AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Draft rule determination

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

Proponent

Australian Energy Market Operator

12 December 2024

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About the AEMC

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.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Executive summary

1 The Commission has decided to make a more preferable draft rule (draft rule) for allocating negative inter-regional settlements residue (IRSR) in transmission loops in response to the rule change request submitted by the Australian Energy Market Operator (AEMO). The draft rule would more effectively manage the consumer risks of unpredictable negative IRSR by sharing it broadly amongst all looped regions, in proportion to regional demand. The draft rule would commence on 3 July 2025.

2 A transmission loop will be formed in the National Electricity Market (NEM) when Project EnergyConnect Stage 2 (PEC) becomes operational. PEC - currently under construction - will be the first interconnector between New South Wales and South Australia. The draft rule would apply to the transmission loop consisting of PEC and the existing VNI, Heywood and Murraylink interconnectors and any future transmission loops with similar characteristics.

3 The existing arrangements for the allocation of positive IRSR and the settlements residue auctions (SRA) would continue to apply for transmission loops. However, the Commission considers there is a case to review whether SRA arrangements are providing the best outcomes for consumers and market participants more broadly, which is beyond the scope of this rule change request. We intend to conduct this review in 2025-26, subject to our annual prioritisation process.

4 This draft determination explains how the draft rule would operate and the Commission's rationale for making the draft rule. We are seeking stakeholder feedback on our draft determination and rule by **30 January 2025**.

The draft rule would create a new allocation method for negative IRSR in transmission loops

5 This rule change is concerned with how to manage and distribute IRSR in transmission loops. In a transmission loop, negative IRSR is expected to occur more often and may be large and unpredictable. This large and unpredictable negative IRSR poses financial risks to consumers and transmission network service providers (TNSP).

6 Our draft rule would address these risks by sharing negative IRSR between all regions in the loop (New South Wales, South Australia, and Victoria). Negative IRSR would be allocated to TNSPs in proportion to regional demand, and then recovered from customers via transmission charges. This allocation method manages the risk for all parties by spreading it widely.

7 This is a more preferable draft rule. AEMO's rule change request proposed reallocating negative IRSR to other arms of the loop that are accruing positive IRSR in the same dispatch interval, when net IRSR for the loop is positive. We consider the draft rule would manage risk more effectively than AEMO's proposal as well as providing more stable and cost-reflective outcomes. Therefore, it would promote the National Electricity Objective (NEO) more effectively.[1]

1 Section 7 of the National Electricity Law (NEL).

8 PEC will help facilitate the transition to net zero by enabling future renewable projects to connect to the grid and supply energy to multiple regions. It is expected to deliver consumer benefits including increased inter-regional trade, reduced emissions, increased competition, and improved pricing outcomes. Our draft rule would support the efficient operation of transmission loops and the realisation of these consumer benefits by:

- allocating negative IRSR appropriately and managing the risks associated with it,
- maintaining an SRA framework that can support inter-regional hedging, trade and competition,
- not imposing additional clamping requirements, and supporting AEMO's intended approach to clamping in the loop.

The Commission has considered stakeholder feedback and the risk of unpredictable negative IRSR in making its decision

9 Stakeholder feedback has influenced our decision by highlighting the potential impacts on different stakeholders. Feedback from TNSPs emphasised the cash flow challenges that could arise from unpredictable negative IRSR, depending on how it is allocated, and how this in turn could impact customer pricing. Market participants considered it was important to maintain the value of settlements residue distribution (SRD) units for inter-regional hedging, noting that inter-regional trade also benefits consumers.

10 Several stakeholders responded to our consultation paper's suggestion that the existing arrangements might still be appropriate for transmission loops. These stakeholders, including AEMO, considered the analysis should take into account other factors apart from wholesale pricing outcomes in the loop, especially since consumers are not directly exposed to wholesale prices.

11 The draft rule takes this feedback into account given it would spread the risk of negative IRSR between all looped regions. It would not make changes to SRA arrangements at this time.

We assessed our draft rule against three assessment criteria

12 The Commission has considered the NEO and the issues raised in the rule change request and assessed the draft rule against three assessment criteria. We gathered stakeholder feedback and undertook regulatory impact analysis in relation to these criteria.

13 The more preferable draft rule would contribute to achieving the NEO by:

- **Creating better outcomes for consumers |** The draft rule would mitigate the risks posed to consumers by large, unpredictable negative IRSR. Allocating negative IRSR to all looped regions according to regional demand would reduce bill volatility and reduce the maximum potential cost for a customer in any region.
- **Aligning with principles of market efficiency |** The draft rule would seek to create an appropriate allocation of costs and risks. Allocating negative IRSR in proportion to regional demand (that is, electrical energy consumption) would align consumers' costs with the benefits they receive. This allocation method would also help manage cash flow risks for TNSPs by reducing the volatility, and maximum size, of the amount recovered from the TNSP in each region.
- **Aligning with principles of good regulatory practice |** The draft rule would provide stable and predictable outcomes because it would allocate negative IRSR according to a simple, infrequently changing ratio in all circumstances. This also means the draft rule would be simple to implement, reducing costs for AEMO and TNSPs.

