stemming from wholesale and SRA market outcomes. If this uncertainty is small, it is manageable and may not be particularly distortionary to the extent it is offset by swings in other revenues and costs. But if they become harder to forecast as the NEM becomes more interconnected and weather dependent, the unexpected costs may be harder to absorb if actual outcomes are lower-than-expected, and unexpected revenues may be more problematic for CNSPs to earn a regulated rate of return on if the outcomes are higher-than-expected.

277 Clause 6A.23.3(b)(1) and (e) of the NER.

278 Clause 6A.23.3(f) of the NER.

279 See, for example, submissions to the directions paper: ENA, pp.3-4; Delta, pp.1-2; AFMA, pp.6-7.

A Rule making process

A standard rule change request includes the following stages:

- a proponent submits a rule change request
- the Commission initiates the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
- stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

The Commission has used a longer-than-standard process for this rule change due to the complexity of the issues involved.[280]

Between publishing the draft determination and this final determination, we held a technical working group, released a directions paper and indicative rules drafting and engaged directly with stakeholders, including inviting written feedback and conducting bilateral meetings. These were additional steps to provide stakeholders with the opportunity to engage with the complex issues raised in feedback to the draft determination and a revised direction for the rule change request. These additional steps are elaborated in appendix A.3 below.

You can find more information on the rule change process on our website.[281]

In this appendix:

- Appendix A.1 outlines the changes proposed by AEMO in its rule change request
- Appendix A.2 outlines the reasons AEMO proposed these changes
- Appendix A.3 outlines the process that the AEMC has taken in coming to this final rule decision, including details of the additional steps we used to engage with stakeholders.

A.1 AEMO proposed changes to the allocation of negative IRSR in transmission loops

AEMO's rule change request proposed that negative IRSR in a transmission loop should be reallocated amongst the interconnectors in the loop when the net residue for the loop is positive.

Appendix C of the AEMC's draft determination[282] provides more information about IRSR, the current arrangements for the allocation of positive and negative IRSR, transmissions loops, the spring washer effect, and clamping.

The rule proposed by AEMO would have operated as follows:[283]

1. When net residue for the loop is positive, any negative IRSR on individual arms of the loop would be reallocated to the other arms in proportion to the positive IRSR they have accrued in the same dispatch interval, and assigned to the importing CNSPs for those arms.

280 Notices under section 107 of the NEL extending the time for making the draft and final rule were published on 8 August 2024 and 20 March 2025.

281 See our website for more information on the rule change process: https://www.aemc.gov.au/our-work/changing-energy-rules

282 Refer to Appendix C of the draft determination, p.50.

283 Refer to AEMO's rule change request, pp.14-17.

2. When net residue for the loop is negative, negative IRSR accruing on any individual arm would be allocated directly to the importing CNSP as per the current rules.
3. In both cases, positive IRSR would be distributed to SRD unit holders, with the proceeds of SRAs being assigned to the respective importing CNSPs, as per the current arrangements. Note that any negative IRSR reallocated to an arm accruing positive IRSR according to point 1 would not be deducted from that positive IRSR, which is allocated to SRD unit holders.
4. There would be no change to SRAs, except for the introduction of SRD units relating to PEC, which would not require a rule change.[284]
5. The interconnectors forming the loop would only be subject to clamping when the net residue for the loop is negative.[285] This change to clamping would be implemented by an AEMO procedure change, rather than a rule change. See section 3.1.3 and appendix C.4 of the draft determination for more detail.[286]

AEMO's rule change request was developed following its PEC Market Integration body of work carried out between 2022 and early 2024.[287] This process included two rounds of stakeholder consultation, including with retailers, gentailers, TNSPs and industry peak bodies. For a summary of the stakeholder feedback that AEMO received, see appendix A of our consultation paper.[288]

A.2 The proposed allocation method sought to better align costs with beneficiaries

AEMO considers that the current approach to allocating negative IRSR would cause a misalignment of costs and beneficiaries if applied to transmission loops.

In a transmission loop, negative IRSR can accrue on one or two arms as part of efficient dispatch while the overall net IRSR for the loop is positive. AEMO considers that in these circumstances, the cost of negative IRSR on some arms of the loop supports positive IRSR on other arms of the loop, and overall efficient dispatch.[289] Modelling commissioned by AEMO suggests that this outcome - where negative IRSR accrues on some arms while net IRSR is positive - is likely to arise frequently.[290]

Under the current rules, all negative IRSR would be allocated to the importing region(s) in the relevant dispatch interval. AEMO considers that this allocation approach would result in an unfair distribution of IRSR (and, therefore wealth) if applied to transmission loops because it would assign all costs to the importing region(s), which does not reflect the benefits of the loop flow:[291]

> the current process of assigning costs [i.e. negative IRSR] to importing TNSPs is not equivalent to assigning costs to beneficiaries of inter-regional power flow. Current process may therefore result in (unfair) significant wealth transfer between consumers in the different NEM regions.

To remedy this, AEMO proposed that the costs of the negative IRSR should be distributed proportionately between consumers in those regions that received the auction proceeds for the

284 Ibid., pp.10-11.

285 Ibid., pp.10-11.

286 Refer to p.15 and p.56 of the draft determination respectively.

287 AEMO, PEC Market Integration Papers.

288 Refer to appendix A of the IRSR arrangements for transmission loops consultation paper, p.37.

289 Ibid., p.9.

290 ACIL Allen, 'Modelling the settlement effects of PEC'.

291 Refer to AEMO's rule change request, p. 9.

positive IRSR arising in that dispatch interval. AEMO's proposed rule sought to achieve this by reallocating negative IRSR in a dispatch interval to the arms of the loop accruing positive IRSR in that same dispatch interval (in proportion to the positive IRSR accrued), provided that the net IRSR for the loop is positive.[292]

For cases where the net IRSR for the loop is negative, AEMO proposed that the current arrangements should continue to apply for transmission loops. That is, negative IRSR would be allocated directly to the importing region.[293]

In addressing why the proposed rule treats net positive and net negative cases differently, AEMO noted that:[294]

> Where negative IRSR is accruing on a single directional interconnector, but settlement is in aggregate surplus around the parallel transmission configuration, that negative IRSR is supporting the accrual and value of the positive IRSR into the other importing regions.

Section 2.2.2 of our consultation paper discusses the significance of net residue outcomes and explains why net positive residue is consistent with an efficient dispatch solution.[295]

The rule change request did not propose any changes to how positive IRSR is allocated, and did not raise any wealth reallocation issues with respect to positive IRSR.

A.3 The process we have followed in making this rule

The steps we have followed in making this rule are outlined below:

1. On 8 August 2024, the Commission published a notice advising of the initiation of the rule making process and consultation in respect of the rule change request.[296] The Commission also published a consultation paper identifying specific issues for consultation. The Commission also extended the timeframe for the draft and final determinations due to the complexity of the issues in the rule change request. This extended the publication of the final determination to 27 March 2025.[297]
    a. On 5 September 2024, submissions to the consultation paper closed. The Commission received 12 submissions as part of this first round of consultation. The Commission considered all issues raised by stakeholders in submissions.
2. On 12 December 2024, the Commission published a draft rule determination and draft rule. Issues raised in submissions to the consultation paper were summarised and responded to in the draft rule determination.
    a. On 30 January 2025, submissions to the draft determination closed. The Commission received 14 submissions as part of this second round of consultation. The Commission considered all issues raised by stakeholders in submissions.
    b. On 20 March 2025, the Commission extended the timeframe for the final determination due to the complexity of the issues raised in submissions to the draft determination.[298] This extended the publication of the final determination to 25 September 2025 (the date of this final determination).

292 AEMO, PEC Market Integration final report, pp.41-42.
293 Refer to AEMO's rule change request, p.15.
294 Ibid., p. 9.
295 Refer to section 2.2.2 of the consultation paper, pp.17-18.
296 This notice was published under section 95 of the NEL.
297 This notice was published under section 107 of the NEL.
298 This notice was published under section 107 of the NEL.

   c. On 15 April 2025, the Commission held a technical working group session and invited written feedback from working group members on a revised policy direction and options for the rule change request. Membership was made up of representatives from market participants, market bodies and networks. The materials from this session were published on the AEMC's website here, and we invited stakeholder feedback on the material.
3. On 19 June 2025, the Commission published a directions paper, accompanied by indicative rules drafting, that proposed a revised direction for the rule change request. Issues raised in submissions to the draft determination were summarised and responded to in the directions paper. The Commission also took into consideration the feedback received through the technical working group and written feedback in developing the directions paper.
   a. On 10 July 2025, submissions to the directions paper closed. The Commission received 17 submissions as part of this third round of formal consultation. The Commission considered all issues raised by stakeholders in submissions.
   b. The Commission held targeted engagement sessions with industry bodies, and other market participants on request, prior to the close of submissions to the directions paper and considered further information and feedback provided through meetings and in writing after submissions to the directions paper closed.

Throughout the entire rule change process, the Commission also held ongoing bilateral meetings with AEMO. In particular, between the draft determination and final determination, we sought advice and feedback in writing on technical considerations relevant to the netting off approach and how it would be implemented, as well as various other implementation aspects relating to how AEMO will accommodate the loop in its systems and processes.

Issues raised in submissions to the directions paper are discussed in detail and responded to throughout this final rule determination and in appendix F.

B Examples to illustrate net trade

This appendix includes a series of worked examples which support our reasoning for using the net trade approach, outlined in section 3.2, for the final rule. The examples are intended to:

- explain how the net trade approach functions, in comparison to the existing arrangements and the netting approach proposed in the directions paper, and
- highlight the benefits of the net trade approach relative to these other approaches.

Table B.1 explains the purpose of each example.

Table B.1: List of examples

Example	Description	Key point of example
1	Radially connected regions (Figure B.1)	Highlights that changes in interconnector flows because of PEC make the existing IRSR allocation process problematic, even when there is no negative IRSR allocated to any individual arm under the status quo allocation.
2	Looped regions, with positive IRSR on each arm under status quo allocation (Figure B.2 and Figure B.3)	
3	Looped regions, with negative IRSR on one arm under status quo allocation (Figure B.4 and Figure B.5)	Highlights that the net trade approach is fit for purpose regardless of the IRSR allocation under the status quo arrangements.
4	Looped regions, with negative IRSR on one arm after first step of net trade allocation (Figure B.6)	Illustrates how net trade works when there is negative IRSR allocated to one of the arms after the first step of the net trade approach.
5	Looped regions, with net negative IRSR (Figure B.7)	Illustrates how net trade works with net negative IRSR.
6	Looped regions, with losses (Figure B.8 and Figure B.9)	Illustrates how net trade works with losses.

Across the examples:

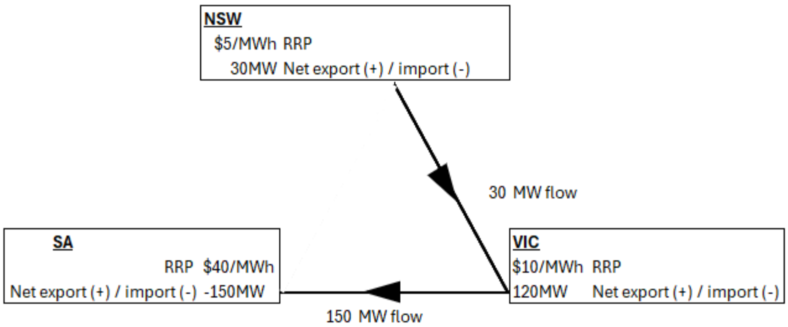
- the **quantity** of generation and load in each region is unchanged (except for slight differences in example 6).
- the **flows** along each of the loop interconnectors in examples 2 to 5 are unchanged. Flows differ in example 1 as this example shows the network before PEC is introduced - and therefore before loop commencement. Flows in examples 1 - 5 are lossless, for simplicity. Flows differ slightly in example 6 due to the inclusion of losses.
- **regional prices** differ, which in turn drives different total quantities of IRSR, and different allocations of IRSR under the different methodologies.
- there is no **intra-regional congestion**, for simplicity.

With respect to this final point, this means that in each of the examples the resulting SRD units are ‘firm’. In practice, intra-regional congestion can result in ‘unfirm’ SRD units. This is a problem that arises under *any* of the approaches (the current allocation process, proportional netting, or net trade).

B.1 Example 1

This example, shown in Figure B.1, outlines the current allocation process when applied to radially connected regions (i.e., pre-PEC). In the example, the current allocation process results in positive IRSR on each arm. This example demonstrates the flows that arise on radially connected regions, and will be compared in subsequent examples to the flows arising for looped regions.

Figure B.1: Example 1: radially connected regions



	Status quo	
	SRDU payout	Flow
VIC-SA	$4500/h	150MW
SA-VIC	-	-
NSW-SA	-	-
SA-NSW	-	-
NSW-VIC	$150/h	30MW
VIC-NSW	-	-
TNSP	-	
Total	**$4650/h**	

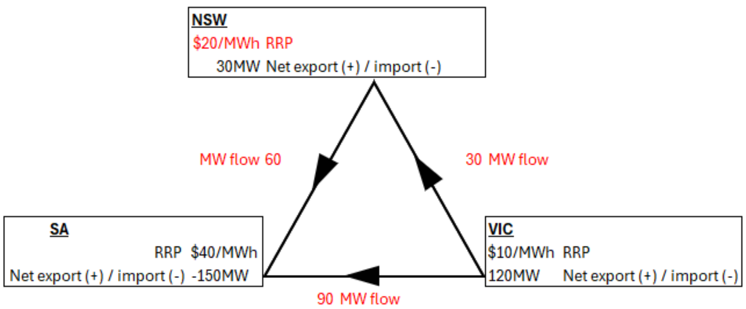
Note: In this and following examples, we have used a trading interval of one hour to simplify the calculations. 'SRDU payout' refers to the total of SRD unit payouts for a one-hour trading interval.

B.2 Example 2

In this example, PEC is operational. Generation and load quantities remain the same. Critically, the *flows* along the interconnectors substantially change compared to example 1. Consistent with Kirchhoff's circuit laws, two thirds of the generation from Victoria takes the short route to the load in SA directly, while one third takes the long route via NSW. Similarly, two thirds of the generation from NSW takes the short route directly to SA, while one third takes the long route via Victoria, partially offsetting the flows from Victoria to SA via NSW.[299] Prices are also different compared to example 1 owing to the spring washer effect.

The physical flows and allocation of IRSR under the status quo approach are shown in Figure B.2. Changes compared to example 1 are highlighted in red.

Figure B.2: Example 2: looped regions, status quo allocation of IRSR resulting in positive IRSR allocated to each arm



	Status quo / proportional netting	
	SRDU payout	Flow
VIC-SA	$2700/h	90MW
SA-VIC	-	-
NSW-SA	$1200/h	60MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	$300/h	30MW
TNSP	-	
Total	**$4200/h**	

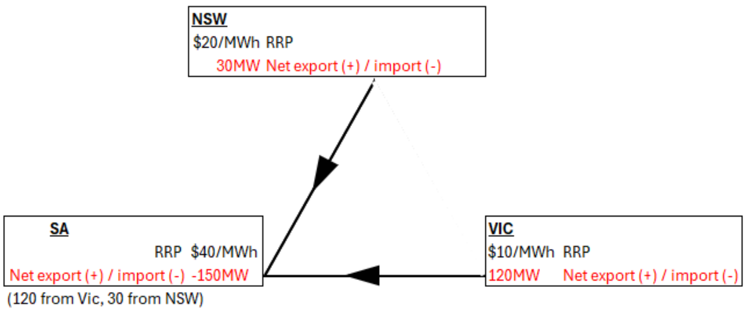
299 The one-third and two-thirds figures are illustrative. The actual proportions will differ, depending on the relative electrical impedance of each of the routes.

The IRSR along each of the arms under the status quo arrangements is positive. The netting approach proposed in the directions paper, which we refer to as 'proportional netting', only altered the allocation of IRSR between arms compared to the status quo when one or more of the arms was allocated negative IRSR under the status quo approach. Consequently, in this example the allocation under the status quo and proportional netting is identical.

Importantly, under either the status quo approach or proportional netting (which are the same in this case), the allocation does not appear ideal from the perspective of market participants seeking to hedge their inter-regional price exposure. Unlike under the radial example, where the Victorian generators could simply purchase 120MW of VIC-SA SRD units to hedge their risk, there are no longer that many VIC-SA SRD units available. To hedge their risk they instead would have to purchase SRD units on *all three arms*: all 90MW of VIC-SA, all 30MW of VIC-NSW and 30MW of NSW-SA, effectively synthesising 120MW of VIC-SA SRD units. Hedging strategies will therefore be substantially altered with the introduction of PEC, *even if there is no negative IRSR on any individual arm under the status quo allocation.* The problem, therefore, is not negative IRSR per se, but rather the existing allocation process when applied to a loop.

Under the net trade approach, the allocation of IRSR shifts away from focusing on flows on interconnectors and the routes that the electricity takes. Instead, the focus is on the generation and load quantities themselves: the net exports and net imports between the regions. In Figure B.3, the 'flows' are not physical, but rather the net trades between the regions (changes emphasised in red). What matters is the net trades (in red), not the flows along the lines (which are not stated in the diagram).

Figure B.3: Example 2: looped regions, net trade allocation



	Net trade	
	SRDU payout	Net trade quantity
VIC-SA	$3600/h	120MW
SA-VIC	-	-
NSW-SA	$600/h	30MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	-	-
TNSP	-	
Total	**$4200/h**	

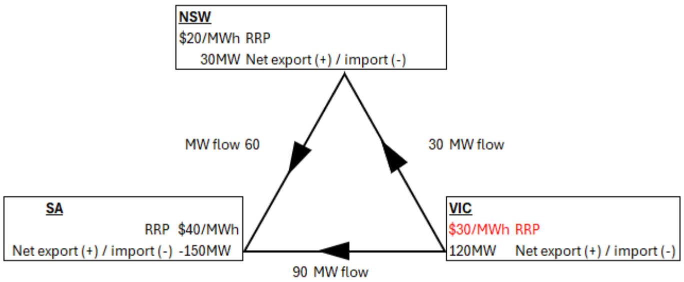
Note: The net trade quantities in this table are equal to the net exports from Victoria and NSW respectively, which represent the net transfers of electricity to SA. This is consistent with the definition of 'net trade quantity' in the Final Rule (clause 3.6.6(a) and (f)-(h)). The SRDU payout is calculated in this simplified example by multiplying the net trade quantity by the price difference between the regions ('net trade amount' in the Final Rule, clause 3.6.6(i)-(j)).