The draft rule would share negative IRSR amongst all looped regions

14 In this rule change, we considered the allocation of negative IRSR, the allocation of positive IRSR, and the application of clamping (negative residue management) for transmission loops.

AEMO's intended clamping approach would allow more negative IRSR to accrue in the loop

15 In its rule change request, AEMO proposed an approach to clamping in transmission loops where counter-price flows would only be clamped if the net IRSR for the loop is negative. This is because counter-price flows that occur when net IRSR is positive are likely to support overall efficient outcomes. The Commission agrees with this approach, noting AEMO can implement it via procedure updates, with no need for a rule change. The Commission understands that AEMO still intends to approach clamping in this way.

16 In a transmission loop, negative IRSR is likely to occur more frequently and in greater amounts. This is due to the behaviour of loop flows when the 'spring washer effect' arises, combined with AEMO's proposed approach to clamping. The Commission has developed the draft rule in light of this potential for larger and more frequent negative IRSR.

Negative IRSR would be allocated to each region in proportion to regional demand

17 Under the draft rule, all negative IRSR that accrues on an interconnector in a transmission loop would be allocated amongst all three looped regions in proportion to regional demand. This would apply regardless of whether net loop IRSR is positive or negative. For the purposes of the draft rule, 'regional demand' means each region's total annual electricity consumption over the prior year.

18 Consistent with the current arrangements, AEMO would initially recover negative IRSR from the TNSP in each region. Negative IRSR would then flow through to customers via increased transmission charges.

There would be no changes to SRAs or the allocation of positive IRSR

19 Our draft determination is to retain the existing arrangements for the allocation of positive IRSR, including the SRA framework. We considered how these arrangements would apply to transmission loops and whether they would remain appropriate. While we have identified some potential issues with SRAs, we have chosen not to change SRA arrangements in this rule change due to scope and timeframe limitations. However, we intend to explore those issues in a broader review as outlined below.

The draft rule would take effect upon creation of the transmission loop

20 The draft rule would commence on 3 July 2025, to align with the commencement of the *Providing flexibility in the allocation of interconnector costs* rule. However, the draft rule would not come into practical effect until the transmission loop is incorporated into the National Electricity Market Dispatch Engine (NEMDE). This is expected to be in Q4 2026, at which time PEC will be operating at partial capacity. The full capacity of 800 MW is expected to be released in late 2027. These dates are based on current testing and commissioning timelines and are subject to change.

21 Following the final determination, AEMO would carry out implementation work for the integration of PEC into the NEM. There will be sufficient time between the commencement of the final rule and the creation of the loop in NEMDE for AEMO to complete the necessary system updates and procedure updates. The final determination would provide certainty for AEMO to progress this work.

The Commission intends to review SRA arrangements in 2025-26

22 Beyond the scope of this rule change, the Commission considers that there is a case to review whether the current SRA arrangements are in the long-term interests of consumers because IRSR will become more frequent in transmission loops, exacerbating issues with negative IRSR. Current arrangements allow hedging of the positive IRSR but not negative IRSR, which leaves consumers exposed to the entire risk of negative IRSR. The Commission's initial view is that there could be benefits to consumers and generators from being able to hedge movements in negative IRSR.

23 It is also not apparent that positive hedging delivers the value to consumers that SRAs were designed for, which includes competition between regions from which consumers benefit through more competitive pricing.

24 Based on our current work program, we intend to conduct this review in 2025-26, subject to the outcomes of our annual prioritisation process. In broad terms, we expect the review could cover:

- whether the sale of SRD units through SRAs represents good value for consumers, and whether and how value might be improved,
- whether the SRD units are designed in a manner that best enables market participants to manage inter-regional price risk, and consumers to best manage IRSR risk,
- the arrangements for SRD units and SRAs for all regulated interconnectors in the NEM, whether or not they form part of a transmission loop,
- the efficiency of the current arrangements for managing IRSR cash flows, for example whether cash owed to consumers could move through to consumers more quickly and/or whether the cash flow impost on TNSPs can be reduced.

25 We welcome stakeholder feedback on the concept and scope of this proposed review.

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this draft determination and rule must be lodged with Commission by **30 January 2025.**

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0386.**[2]

Tips for making submissions on rule change requests are available on our website.[3]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[4]

Next steps and opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions.

You can also request the Commission to hold a public hearing in relation to this draft rule determination.[5]

Due date: Requests for a hearing must be lodged with the Commission by 6 January 2025.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0386.** Specify in the comment field that you are requesting a hearing rather than making a submission.[6]

For more information, you can contact us

Please contact the project leader with questions or feedback at any stage.

Project leader:	Madeleine Hartley
Email:	madeleine.hartley@aemc.gov.au
Telephone:	02 8296 7816

2 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

3 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

4 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission.

5 Section 101(1a) of the NEL.

6 If you are not able to lodge a request online, please contact us and we will provide instructions for alternative methods to lodge the request.

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This draft determination is to make a more preferable draft rule (draft 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. We are seeking feedback on this draft determination and draft rule.

For more detailed information on:

- why we made the draft rule, refer to chapter 2,
- how our draft rule would work, refer to chapter 3,
- our intent to review IRSR and settlements residue auctions (SRA) arrangements more broadly in the future, refer to chapter 4.

1.1 Our draft rule would allocate negative IRSR to regions in transmission loops according to regional demand

Project EnergyConnect Stage 2 (PEC) will be a new interconnector linking South Australia and NSW, which is expected to be operating at full capacity by late 2027.[7] PEC will create the first inter-regional transmission loop in the National Electricity Market (NEM), along with the existing Heywood (VIC-SA) and VNI (NSW-VIC) interconnectors.

In inter-regional transmission loops, IRSR is expected to arise more frequently than it does across 'radial' interconnectors (that is, the current regulated interconnectors that link two regions without forming part of an inter-regional transmission loop). This is due to the way that power flows in a transmission loop, and how this interacts with the NEM's regional pricing model.

AEMO submitted a rule change request in February 2024 proposing new arrangements for managing negative IRSR in transmission loops.[8] In transmission loops, negative IRSR can accrue on one or two 'arms' (or directional interconnectors) of the loop, while the net IRSR for the loop as a whole is positive. This is a normal outcome of efficient dispatch in a loop due to the spring washer effect.[9] These impacts are outlined in AEMO's rule change proposal and section 2.2 of our consultation paper. Modelling commissioned by AEMO suggests that this will be a common outcome for the PEC transmission loop.[10]

To ensure that benefits flow to consumers from constructing and energising PEC (and other related transmission infrastructure), AEMO proposed it would not 'clamp' looped interconnectors to limit negative IRSR when 'net' loop IRSR is positive. Clamping would reduce the overall benefits of PEC by restricting the flow of electricity over the interconnector until negative IRSR is below the predefined threshold set by AEMO. The Commission agrees that AEMO's approach to clamping in transmission loops is sensible at the current time and notes implementing it does not require a change to the National Electricity Rules (NER) (see section 3.2.5).

To address the impact of negative IRSR, AEMO proposed amending the NER so that this unclamped negative IRSR would be reallocated to looped interconnectors accruing positive IRSR.

7 https://www.projectenergyconnect.com.au.

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

9 Due to electrical circuit physics, 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 taking an alternative route around the loop to satisfy the laws of the physics. See appendix C.3.1.

10 ACIL Allen, 'Modelling the settlement effects of Project Energy Connect', July 2023, https://aemo.com.au/en/consultations/current-and-closedconsultations/project-energy-connect-market-integration-paper (ACIL Allen, 'Modelling the settlement effects of PEC').

This would be a change from the current allocation of negative IRSR to the importing region. AEMO considered its proposal would better align the costs of the loop with beneficiaries (see chapter 3). AEMO proposed no changes to the arrangements for positive IRSR or the associated SRA.

We have made a more preferable draft rule that we consider would achieve better outcomes for consumers and meet the national electricity objective (see chapter 2). For inter-regional transmission loops, our draft rule would allocate:

- all negative IRSR by 'regional demand' - i.e. by the share of electrical energy used in each region over the prior year. This would apply for both positive and negative 'net' loop IRSR.
- all positive IRSR as per current arrangements - positive IRSR allocated to settlements residue distribution (SRD) unit holders, but the proceeds of SRAs go to the transmission network service provider (TNSP) of the importing region.

Our draft rule would make no changes to IRSR arrangements for radial interconnectors.

See chapter 3 for a detailed description of our draft rule.

1.2 Our draft rule was shaped by stakeholder feedback and our consideration of the risk of unpredictable negative IRSR

Our proposed approach in the draft rule has been shaped by four key areas of stakeholder feedback to our consultation paper, as well as modelling undertaken by AEMO and our own analysis.

1.2.1 Stakeholders disagreed that the status quo approach may best align IRSR with price impacts for consumers

The Commission presented analysis in our consultation paper that suggested that the 'status quo' allocation of negative IRSR (that is, allocation to the importing region) could be the best allocation method for aligning IRSR incidence with the impacts of the loop on wholesale price outcomes for consumers.