Note that the total IRSR is the same as under the status quo allocation approach. Further note that the allocation is directly what market participants collectively require to hedge their risk: 120MW of VIC-SA SRD units and 30MW of NSW-SA SRD units. Unlike under the status quo and proportional netting approaches, there is no need to 'synthesise' any SRD units from those made available via the SRA. This is instead done automatically as part of the net trade allocation.

B.3 Example 3

The setup of this example (Figure B.4) is identical to example 2, other than the Victorian price is the middle price, rather than the lowest price, of the three regions (highlighted in red).

Figure B.4: Example 3: negative IRSR allocated to an arm under status quo approach



	Status quo		Proportional netting	
	SRDU payout	Flow	SRDU payout	Equivalent flow
VIC-SA	$900/h	90MW	$771/h	77.1MW
SA-VIC	-	-	-	-
NSW-SA	$1200/h	60MW	$1029/h	51.4MW
SA-NSW	-	-	-	-
NSW-VIC	-	-	-	-
VIC-NSW	-	-	-	-
TNSP	-$300/h		-	
Total	**$1800/h**		**$1800/h**	

This results in negative IRSR arising on the VIC-NSW arm under the status quo approach, and so, under that approach, the negative IRSR is being allocated to the CNSP for the importing region (NSW).[300] As discussed in the directions paper, and section 2.4.6 of this paper, we are concerned that this could place significant costs and risks on consumers. We are also concerned that market participants are collectively 'over-hedged', in that the amount they are paid for generation and all the SRD unit payouts is higher than what they have to pay for load. We expect that, as risk-averse entities, market participants would instead prefer to pay less into the SRA, swapping a variable positive cash flow ($300/h in this case) for a reduction in payments to acquire the SRD units.

Under the proportional netting approach, the negative IRSR is instead allocated to the other two positive arms, in proportion to the positive IRSR allocated to those arms under the status quo approach. *Collectively*, the total IRSR is exactly what the market requires to hedge its inter-regional price risk. However, the problem with this approach is that the resulting 'quantities' of individual SRD units (~73MW for VIC-SA and ~51MW for NSW-SA) are largely disconnected from the hedging requirements of the generators and loads. In the directions paper we noted that in principle it is possible for market participants to trade contracts to meet their individual hedging requirements.[301] We also acknowledged that this was not costless, particularly given the complicated re-allocation of negative IRSR based on the proportion of positive IRSR on the remaining arms. Stakeholder feedback, noted in section 3.1.2, highlighted these difficulties.[302]

The net trade approach addresses this concern. By focusing on the net generation and load in each region (net exports and net imports) rather than on the physical interconnector flows, it directly allocates IRSR between the arms in a way that meets the hedging requirements of market participants. That is, the net trade approach directly allocated 120MW to the VIC-SA arm and 30 to the NSW-VIC arm, which is exactly what market participants collectively require to hedge inter-regional price risk.

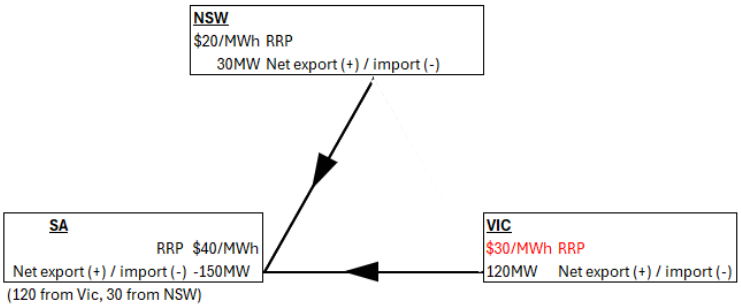
This is illustrated in Figure B.5 below. The allocation method and quantities allocated to each arm are identical as under example 2 (although the total IRSR is different, due to the different Victorian price). As above, in the net trade method, what matters is the net trades, not the flows along the lines (which are not stated in the diagram).

300 ($20/MWh - $30/MWh) x 30MW = -$300/h.

301 Refer to appendix A of the directions paper, pp.56-57.

302 Submissions to the directions paper: Origin, pp.3-6; AFMA, pp.3-5, EnergyAustralia, p.3; AEC, pp.1-2.

Figure B.5: Example 3: net trade allocation



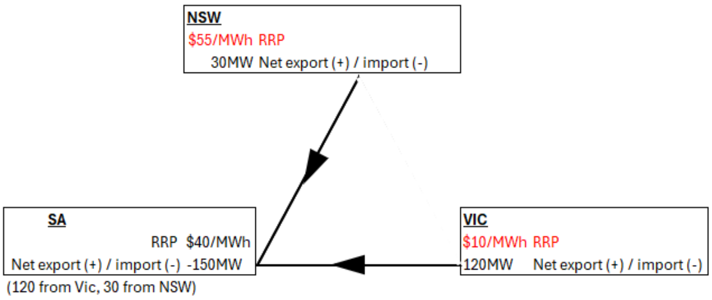
	Net trade	
	SRDU payout	Net trade quantity
VIC-SA	$1200/h	120MW
SA-VIC	-	-
NSW-SA	$600/h	30MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	-	-
TNSP	-	
Total	**$1800/h**	

Note that the total IRSR ($1,800/h) is the same in example 3 regardless of the allocation method (status quo, netting or net trade).

B.4 Example 4

The setup of this example (Figure B.6) is identical to examples 2 and 3, other than the Victorian price is the lowest price and the NSW price is the highest price (highlighted in red). Note again that the diagram represents the net trades (which are stated in the diagram), and not the physical flows (which are not stated in the diagram).

Figure B.6: Example 4: net trade with secondary netting



	Net trade	
	SRDU payout	Net trade quantity
VIC-SA	$3150/h	120MW
SA-VIC	-	-
NSW-SA	-	30MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	-	-
TNSP	-	
Total	**$3150/h**	

Under the net trade approach, the result (after the first step) is negative IRSR being allocated to one of the arms (NSW-SA). The provisional net trade amount assigned to NSW-SA would be ($40/MWh - $55/MWh) x 30MW = -$450/h. In this case, a secondary netting step allocates this negative amount to the remaining positive arm, which in this example is VIC-SA, as shown in Table B.2.[303] In effect, the remaining arm is allocated all the net positive IRSR.

303 Provided that the total IRSR is positive - if not, see example 5.

Table B.2: Breakdown of secondary netting

	First step	Secondary netting	Total (first step + secondary netting)
VIC-SA	120 x (RRPSA - RRPVIC) = 3,600	+ 30 x (RRPSA - RRPNSW) = -450	120 x (RRPSA - RRPVIC) + 30 x (RRPSA - RRPNSW) = 3,150
NSW-SA	30 x (RRPSA - RRPNSW) = -450	- 30 x (RRPSA - RRPNSW) = +450	0
Total	**3,150**	**0**	**3,150**

As discussed in section 3.2.1, this approach has various benefits because it:

- allocates all the net positive IRSR to SRD unit holders and so avoids allocating negative IRSR to CNSPs and the associated risks and costs for consumers, and
- avoids the possibility of negatively paying SRD units, and the resulting auction design and prudential implications.

As with proportional netting, this results in an allocation of SRD units which is not directly consistent with the collective needs of the market. The market still needs 120MW of VIC-SA and 30MW of NSW-SA SRD units to manage its risk, but the available payout on VIC-SA is equivalent to only 105MW,[304] and there is no payout available on NSW-SA. In contrast to proportional netting, however, it appears easier for market participants to enter further trades under the net trade approach. The complexity of these further trades appears much reduced compared to the directions paper approach. While the appropriate trades and contract structures are for market participants to determine, we note that a seemingly appropriate contract structure would be to simply 'back out' the secondary netting step. That is, those purchasing the VIC-SA SRD units could 'sell' the equivalent of negatively paying NSW-SA SRD units (i.e., bilateral contracts which pay out on the difference between the NSW and SA prices), to 'natural' counterparties such as the exporters in NSW meeting load in SA, who would otherwise be exposed to inter-regional price risk. The terms of the contract could even be directly linked to the second step that AEMO takes (assisted by AEMO's reporting of the provisional net trade amount, see section 3.4.2). The VIC-SA SRD unit holder would make a fixed payment to its counterparty, and in return the counterparty would pay the VIC-SA SRD unit holder the negative amount of IRSR that was allocated to the VIC-SA SRD unit holders under the second step.

Of course, the bilateral trade involves the NSW-SA gentailer entering into a contract to reduce its exposure to a risk of *increased* profit (+$450/h, in this case). But it gets paid a fixed price in return for doing so. This is conceptually no different to a generator entering into a cap contract, where it foregoes the possibility of high profit arising from high spot prices in exchange for a fixed revenue stream.

This is illustrated in Table B.3, which shows that with these simple bilateral trades, each entity can perfectly hedge its risk. Relatively simple bilateral trades of this nature are not possible in the proportional netting approach preferred in the directions paper.