Stakeholders did not agree with this analysis, noting that consumers are not directly exposed to wholesale prices.[11] Many stakeholders cautioned against assessing wholesale pricing outcomes around the loop as a method of analysing IRSR impacts, noting that consumer bills include other costs (see chapter 2).[12] AEMO considered that "there may be no relationship between negative residues and wholesale prices when averaged over time".[13] Stakeholder submissions to our consultation paper were overall supportive of AEMO's rule change proposal, as compared to the 'status quo' and other alternative options we discussed in the paper.[14]

While we would expect wholesale prices and contract prices to be correlated over time, the Commission did not investigate this issue further because we turned our attention to a more fundamental risk that needed to be addressed (see chapter 3). Our further analysis identified the risk of extreme unexpected negative IRSR events and its potential impacts to consumers (see section 3.2.2). Ultimately, our proposed allocation method is based on our further consideration of this and a number of other matters, including TNSP cash flow implications (see section 1.2.2).

11 Submissions to the consultation paper: Australian Energy Council (AEC), p.2; Origin Energy, p.3; AEMO, p.6; Engie, p.3.

12 Submissions to the consultation paper: AEC, p. 2; Engie, p 2; Origin Energy, p. 2.

13 AEMO submission to the consultation paper, p. 9.

14 Submissions to the consultation paper: AEC, p. 1; AGL, p.2; Engie, p.2; Shell Energy, p. 3.

1.2.2 TNSPs asked to spread the cost of negative IRSR between regions

TNSP feedback to the consultation paper emphasised that more frequent and unpredictable negative IRSR arising from transmission loops can cause cash flow issues for TNSPs that flow through to impacts on consumers. The Energy Networks Australia (ENA) submission to the consultation paper highlighted the potential issues arising from up to two years' delay between forecasting and recovering any 'true-ups' for actual negative IRSR through transmission use of service (TUOS) charges.[15]

Consumers ultimately bear the cost of negative IRSR, as costs of negative IRSR are passed to consumers through increased TUOS charges. Consumers could be impacted by both increased negative IRSR, and volatility in IRSR between billing years (or as a result of TNSP 'true-ups').

In response to these concerns, we conducted further analysis that shows the possibility of extreme negative IRSR arising in transmission loops with overall net positive outcomes. The Commission considers that this risk needs to be managed (see section 3.2.2). Our draft rule would therefore spread the cost of negative IRSR between all looped regions, in order to share the impacts of unpredictable and potentially large negative IRSR between TNSPs, and therefore between consumers.

1.2.3 Market participants want the value of SRD units maintained

Submissions from the Australian Financial Markets Association (AFMA) and SRA participants prioritised the importance of maintaining the 'firmness' and hedging value of SRD units - the units sold in SRAs.[16]

SRA participants consider that SRD units are an important way to manage risk and promote inter-regional trade. We recognise that these are important benefits of SRD units. However, we are concerned that the current rules only allow for the risk of positive price separation to be hedged, which creates an almost unlimited liability from negative IRSR for consumers that is difficult to manage. This means that consumer prices may be less reflective of underlying market expectations and that SRAs may not be producing good consumer outcomes. Further, as outlined in the consultation paper, settlement residues have significantly exceeded auction proceeds on average over the past 20 years.

The Commission is interested in exploring this issue. We therefore intend to conduct a review into the arrangements for managing both negative and positive IRSR across all transmission configurations (i.e. looped and radial), likely in 2025-26 (see chapter 4).

1.2.4 Stakeholders recommended a future review of the rules as they operate in PEC

AEMO's prior work and our consultation paper both note that the frequency and magnitude of negative IRSR in transmission loops is difficult to model and presents an unknown risk. The impacts on consumers in looped regions could be high and unpredictable, even when the loop is accruing overall net positive outcomes (indicating overall consumer benefits).

Stakeholders recommended that we monitor and review transmission loop IRSR outcomes after PEC begins operating.[17] This would provide useful data on IRSR in transmission loops that could help inform the best approach to IRSR. The Commission notes that existing AEMO reporting requirements and AEMO monitoring powers can provide transparency over loop outcomes (see

15 ENA submission to the consultation paper, pp. 1-2.

16 Submissions to the consultation paper: AFMA, p. 2; Snowy Hydro, p. 2; Shell Energy, p. 2; Origin Energy, p. 1.

17 Submissions to the consultation paper: AGL, p. 2; Engie, p. 1; AEC, p. 2; Justice and Equity Centre (JEC), p. 1.

section 3.5). Rather than a loop-specific review, we consider that a broader review of SRAs across the whole NEM would be more valuable (see chapter 4).

1.3 Our draft rule would support consumer outcomes in transmission loops

Transmission infrastructure is a critical enabler of new low-cost generation and for the transition to net zero. PEC will help facilitate the transition by enabling future renewable projects to connect to the grid and supply energy into the network.

Stakeholders commented on the importance of ensuring the greatest possible benefits of PEC for consumers.[18] This includes greater integration of renewable energy into the NEM (which is particularly important for South Australia) and increased inter-regional trade and contracting liquidity benefits for all looped regions. Consumers also benefit from reduced emissions, increased competition in the NEM, and improved security, reliability, and pricing outcomes.

Our draft rule would support PEC to achieve these benefits. In accordance with AEMO's proposal, we do not propose to limit the efficient operation of the loop through clamping. Rather, the draft rule would create arrangements to share the resulting negative IRSR between all looped regions, with a view to balancing the potential risk to consumers with the overall benefits of the transmission loop.

18 Submissions to the consultation paper: AEC, p. 2; Alinta Energy, p. 2; AGL, p. 2.

2 The draft rule would contribute to the energy objectives

The Commission has made a more preferable draft rule to allocate negative IRSR in transmission loops according to regional demand. This allocation method would more effectively manage risk and seek to provide stable and cost-reflective outcomes for consumers.

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.[19]

For this rule change, the relevant energy objective is the National Electricity Objective (NEO).

The NEO is:[20]

> 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.[21]

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 is likely to better contribute to the achievement of the NEO.[22]

For this rule change, the Commission has made a more preferable draft rule. The reasons are set out in section 2.3 below.

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

The draft rule would apply in the Northern Territory, as it amends provisions in the NER Chapters 10 and 11, which apply in the Northern Territory. However, these amendments would have no practical effect in the Northern Territory.

19 Section 88(1) of the National Electricity Law (NEL).

20 Section 7 of the NEL.

21 Section 32A(5) of the NEL.

22 Section 91A of the NEL.

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 manage and 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:** We selected outcomes for consumers because 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. Under this criterion, we have considered how the rule change would affect outcomes for consumers (in particular, how changes to electricity pricing and IRSR may impact retail bills) 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 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 are managed for consumers and TNSPs,
    - 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 residues 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 predictability and stable outcomes for consumers.

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request, for impacts within the scope of the NEO. Our reasons for choosing these criteria are set out in section 4.2 of the consultation paper.

The Commission has undertaken regulatory impact analysis to evaluate the impacts of the various policy options against the assessment criteria. Appendix B outlines the methodology of the regulatory impact analysis.

The rest of this section explains why the draft rule best promotes the long-term interest of consumers when compared to other options (including the proposed rule) and assessed against the criteria.

2.3.1 We have considered stakeholder feedback about applying the criteria

In submissions to the consultation paper, most stakeholders broadly agreed with the assessment criteria.[23] Some stakeholders provided feedback on what specific things the criteria should cover.

- Several stakeholders noted that consumer outcomes should be considered holistically and should take into account negative IRSR, wholesale prices, contract pricing, how SRAs benefit consumers, and other factors.[24] The Commission has taken this feedback into account in our draft decision by choosing an allocation method that reflects the broader long-term consumer benefits of the loop, and not only the benefits related to wholesale pricing and/or positive IRSR.
- ENA suggested that the assessment framework should consider how the delayed recovery of negative IRSR through TUOS may undermine the regulatory principles driving cost-reflective transmission pricing.[25] The Commission considers that any issues with the mechanism for recovering negative IRSR from consumers would be better addressed by a separate process, such as our intended review of SRAs.
- AEMO considered that good regulatory practice should include "explicitly considering the analysis and consultation previously performed by AEMO."[26] The Commission appreciates AEMO's work and consultation in compiling the rule change request, and has taken this analysis and consultation into account in our draft decision.[27]
- Origin Energy suggested "adding a criterion that explicitly captures the value of hedging markets" because hedging markets have benefits for consumers.[28] We consider this is sufficiently captured under the principles of market efficiency criterion.

More broadly, the Justice and Equity Centre (JEC) considered that IRSR is a result of a market design failure, being that dispatch settlement and payment settlement use different prices.[29] As noted in our consultation paper, the Commission considers the issue of allocating IRSR in transmission loops should be considered separate to any consideration of broader transmission access reform.[30]

Some stakeholders also gave feedback on how the assessment criteria should be weighted relative to each other.

- AGL considered market efficiency should be prioritised because the efficient allocation of costs and benefits results in good consumer outcomes.[31]
- By contrast, the JEC suggested that the criteria "should be weighted substantially towards outcomes for consumers over theoretical principles of market efficiency" or that the efficiency criterion could be omitted since, in the AEMC's description, it was also linked to consumer outcomes.[32]

While we can weight components of the NEO higher than others in our assessment, in this rule change we consider that it is important to consider all criteria equally due to the overlap and trade-

23 Submissions to the consultation paper: AEC, p. 2; Engie, p. 2; Origin Energy, p. 3; AGL, p. 3.

24 Submissions to the consultation paper: AEC, p. 2; Engie, p. 2; AEMO, p. 6.

25 ENA submission to the consultation paper, p. 4

26 AEMO submission to the consultation paper, p. 6.

27 See AEMO, Project Energy Connect Market Integration Papers, 2022-24, https://aemo.com.au/en/consultations/current-and-closed-consultations/project-energyconnect. See appendix A of our consultation paper for a summary of the feedback AEMO received.