304 $3150/h / ($40/MWh - $10/MWh) = 105MW

Table B.3: Bilateral trading example

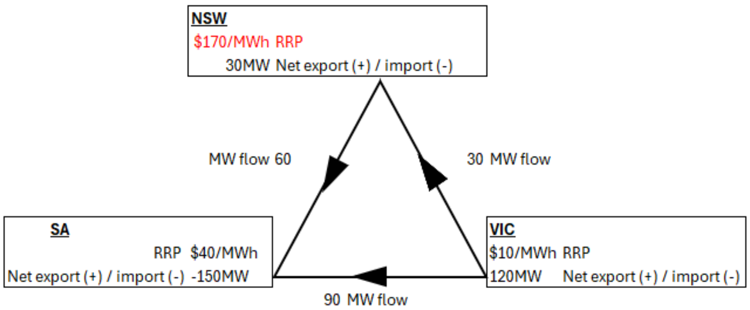
	Physical position	SRD unit payouts	Bilateral trades (see note)	Total
VIC-SA gentailer	120 x RRPVIC - 120 x RRPSA = -3,600	120 x (RRPSA - RRPVIC) + 30 x (RRPSA - RRPNSW) = +3,150	- 30 x (RRPSA - RRPNSW) = +450, less fixed payment made under bilateral trade	0, less fixed payment made under bilateral trade
NSW-SA gentailer	30 x RRPNSW - 30 x RRPSA = +450	0	+ 30 x (RRPSA - RRPNSW) = -450, plus fixed payment made under bilateral trade	0, plus fixed payment made under bilateral trade
Total	**-3150**	**+3150**	**0**	**0**

Note: In this example, we consider hypothetical bilateral trades which reverse the secondary netting step.

B.5 Example 5

Example 5, shown in Figure B.7, is identical to example 4, except that the NSW price (highlighted in red) rises sufficiently high that the total IRSR is negative.

Figure B.7: Example 5: net negative IRSR



	Netting off in a net negative case	
	SRDU payout	Net trade quantity
VIC-SA	-	-
SA-VIC	-	-
NSW-SA	-	-
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	-	-
TNSP	-$300/h	
Total	**-$300/h**	

This is a 'net negative' case. In this case, each SRD unit pays out zero, and all the negative IRSR is allocated to the CNSPs. This is the same as the approach we proposed for net negative cases in the directions paper. Our reasons for taking this approach in the final rule are discussed in section 3.2.2. The resulting risk to CNSPs and consumers is managed through clamping. The allocation of the net negative IRSR between the CNSPs is discussed in section 3.3.2.

B.6 Example 6

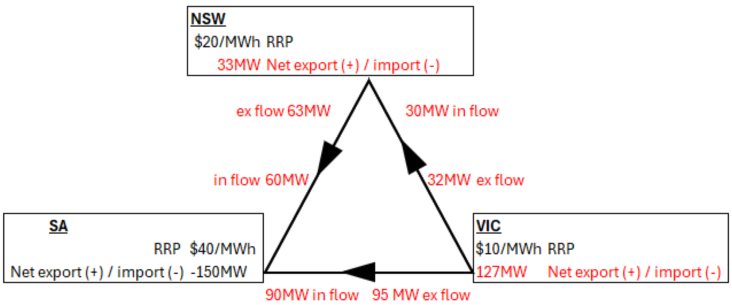
This example illustrates how net trade works given the loss of energy in transmission. This example supports the overview provided in section 3.2.3.

The prices in all three regions and net imports into SA are the same as in example 2. However, the net exports from Victoria and NSW (highlighted in red) are greater than in example 2, to account for losses:

- 32MW is exported from Victoria to NSW, but only 30MW arrives, with 2MW lost
- 95MW is exported from Victoria to SA, but only 90MW arrives, with 5MW lost
- 63MW is exported from NSW to SA, but only 60MW arrives, with 3MW lost.

The physical flows are illustrated in Figure B.8.

Figure B.8: Example 6: Losses



	Status quo / proportional netting	
	SRDU payout	Imported flow
VIC-SA	$2650/h	90MW
SA-VIC	-	-
NSW-SA	$1140/h	60MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	$280/h	30MW
TNSP	-	
Total	**$4070/h**	

The total IRSR around the loop is equal to $4,070/h, calculated as:

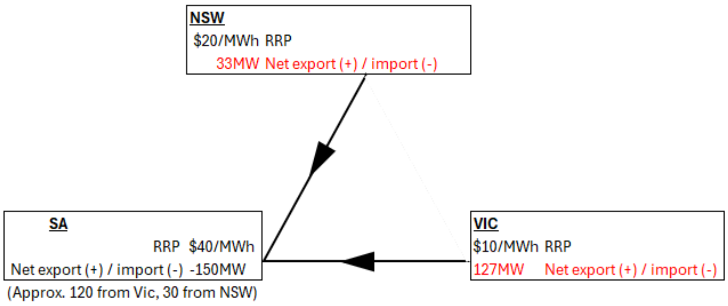
- what importing load is paying in SA: 150MW x $40/MWh = $6,000/MWh,
- less what exporting generators are being paid in NSW: 33MW x $20/MWh = $660/h,
- less what exporting generators are being paid in Victoria: 127MW x $10/MWh = $1,270/h.

The net export for each region (which will be used to determine net trade) is calculated as the exports on looped interconnectors less the imports on looped interconnectors (inclusive of losses):

- for Victoria, +95MW + 32MW = +127MW (net export)
- for NSW, +63MW - 30MW = +33MW (net export)
- for SA, -90MW - 60MW = -150MW (net import)

This is illustrated in Figure B.9.

Figure B.9: Example 6: Losses, net trade



	Net trade	
	SRDU payout	Net trade quantity
VIC-SA	**$3469/h**	127MW
SA-VIC	-	-
NSW-SA	**$601/h**	33MW
SA-NSW	-	-
NSW-VIC	-	-
VIC-NSW	-	-
TNSP	-	-
Total	**$4070/h**	

Since there are two exporting regions in this example, the net trade quantity on each of the VIC-SA and NSW-SA arms is equal to the net export from those regions. To determine the IRSR allocation to the arms, the net trade approach determines an initial allocation of funds to each arm based on the net trade quantities:

- for VIC-SA: 127MW x ($40/MWh - $10/MWh) = $3,810/h
- for NSW-SA: 33MW x ($40/MWh - $20/MWh) = $660/h

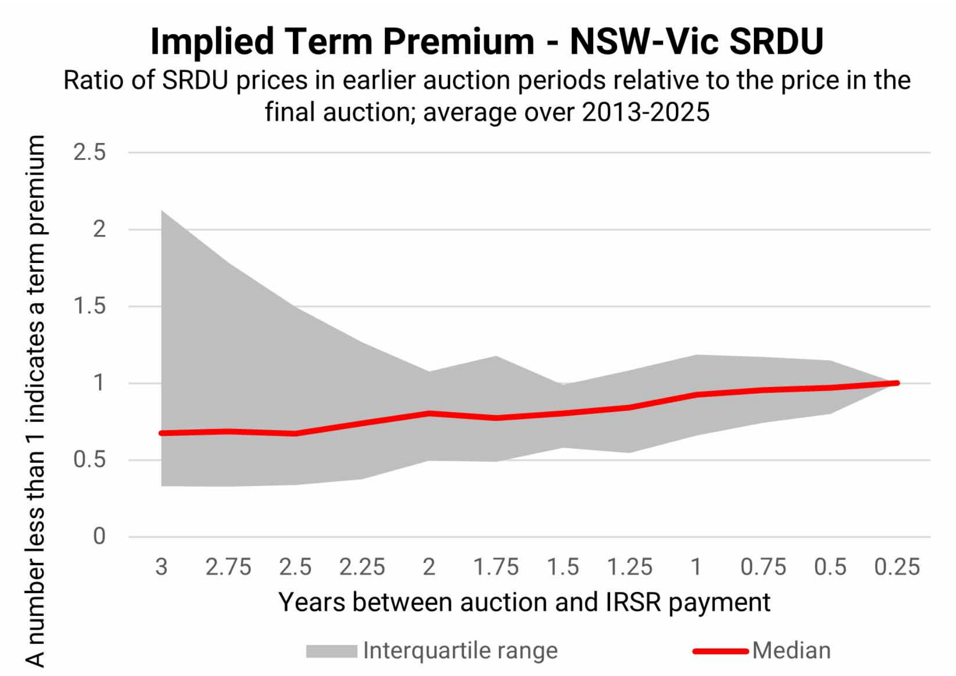
Because we have used the net *exporting* quantities, which are pre-losses, in these calculations, the dollars determined in this step ($4,470/h) exceed the actual IRSR of $4,070/h by $400/h. Each arm's allocation is then scaled down in proportion to its pre-loss allocation such that the total of the net trade amounts is equal to the net IRSR for the loop:

- for VIC-SA: $3,810/h / $4,470/h x $4,070/h = $3,469/h
- for NSW-SA: $660/h / $4,470/h x $4,070/h = $601/h
- giving a total of $4,070/h.