28 Origin Energy submission to the consultation paper, p. 3.

29 JEC submission to the consultation paper, p.2.

30 AEMC, *Inter-regional settlements residue arrangements for transmission loops,* consultation paper, 8 August 2024, section 1.1.4.

31 AGL submission to the consultation paper, p. 3.

32 JEC submission to the consultation paper, p. 2.

offs between them. We have balanced the various elements to develop a draft rule that we consider best serves the long-term interest of consumers, as per the NEO. The Commission's guide to 'How the national energy objectives shape our decisions' explains in more detail how we use assessment criteria to apply the NEO.[33]

2.3.2 The draft rule is likely to create the best outcomes for consumers

The draft rule seeks to provide the best outcomes for consumers as it would spread the costs of negative IRSR as widely as possible, in proportion to electricity consumption. By allocating negative IRSR in proportion to regional demand, the draft rule seeks to mitigate the risks posed to consumers by unpredictable and potentially large amounts of negative IRSR. Since negative IRSR is passed directly through to consumers' retail bills via TUOS charges, it could result in volatile or 'lumpy' customer bills if allocated according to the existing rule or AEMO's proposed method. This is because negative IRSR is recovered from customers in the same year it accrues, or at latest the following year, rather than being smeared over time (see Box 3 in section 3.2.2). However, sharing by regional demand would reduce this impact to the extent possible by spreading the risk amongst all three regions, so that the maximum possible cost for an average consumer in any region is lowered.

2.3.3 The draft rule would provide efficient outcomes, including with regard to risk allocation

Sharing by regional demand best manages the risks

Risk allocation is one of the principles included under our market efficiency criterion. The draft rule would seek to allocate the risks associated with negative IRSR to those parties best suited to manage them. Negative IRSR in the transmission loop may pose a significant financial risk to consumers and TNSPs because it is unpredictable and can be large in magnitude. Section 3.2.2 explains that the resulting cash flow risks could have significant adverse consequences for TNSPs, and flow-on impacts for consumers. Therefore, managing the risk - and placing management of the risk with those best placed to bear the risk - has been a key driver for the draft rule.

Allocation of negative IRSR by regional demand under the draft rule would manage the risk by sharing it between the three regions. This would mean that, in the event of extreme negative IRSR, the amount recovered from any one TNSP would be significantly less than the maximum that could fall to a single TNSP under either the status quo (allocation to importing region) or AEMO's proposed rule. Allocation by regional demand would also provide more diversification than the status quo allocation method or AEMO's proposal. The amount payable by each TNSP would be somewhat less volatile since it would be proportional to the sum of negative IRSR for the whole loop, rather than negative IRSR on one or two directional interconnectors. While cash flow challenges may remain to some extent, we consider that these challenges would be manageable for TNSPs under the draft rule.

See section 3.2.4 for a more detailed analysis.

Sharing by regional demand is more cost-reflective than other options

The draft rule would result in cost-reflective outcomes because it seeks to allocate costs to beneficiaries in the long term. To understand how the transmission loop creates benefits for consumers, it is necessary to consider the whole loop and not just individual interconnectors. Our draft rule would share the costs of negative IRSR amongst all three looped regions, on the basis

33 AEMC, guide to 'How the national energy objectives shape our decisions', 1 August 2024, https://www.aemc.gov.au/regulation/neo.

that consumers in all regions would benefit from the loop. Using regional demand as the sharing metric approximately aligns the costs with consumers' usage of the energy system and hence the benefits they derive from the loop.

AEMO's proposal is designed to align costs (negative IRSR) with benefits (positive IRSR) in each dispatch interval. We consider this approach would not be cost-reflective in practice because the benefits should be considered holistically, and because consumers are not directly exposed to positive IRSR. We also noted in the consultation paper that maintaining the status quo arrangements, where negative IRSR would be allocated directly to the importing region, would align costs (negative IRSR) with benefits (lower wholesale prices). This argument also did not consider the full range of benefits of the loop, or the fact that consumers face expected rather than actual wholesale prices.

See section 3.2.4 for a more detailed analysis.

Consumers are best served by the efficient operation of the loop

Our draft decision would support the efficient operation of transmission loops by maintaining the existing SRA framework and not imposing additional clamping requirements.

The Commission considered imposing an additional requirement for AEMO to clamp extreme negative IRSR in net positive cases, to help mitigate the risks to consumers and TNSPs. However, our draft decision is *not* to impose such a requirement, and to support AEMO's intended approach to clamping.

The transmission loop completed by PEC will provide the greatest benefits to consumers when it is operated efficiently, in the sense of allowing customers in all regions to access the lowest-cost supply. Clamping is a physical constraint applied to address a financial problem facing consumers (i.e. negative IRSR), but it reduces dispatch efficiency by artificially constraining the flows on one or more interconnectors, forcing the dispatch engine to select a higher-cost combination of generation (based on generators' bids). Therefore, it is generally in consumers' interests to minimise clamping. Particularly in circumstances where net IRSR for the loop is positive, the efficiency impacts of clamping would be significant and, together with other risks, would likely outweigh the benefits. See section 3.2.5 for a more detailed analysis.