C Historic SRD unit price outcomes for individual auction tranches

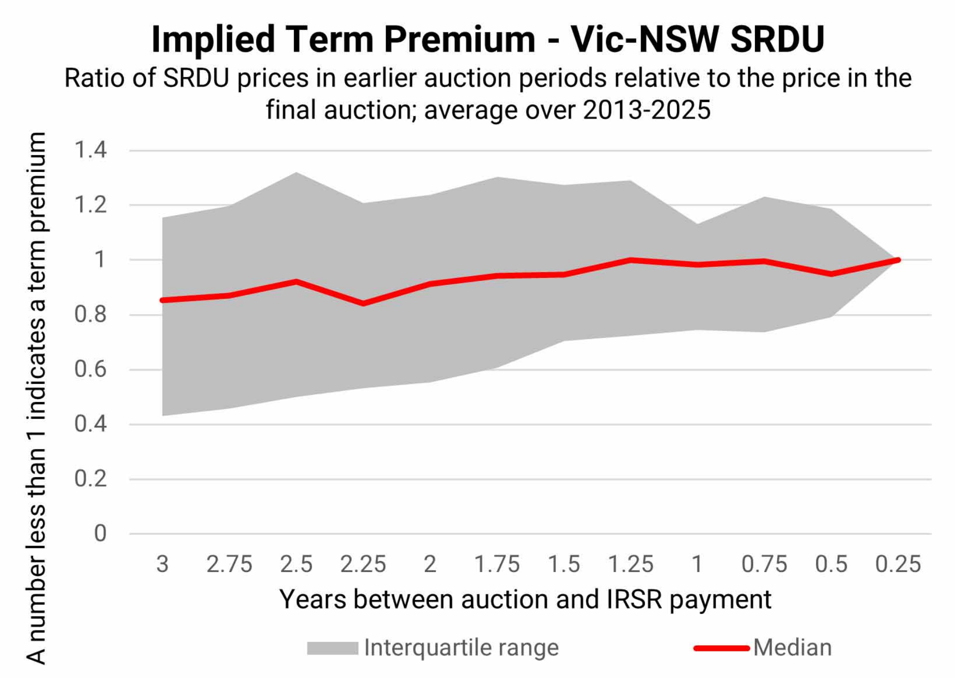
This appendix presents the results discussed in section 5.3.2 for each directional interconnector. It confirms there is an implied term premium for individual directional interconnectors, but that the magnitudes vary significantly across the interconnectors.

Figure C.1: NSW-VIC SRD unit outcomes across auction tranches



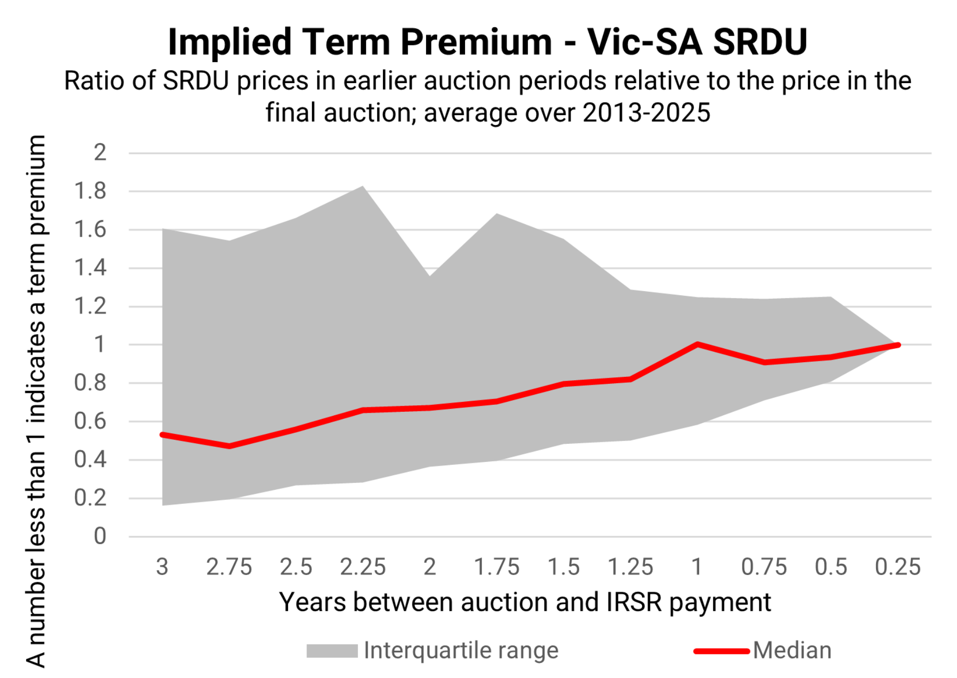
Source: AEMO MMS data.

Figure C.2: VIC-NSW SRD unit outcomes across auction tranches



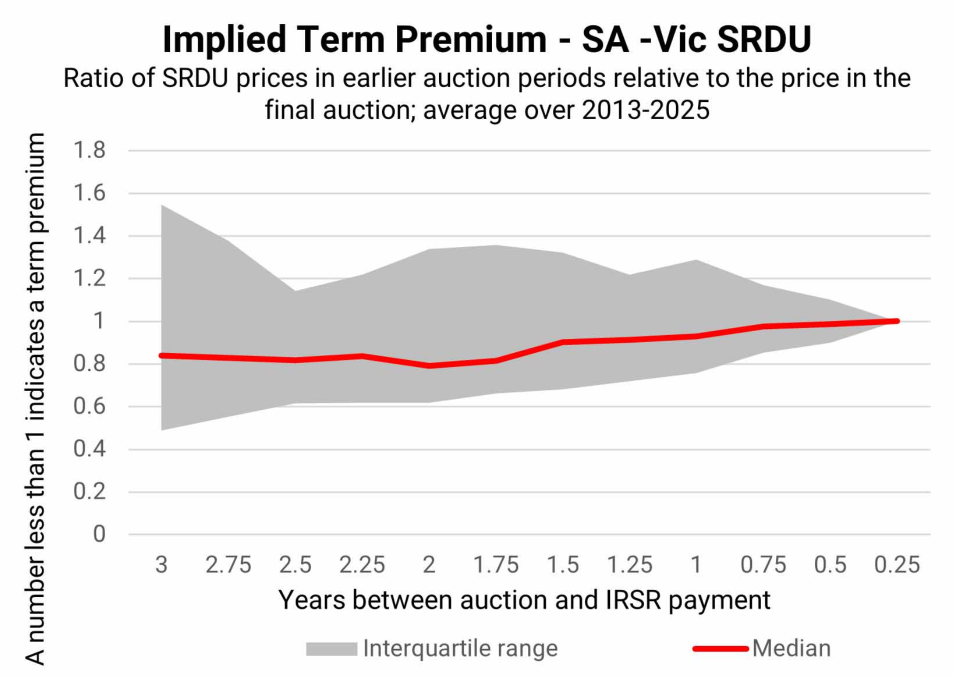
Source: AEMO MMS data.

Figure C.3: VIC-SA SRD unit outcomes across auction tranches



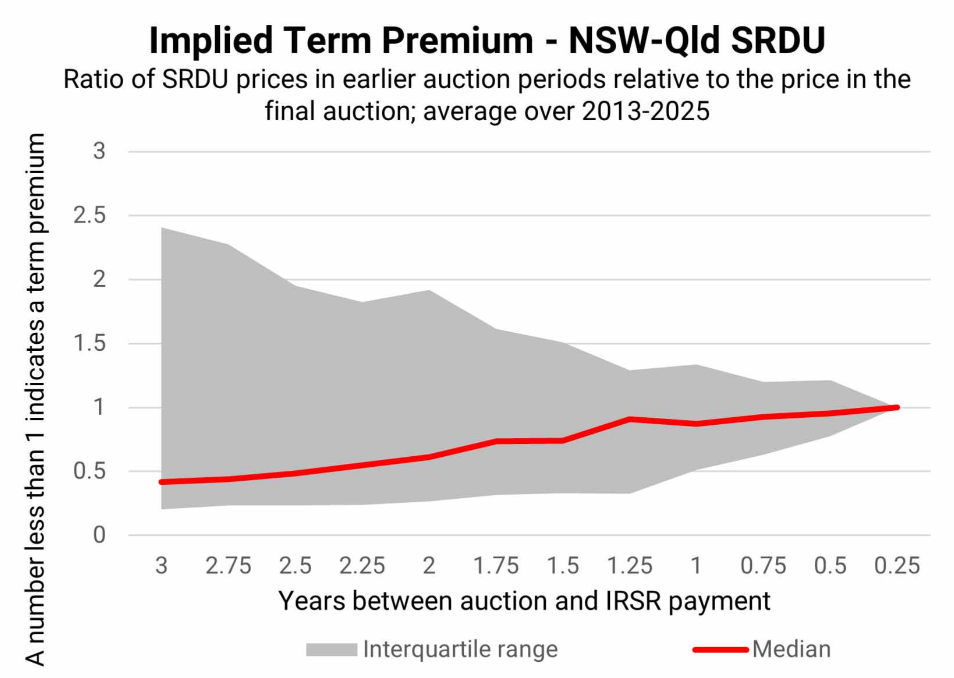
Source: AEMO MMS data.

Figure C.4: SA-VIC SRD unit outcomes across auction tranches



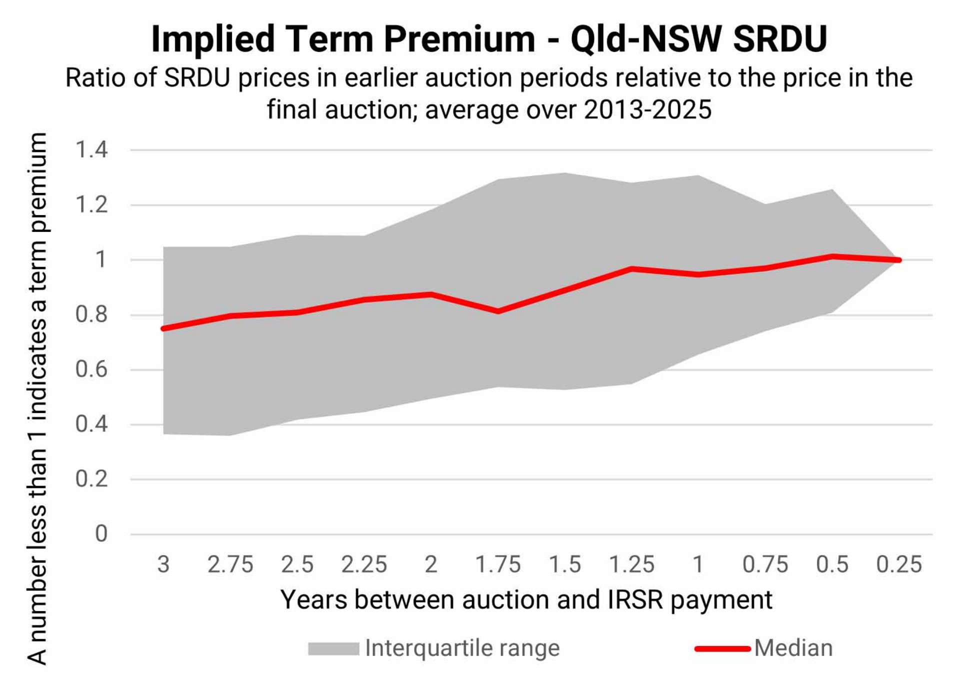
Source: AEMO MMS data.

Figure C.5: NSW-QLD SRD unit outcomes across auction tranches



Source: AEMO MMS data.

Figure C.6: QLD-NSW SRD unit outcomes across auction tranches



Source: AEMO MMS data.

D Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL for the Commission to make a final rule determination.

D.1 Final rule determination and final rule

In accordance with section 102 of the NEL, the Commission has made this final rule determination for a more preferable final rule in relation to the rule proposed by AEMO.

The Commission's reasons for making this final rule determination are set out in chapter 2.

A copy of the more preferable final rule is attached to and published with this final determination. Its key features are described in chapter 3 and chapter 4.

D.2 Power to make the rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules.

The more preferable final rule falls within section 34 of the NEL as it relates to the operation of the national electricity market (section 34(1)(a)(i)) and the activities of persons (including registered participants) participating in the national electricity market (section 34(1)(b)).

D.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the final rule
- the rule change request
- submissions received to the consultation paper, the draft determination, and the directions paper
- stakeholder input received at the technical working group held on 15 April 2025 and during other informal consultation
- the Commission's analysis as to the ways in which the final rule will or is likely to contribute to the achievement of the NEO
- the application of the final rule to the Northern Territory.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[305]

D.4 Making electricity rules in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[306] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

305 Under s. 33 of the NEL and s. 73 of the NGL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. In December 2013, it became known as the Council of Australian Government (COAG) Energy Council. In May 2020, the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting were established to replace the former COAG Energy Council.

306 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016

As the more preferable final rule relates to parts of the NER that apply in the Northern Territory, the Commission is required to assess Northern Territory application issues, described below.

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[307]

1. the national electricity system
2. one or more, or all, of the local electricity systems[308]
3. all of the electricity systems referred to above.

Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[309] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[310]

The Commission's determinations in relation to the meaning of the "national electricity system" and whether to make a uniform or differential rule are set out in chapter 2.

D.5 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to the Energy Ministers' Meeting that new or existing provisions of the NER be classified as civil penalty provisions or conduct provisions.

The more preferable final rule does not amend any clauses that are currently classified as civil penalty provisions or conduct provisions under the National Electricity (South Australia) Regulations.

The Commission does not propose to recommend to the Energy Ministers' Meeting that any of the amendments made by the more preferable final rule be classified as civil penalty provisions or conduct provisions.

307 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

308 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

309 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

310 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

E Summary of final rule

The current Rules deal with distribution of settlements residue in clause 3.6.5, the SRA in rule 3.18 and reporting of SRA results in clause 3.13.5A. Adjustments to transmission pricing for amounts recovered from, or paid to, CNSPs in connection with IRSR and the SRA are dealt with in clause 6A.23.3.

The final rule replaces clause 3.6.5 in its entirety for clarity and to update the approach and terminology.[311] Distribution and recovery of IRSR allocated to directional interconnectors, including the net trade methodology, are dealt with in new clause 3.6.6, with new reporting requirements added to clause 3.13.5A and transitional arrangements in clause 11.188. Table E.1 below explains the changes in more detail and the related or consequential amendments.

The final rule introduces several new concepts into the NER. These include the following terms in new clause 3.6.6:

- **parallel interconnector configuration** to refer to a transmission loop that connects three regions
- **looped region** to refer to each of the regions in the loop
- **looped interconnector** to refer to each of the directional interconnectors in the loop
- **allocation methodology** for the document that sets out AEMO's methodology for determining settlements residue for intra-regional and inter-regional amounts, and then assigning the IRSR to each directional interconnector[312]
- **allocation** to refer to the amount of IRSR (in $) that AEMO assigns to each directional interconnector in a trading interval, as calculated by AEMO using the allocation methodology
- **unsold settlements residue amount** to refer to any IRSR that remains after AEMO uses it for auction fees and distribution to SRD unit holders ('unsold IRSR' in the body of this determination).

Under the current NER, the term 'regulated interconnector' identifies the subset of interconnectors subject to the SRA and 'directional interconnector' refers to the aggregate flow over all the regulated interconnectors between two regions in a particular direction.[313] There are two directional interconnectors between each pair of adjacent regions and six directional interconnectors in a loop. Under the allocation methodology, the term 'notional interconnector' is used. This term has been incorporated in new clause 3.6.6 to support the net trade calculations and is explained in Table E.1.

Table E.1: Description of final rule

Clause	Description of final rule
3.6.5 overview	Current clause 3.6.5 is a set of principles to be applied by AEMO when apportioning settlements residue between inter-regional settlements residue (IRSR) and intra-regional settlements residue. The principles also explain how AEMO distributes or recovers these amounts. The current clause also contains principles allowing AEMO to determine the arrangements for recovering amounts relating to IRSR from CNSPs. AEMO has given effect to clause 3.6.5 through its

311 Refer to version 235 of the NER for the clauses prior to the making of the final rule.

312 AEMO, Methodology for the allocation and distribution of settlements residue.

313 Clause 3.18.1(c) of the NER.

Clause	Description of final rule
	allocation methodology and separate arrangements with CNSPs. The final rule replaces clause 3.6.5 in its entirety. The changes clarify the different categories into which settlements residue is assigned and move from a principles-based approach to a set of obligations for AEMO and CNSPs with respect to distribution and recovery of settlements residue. The final rule also includes reference to the allocation methodology used by AEMO for its detailed calculations.
3.6.5(a)	New clause 3.6.5(a) requires AEMO to determine, for each trading interval, the amount of settlements residue (which may be positive, negative or zero) assigned to each directional interconnector and the intra-regional settlements residue for each region. There is also an obligation in new clause 3.6.6(k) to publish the amount of settlements residue assigned to each directional interconnector - this is the 'allocation'. The need for these calculations is implicit in current clauses 3.6.5(a)(2) and (3) of the NER, but the final rule makes these explicit.
3.6.5(b) and 11.188.3(e)	New clause 3.6.5(b) requires AEMO to develop, publish and maintain the allocation methodology used for the determinations under paragraph (a). A transitional rule confirms that AEMO's current allocation methodology satisfies the requirements of this paragraph.
3.6.5(c) and (g)	These new clauses replace old clauses 3.6.5(a)(2) and (4). New clause 3.6.5(c) provides that the settlements residue assigned to directional interconnectors is paid or recovered in accordance with clause 3.6.6 and rule 3.18. New clause 3.6.5(g) confirms that this is subject to the requirement in clauses 5.7.7(aa)(3) and (ab) relating to recovery of negative settlements residue attributable to inter-regional testing.
3.6.5(d)	New clause 3.6.5(d) replaces old clause 3.6.5(a)(3) to the extent it provided for the distribution and recovery of intra-regional settlements residue. It maintains the principle that these amounts are recovered from, or distributed to, the CNSP for the relevant region.
3.6.5(e) and (f)	New clauses 3.6.5(e) and (f) replace old clause 3.6.5(a)(3) to the extent it provided for the distribution and recovery of settlements residue attributed to interconnectors that are not regulated interconnectors or providers of market network services. It maintains the principle that these amounts are distributed to, or recovered from, the CNSP for the importing region. Based on discussions with AEMO, the Commission understands that at present there are no interconnectors falling in this category.
3.6.5(h)	New clause 3.6.5(h) relocates old clause 3.6.5(c) subject to minor drafting changes. The clause deals with payment and recovery of settlements residue that accrues on designated network assets.
3.6.5(i) - (n)	New clauses 3.6.5(i) to (n) deal with payment of amounts relating to settlements residue that AEMO is required to recover from CNSPs. They replace current clauses 3.6.5(a)(4) and (4A) and paragraph (n) relocates old paragraph (b). Paragraph (i) requires AEMO to set off amounts owed to it by a CNSP on account