The Commission agrees with AEMO's proposed approach to clamping, where clamping would only be applied when the net IRSR for the loop is negative. The reasoning for this approach is that net negative outcomes would usually be driven by intra-regional constraints and/or disorderly bidding and are likely to be inefficient.

Interconnection between regions provides the greatest benefits in a market that enables inter-regional trade. The SRA framework provides an important opportunity for inter-regional hedging, which allows market participants to operate across multiple regions at lower risk. This inter-regional trade benefits consumers by increasing competition and lowering prices. Stakeholder feedback strongly emphasised the importance of SRD units and stakeholders generally considered that any changes to the SRA framework would reduce the units' hedging value. This feedback contributed to the Commission's decision to retain the existing SRA arrangements in this rule change, although we intend to review the SRA framework in full in the future. Because of the role of SRD units in supporting inter-regional trade, any changes would need to be thoroughly analysed and consulted on, which was not possible in the scope and timeline of this rule change. See section 3.3.1 and chapter 4 for a more detailed analysis.

2.3.4 The draft rule is consistent with good regulatory practice

The draft rule creates a simple and stable allocation approach for all circumstances

The draft rule would be simple to implement and would result in stable outcomes because it shares negative IRSR between regions according to the ratio of regional demand in all circumstances.

The draft rule would allocate negative IRSR in the same way regardless of whether the net IRSR for the loop is positive, negative, or zero. This is a simpler approach than AEMO's proposal, which involved different allocation methods for net positive and net negative IRSR. This simpler approach would support stable and predictable outcomes by avoiding unexpected step changes in allocation when the net IRSR for the loop moves through zero.

We also considered whether a different allocation method would be warranted for when negative IRSR is at relatively moderate levels and when it is at extreme levels. We considered that the efficiency and consumer outcomes arguments in this chapter apply in all of these circumstances, that is, for both normal and extreme negative IRSR, regardless of whether net IRSR is positive or negative. Creating different rules for different circumstances would introduce unnecessary complexity and potential for unpredictable outcomes.

Allocation by regional demand would provide stable outcomes in the longer term because regional demand is relatively stable. While energy consumption does change with time, this change happens slowly and is largely correlated between the three regions. The draft rule would use demand as defined over a 52-week rolling period. This definition would smooth out seasonal variations in demand between regions, and any shorter-term variations. To the extent that the ratio of energy consumption between the regions does change, it is appropriate that the allocation of negative IRSR should shift to reflect the change in the underlying use of the system. Some of the alternative allocation metrics we considered (SRA proceeds, TNSP revenue) would likely be less stable over time than regional demand.

Finally, dividing all negative IRSR in the same simple ratio means the draft rule would be relatively straightforward for AEMO to implement and for TNSPs to use in forecasts and pricing, thus minimising implementation costs. The choice of a rolling 52-week window to define regional demand may appear complex since the calculation must be performed weekly. However, we understand it would be feasible for AEMO to implement and of similar complexity to AEMO's other weekly settlements calculations. After the required system updates are completed, the calculation would run essentially automatically and would be simpler to manage than a less frequent ad-hoc calculation. See section 3.2.1 for the draft rule's detailed definition of regional demand.

Maintaining SRA arrangements provides stability and consistency for the market and consumers

Our draft decision not to make any changes to SRA arrangements or positive IRSR allocation aligns with good regulatory practice by promoting stability and consistency. Making a change to SRA arrangements in this rule change - which would not allow sufficient time to thoroughly consult on the options - would be disruptive to market participants who use SRD units as a key hedging instrument (section 3.3.1). This could impact consumers in turn if higher portfolio costs flowed through to retail offers, or if it influenced retailers' decisions to operate in certain regions. Given the Commission's intention to review the SRA framework in the future (chapter 4), there would also be a chance of SRA arrangements being changed twice in a relatively short time.

Further, the scope of this rule change is limited to the NSW-SA-VIC transmission loop (or to any other transmission loops that may be created in the NEM in future). If SRA arrangements were changed for transmission loops, this would create inconsistency with other NEM interconnectors.

Increased prescription with regard to clamping is not necessary

As noted above, the Commission considered whether there was a need to reduce extreme negative IRSR by clamping even when the net IRSR for the loop is positive. This would have entailed placing a new obligation on AEMO to apply clamping constraints in net positive cases, with the NER specifying a threshold or target (significantly higher than the current $100,000 clamping threshold). AEMO would have needed to add a procedure for net positive cases to the existing procedure.