Clause	Description of final rule
	of settlements residue or auction proceeds against amounts that are owed to the CNSP by AEMO. Paragraph (j) requires AEMO to determine the time and method for payment by the CNSPs of amounts they owe with respect to settlements residue. Paragraph (l) requires CNSPs to pay in accordance with that determination and the following paragraphs deal with the mechanics of those payments, including providing for interest on late payments.
3.6.6 overview	New clause 3.6.6 explains how the settlements residue AEMO assigns to directional interconnectors (the 'allocation') is distributed or recovered. It covers both looped and non-looped (radial) interconnectors. For looped interconnectors, the first step is to determine the net loop allocation (that is, the net IRSR for the whole loop) for the trading interval using the allocations for all the directional interconnectors in the loop determined by AEMO under the allocation methodology. Where the net loop allocation is a positive amount, the net trade methodology applies to determine how much is distributed to the holders of SRD units for the looped interconnectors or (if there is any unsold settlements residue amount), to the CNSP for the importing region. Where the net loop allocation is negative, it is recovered from the CNSPs in the looped regions in proportion to the regional share of demand. For directional interconnectors that are not looped interconnectors, where the allocation is a positive amount, AEMO distributes it to SRD unit holders for the relevant directional interconnector or, if there is any unsold settlements residue amount, to the CNSP for the importing region. Where the allocation is negative, it is recovered from the CNSP for the importing region. In both cases, AEMO uses positive IRSR to recover auction expense fees before making any distribution.
3.6.6(a)	New clause 3.6.6(a) defines the key concepts used for the calculations that determine how the settlements residue allocations for directional interconnectors are distributed or recovered.
3.6.6(b)	New clause 3.6.6(b) provides for distribution of the IRSR allocation to looped interconnectors when the net loop allocation is positive. Consistent with current rule 3.18, AEMO first uses it to recover auction expense fees. Next, for each directional interconnector in the loop, AEMO distributes the net trade amount to SRD unit holders to the extent of their unit entitlement, and any unsold settlements residue amount is distributed to the relevant CNSP. The net trade amount calculations are explained below.
3.6.6(c)	New clause 3.6.6(c) provides for the recovery of the IRSR allocation to looped interconnectors when the net loop allocation is negative. AEMO must recover the amount from the CNSP for each region in the loop according to the regional share (with 'regional share' defined in new clause 3.6.6(a)). The regional share is determined in clause 3.6.6(c) for each billing period, and reflects the region's share of regional demand across all three regions in the loop in the twelve months ending with that billing period.
3.6.6(d)	New clause 3.6.6(d) explains how the IRSR allocation to a directional interconnector that is not a looped interconnector is distributed when it is positive.

Clause	Description of final rule
	Consistent with the current rules, AEMO first uses it to recover auction expense fees, then distributes it to the relevant SRD unit holders to the extent of their unit entitlement, and, if there is any unsold settlements residue amount, distributes it to the CNSP for the importing region. This clause replaces old clause 3.18.1(d) (with respect to auction fees and payments to SRD unit holders) and clause 3.18.4(a)(2) (with respect to distribution of the unsold settlements residue amount).
3.6.6(e)	New clause 3.6.6(e) provides for the recovery of the IRSR allocation to a directional interconnector that is not a looped interconnector when it is negative. AEMO must recover the amount from the CNSP for the importing region. This clause replaces old clause 3.6.5(a)(4).
3.6.6(f) - (h)	New clauses 3.6.6(f) to (h) are the first stage of the net trade calculations and result in the determination of the net trade quantities for looped interconnectors. The provisions use concepts defined in clause 3.6.6(a), in particular 'notional interconnector', 'net exporting region', 'net regional export quantity' and the terms 'notional interconnector export flow' and 'notional interconnector import flow'. The term 'notional interconnector' is from the allocation methodology and, in general terms, refers to the transmission assets, including a regulated interconnector, that link the RRNs of two regions. AEMO uses the notional interconnector concept under the allocation methodology to account for losses between the RRNs. The notional interconnector amounts are then used to calculate the IRSR allocation to each directional interconnector. Refer to clauses 1.4, 2.1 and 3.1 of the allocation methodology. For calculation of the net trade quantities, the starting point is to determine, for each looped region, the notional interconnector export flow and notional interconnector import flow for each of the region's notional interconnectors. These can be thought of as flows from or to the region over regulated interconnectors but calculated at the region's RRN by adjusting for losses. They correspond to the notation EXP and IMP in AEMO's allocation methodology. To illustrate, for a notional interconnector between regions A and B where the flow in a trading interval is from A to B, EXP represents the flow into the notional interconnector at the RRN in region A and IMP represents the flow out of the notional interconnector at the RRN in region B. IMP at the RRN in region A for that notional interconnector will be zero for the trading interval, and EXP at the RRN in region B for that notional interconnector will also be zero for the trading interval. The next step is to calculate the net regional export quantity for each looped region. This is the difference between the region's notional interconnector export flows (the sum of each value of EXP at the RRN) and region's notional interconnector import flows (the sum of each IMP at the RRN), but only for the interconnectors forming part of the loop. For example, a looped region A may have three notional interconnectors that form part of the loop (two to region B and one to region C) and a fourth (to region D) that does not. The values of EXP and IMP at the RRN in region A that relate to

Clause	Description of final rule
	flows on the fourth notional interconnector to region D will be ignored when calculating the net regional export quantity for region A. The next step is to determine which of the looped regions is a net exporting region. This will be the case where it has a net regional export quantity that is positive or zero. Once this has been determined, one of clauses 3.6.6(f), (g) or (h) will be used to determine the net trade quantity (in MWh) for each looped interconnector. Paragraph (f) applies if only one of the three looped regions is a net exporting region and paragraph (g) applies if two are net exporting regions. In both cases, a net trade quantity is calculated for two of the six looped interconnectors and is zero for the remaining four. In the rare cases where (due to the effect of losses) there are three net exporting regions, a net trade quantity is calculated for three of the six looped interconnectors in the direction of flow around the loop, and is zero for the remaining three. This is covered by clause 3.6.6(h).
3.6.6(i) and (j)	New clauses 3.6.6(i) and (j) are the final step in the net trade calculations and result in the determination of the provisional net trade amount and the net trade amount for each looped interconnector. The provisional net trade amount, calculated in paragraph (i), is the amount allocated to each looped interconnector before secondary netting. The starting point for the provisional net trade amount is to calculate the notional amount attributable to the looped interconnector ('NA' in the calculation) by multiplying the net trade quantity for the looped interconnector by the difference in the RRP between the importing region and the exporting region. The notional amount may be negative. It will also be zero in many cases, potentially because the price difference is zero, but also for the looped interconnectors that have a net trade quantity of zero. The provisional net trade amount - which can also be positive, negative or zero - for a looped interconnector is a share of the net loop allocation proportional to the notional amount for the looped interconnector divided by the total of the notional amounts. Using a proportionate share of the net loop allocation accounts for transmission losses by ensuring that the total of the provisional net trade amounts is equal to the net loop allocation. As a very simplified example, assume a net positive IRSR of $100, with one arm of the loop having a counter-price flow with an NA value of -$20 and the other an NA value of $30. The provisional net trade amount for the first arm will be -$200 and for the second, $300. The final step in paragraph (j) is to apply secondary netting. For a looped interconnector with a positive provisional net trade amount, the net trade amount is its proportionate share of the net loop allocation. This is calculated by dividing the provisional net trade amount by the sum of the positive provisional net trade amounts, multiplied by the net loop allocation. The result will be positive or zero. For looped interconnectors with a negative or provisional net trade amount, the net trade amount is zero.

Clause	Description of final rule
	Taking the simplified example above, the net trade amount for the first arm will be zero, and for the second, $100.
3.6.6(k) and 3.13.4	New clause 3.6.6(k) introduces new reporting requirements covering: • for each looped region, the net regional export quantity • for each directional interconnector, the settlements residue allocated to each directional interconnector (the 'allocation') • for each looped interconnector, the net trade quantity, the provisional net trade amount, and the net trade amount. The provision has been placed in clause 3.6.6 because it uses terms that are defined locally in paragraph (a). A cross-reference to clause 3.6.6(k) has been included in clause 3.13.4(n) to assist navigating daily reporting requirements under the NER.
3.8.1(e) and 3.8.9(c)	The amendments correct minor typographical errors in these provisions.
3.8.10(c)	The amendment removes a redundant reference to the first date for publication of the network constraint formulation guidelines and corrects a minor typographical error.
3.13.5A	Current clause 3.13.5A contains reporting requirements for the SRA. As explained in section 3.4, the final rule expands these reporting requirements to include more information about the number of units sold, secondary trading, payouts to SRD unit holders and information about provisional net trade amounts and amounts recovered from CNSPs. Therefore, this clause is also retitled to reflect the expanded reporting on settlements residue more broadly.
3.15.1(a)(3)	The final rule removes the reference to 'negative' settlements residue in this clause since clause 3.6.5 deals with both positive and negative IRSR.
3.18.1(c) and (d)	The final rule deletes clause 3.18.1(d) since it has been replaced by clause 3.6.6. The note at clause 3.18.1(c) is intended to assist with navigation to clause 3.6.6.
3.18.3(a1)(3)	A minor typographical error has been corrected.
3.18.4(a)	Clause 3.18.4(a) has been amended to remove what was formerly subparagraph (2) since clause 3.6.6 now deals with the distribution of unsold settlements residue amounts. Out of date cross-references to clause 3.6.5 have also been removed and the heading has been updated.
3.18.4(c)	Consequential amendments reflect the removal of clause 3.18.1(d) and update the drafting to use the correct defined term.
3.18.4A(d)(1)	The drafting has been updated to use the correct defined term.
3.18.4A(d)(2)	Consequential amendments allow for the introduction of clause 3.6.6 and the different arrangements for recovering negative IRSR as between looped and radial interconnectors.
6A.23.3(b)(1) and 6A.23.3(e)(2)	Clause 6A.23.3(b)(1) deals with adjustments in the transmission pricing process for auction proceeds and unsold settlements residue amounts. Clause 6A.23.3(e)(2) deals with adjustments in the transmission pricing process for IRSR. The drafting of both provisions has been updated, including for the new clause references and to use the correct defined terms.

Clause	Description of final rule
Chapter 10 global definitions	**Definitions of 'importing region' and 'exporting region'** The new defined terms allow for the importing region or exporting region to be identified for a physical interconnector or for a directional interconnector, as required for the context in which the term is used. **Definition of 'regulated interconnector'** The existing term has been amended to correct drafting and also to add a new limb covering new interconnectors developed as actionable ISP projects. A second new limb has been added to refer to the interconnectors deemed to be regulated interconnectors by Chapter 9 of the NER. Paragraph (c) of the definition captures PEC - see also clause 11.188.4(c).
11.188	The transitional arrangements are in new rule 11.188. They are explained in chapter 4.

Source: AEMC.

F Summary of other issues raised in submissions

Table F.1: Summary of other issues raised in submissions

Stakeholder	Issue	Response
AEC (p.1), AFMA (p.1, pp.7-8), AGL (pp.2-3), Alinta Energy (pp.1-2, 6), Delta (p.1), EnergyAustralia (p.1, p.4), ENGIE (pp.1-3), Snowy Hydro (p.1), Stanwell (p.2), Origin (p.9), Alinta Energy letter - received 9 September 2025 (pp.1-3).	Several stakeholders expressed concerns with how the AEMC has conducted the rule change process in submissions to the directions paper. The key points raised by stakeholders were: • The directions paper marked a significant shift from the draft determination, without sufficient consultation (such as an options paper between the draft determination and the directions paper). • The AEMC did not sufficiently consider AEMO's previous consultation process (that being, AEMO's PEC Market Integration Papers) in proposing the directions paper approach. AEMO's process had previously ruled out netting off as an option because it considered this "aligns with regulatory precedent and would limit the impact on SRA processes and units" (see source note 1). • The AEMC did not allow enough time for consultation on the directions paper (three weeks). • The AEMC failed to adequately consider TNSP cash flow issues at the draft determination stage, resulting in limited time to resolve these issues through the directions paper and final determination. These would be better considered in a separate review.	Section 1.2 and appendix A outline the key steps in the process the Commission has followed for this rule change process, including those required to meet the statutory requirements. The draft determination and directions paper were valuable in refining our understanding of the issues related to, and options for, managing IRSR in transmission loops. The Commission started engaging with stakeholders on the proposed change in direction from the draft determination in April 2025. It has continued to do so throughout the rule change process, through formal consultation, industry engagement and bilateral discussions. We note that in its directions paper for the PEC integration project, AEMO contemplated the possibility that the Commission might decide to adopt a netting approach in this rule change process and explained how it would deal with cancellation of SRD units already on issue, were that to occur. The Commission is satisfied that it has appropriately considered and taken into account CNSP cash flow issues based on information provided to the Commission and our own analysis.

Stakeholder	Issue	Response
	• The directions paper proposal was 'premature' and placed too much weight on CNSPs' concerns which had not been tested. In contrast, the draft determination had taken a more balanced approach to the issues raised in the rule change request - an approach that was supported by the majority of stakeholders. • The directions paper proposal directly contradicts much of the AEMC's rationale for how it assessed its recommendations in the draft determination. • The AEMC did not sufficiently consider alternative options to netting in its directions paper.	
Origin (pp.1, 3, 7, 10).	In its submission to the directions paper, Origin suggested that the AEMC did not provide an evidence-based comparison or analysis of the full costs and trade-offs of all options raised.	As noted throughout the body of this final determination, there has never been a transmission loop in the NEM and we cannot be sure of IRSR outcomes around the loop until it is in operation as we do not have operational data or experience to work with. Refer to the in-depth options analysis included in section 2.4.6. For this, we used the data and analysis we have available, alongside economic theory and information provided by stakeholders to make a decision on what approach to managing IRSR is most likely to promote the NEO. Our data and analysis includes that set out in the draft determination, directions paper and this final determination and its appendices, as well as analysis conducted by ACIL Allen in its paper 'Modelling the settlement effects of Project Energy Connect', July 2023. We also note that the future review canvassed in chapter 5 of the final determination will provide an opportunity to review the arrangements with operational data available.

Stakeholder	Issue	Response
Origin (p.7), AFMA (p.2), Snowy Hydro (p.2).	In submissions to the directions paper, these stakeholders noted that negative IRSR is an inevitable cost related to the regional pricing structure of the NEM, and that this cost has to be recovered somehow. Origin noted that "the policy focus should be on ensuring these costs are allocated to reflect the broader benefits of loop flows, while preserving risk management tools such as SRD units."	The AEMC agrees that negative IRSR - as well as positive IRSR - is an inevitable consequence of a regional pricing model. This final determination explains (in section 2.4.1) how IRSR behaves differently in loops compared to radial interconnectors and the different options for managing IRSR in loops. The Commission is satisfied that the net trade approach is likely to better contribute to the NEO than the other options it considered. As discussed in section 4.3.1 of the directions paper, it is difficult to make assumptions about where the costs and benefits fall without seeing the loop in operation. We agree with these stakeholders that the cost of negative IRSR needs to be recovered from some party, and this rule change considers the party best placed to manage IRSR. Our reasoning and analysis that was used to determine this is elaborated in further detail in section 2.4 of the final determination.
AFMA (p.3), Delta (p.1), Snowy Hydro (p.1), Origin (p.6).	In submissions to the directions paper, these stakeholders suggested that netting would reduce the visibility of costs passed through to consumers (compared with the existing approach, which includes costs passed through to consumers in transmission pricing). Snowy Hydro noted that "the Commission neglects to mention that this [directions paper] approach makes it less transparent as it would become another component of the wholesale cost of energy resulting from retailers having less efficient hedging costs."	We consider that any potential transparency benefits of passing negative IRSR through CNSPs to consumers do not outweigh the costs and risks to consumers outlined in section 2.4. Reporting arrangements in the final rule will promote sufficient transparency - and greater transparency than can be provided through transmission pricing - on how much positive and negative IRSR arises in the loop and how it is distributed to SRD unit holders and CNSPs.
EnergyAustralia (p.3), Stanwell (p.2).	In submissions to the directions paper, these stakeholders suggested that CNSP exposure to negative IRSR (which would occur under the status quo arrangements, AEMO's	The Commission notes that although TNSPs have some influence on the timing of planned outages, the vast majority of negative IRSR is out of their control. Negative IRSR is not necessarily related to

Stakeholder	Issue	Response
	rule change proposal and our draft determination proposal) would appropriately incentivise them to minimise the impact of network outages on efficient dispatch.	outages, as constraints on the network exist even when all elements are in service. This will be more the case when the loop is in operation because negative IRSR will frequently arise as part of normal operation due to the spring washer effect. Therefore, we consider that IRSR allocation is not the right policy mechanism to encourage the minimisation of impacts of network outages. We do not consider CNSPs are the appropriate party to manage all negative IRSR arising around the loop, as discussed in detail in section 2.4 of this final determination.
EUAA (p.4)	The EUAA considered that some existing shortcomings of the clamping process would be exacerbated by the introduction of a transmission loop, and warranted "urgent review". Although it acknowledged that AEMO is currently consulting on these issues, the EUAA considered that these issues should instead be "addressed through a rule change, to ensure that future [clamping] procedures and guidelines meet the requirements of the NEO".	As part of this rule change process, we considered the clamping arrangements that AEMO intends to apply to the loop and determined it is appropriate for clamping to remain at AEMO's discretion. The Commission notes that the EUAA raised these issues in response to AEMO's Consultation on Automation of Negative Residue Management for the implementation of transmission loops process (see source note 2), which is currently in progress, with a draft report out for consultation. The Commission encourages the EUAA, and the broader industry, to continue engagement with AEMO's process. The Commission will consider any rule change requests it receives regarding clamping in future, as per its usual processes.

Source: Note 1: AEMO's rule change request, pp.4-5, and AEMO, Project Energy Connect Implementation - Directions Paper, section 2.4, p.14. Note 2: EUAA, submission to AEMO's consultation paper on automation of negative residue management for the implementation of transmission loop, p.2.

Abbreviations and defined terms

ACE	Adjusted consumed energy
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ARD	Annual regional demand
Commission	See AEMC
CNSP	Co-ordinating Network Service Provider
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
EUAA	Energy Users Association of Australia
FERM	Firm Energy Reliability Mechanism
IRSR	Inter-regional settlements residue
MMS	Market Management System
MW	Megawatt/s
MWh	Megawatt hour/s
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
NRM	Negative residue management
NSW	New South Wales
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
NTP	National Transmission Planner
PEC	Project EnergyConnect Stage 2
Proponent	The individual / organisation who submits a rule change request to the Commission
Q	Quarter
RRN	Regional reference node
RRO	Retailer Reliability Obligation
RRP	Regional reference price
SA	South Australia
SRA	Settlements residue auction
SRD	Settlements residue distribution
TNSP	Transmission Network Service Provider
TRD	Total regional demand
VNI	Victoria-NSW Interconnector
WACC	Weighted average cost of capital