Apart from the drawbacks and risks of clamping mentioned in section 2.3.3, this would be more prescriptive than the current NER approach to clamping. This would create an additional implementation burden for AEMO and such requirements in the NER may lack flexibility for AEMO to adapt to changing circumstances, particularly given the difficulty of modelling the behaviour of the loop ahead of time.

See section 3.2.5 for a more detailed analysis.

3 How our draft rule would operate

Box 1: Key points

Our draft rule would allocate negative IRSR that arises in transmission loops to all looped regions in proportion to regional demand. We consider this allocation method would be the best way to manage the risks of extreme negative IRSR, which can be significant, for consumers and TNSPs. Sharing negative IRSR by regional demand would also reflect the fact that consumers in all looped regions benefit from the efficient operation of the loop.

The Commission supports AEMO's proposed approach to clamping for the transmission loop, which is to clamp only when net IRSR for the loop is negative. We considered the merits of imposing an additional clamping requirement to limit extreme negative IRSR in net positive cases but determined that the risks outweighed the benefits as explained in section 3.2.5. The draft rule would retain the existing NER provisions around clamping (negative residue management).

The draft rule does not make changes to SRA arrangements or the allocation of positive IRSR. Changes to SRA arrangements would be complex and impact many stakeholders, and we consider that making such changes in this rule change could risk delays to PEC's market integration. The Commission has noted some potential issues with the application of the existing SRA framework to transmission loops, which are further discussed in chapter 4. However, these issues should be addressed through a separate process and we have committed to reviewing this framework in the future.

The draft rule would commence on 3 July 2025. However, it would have no practical effect until the NSW-SA-VIC transmission loop is incorporated into the NEM Dispatch Engine (NEMDE).

The Commission notes that market bodies already publish IRSR data and market analysis regularly, which will enable transmission loop outcomes to be monitored once it is operational. The draft rule would adjust AEMO's existing obligations to include publishing IRSR data for transmission loops.

In this chapter:

- Section 3.1 provides an overview of the draft rule, including the definition of transmission loops to be used in the NER.
- Section 3.2 sets out the new method for allocating negative IRSR in transmission loops and our rationale.
- Section 3.3 explains our draft decision not to make any changes to positive IRSR allocation or the SRA framework.
- Section 3.4 explains how the draft rule would be implemented.
- Section 3.5 outlines how existing AEMO reporting and Australian Energy Regulator (AER) monitoring powers can help provide transparency on whether the new allocation arrangements are performing as intended.

3.1 The draft rule would create a new allocation method for negative IRSR in transmission loops

To address the issue of IRSR management in transmission loops, the draft rule would:

- define a 'transmission loop' (section 3.1.1),
- allocate negative IRSR that accrues on interconnectors in transmission loops to all looped regions in proportion to regional demand (electrical energy consumption) (section 3.2), and
- retain the existing allocation of positive IRSR and SRA arrangements (section 3.3).

The arrangements in the draft rule are based on the assumption that AEMO will implement the clamping approach described in its rule change request (section 3.1.3). The Commission agrees with this approach and understands that AEMO will implement it without the need for a rule change.

3.1.1 A transmission loop would be defined to occur where three regions are all linked by regulated interconnectors

To implement the draft rule, it was necessary to create a definition of a transmission loop in the NER. The draft rule specifies that a *parallel interconnector configuration* occurs when three NEM regions are interconnected and there are *directional interconnectors* between each pair of regions.[34] There is a *directional interconnector* for each direction of flow on *regulated interconnectors* between adjacent regions, as explained in Box 2.[35] In other words, a *parallel interconnector configuration* is a closed loop of regulated interconnectors between three regions.

Box 2: Positive and negative IRSR accrues on directional interconnectors

Where there is a single regulated interconnector between two adjacent regions, it is conceptually broken down into two directional interconnectors, with one flowing in each direction. Directional interconnectors are labelled according to the direction of flow. For example, the VIC-NSW directional interconnector carries flows from Victoria into New South Wales and the NSW-VIC directional interconnector carries flows in the opposite direction. Both correspond to the same physical regulated interconnector, VNI.

Where there are two (or more) regulated interconnectors between two regions, they are conceptually considered to be one link which consists of two directional interconnectors.

It is important to note that IRSR is allocated to a directional interconnector before the allocation method for either positive or negative IRSR is applied. This is the case under both the current rules and the draft rule, for both looped and radial interconnectors. Where there are two or more regulated interconnectors between the same two regions, AEMO nets off the IRSR accruing on those interconnectors, in each dispatch interval, to determine the IRSR on the relevant directional interconnector. This quantity may be positive or negative. In this draft determination, when we refer to positive and negative IRSR, we are referring to the IRSR on the relevant directional interconnector.

AEMO's Methodology for the allocation and distribution of settlements residue sets out in detail how AEMO calculates IRSR for each directional interconnector.

Note: See also: AEMO, Methodology for the allocation and distribution of settlements residue, v3, 2 June 2024, aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/settlements-residue-auction-rules.

34 Draft clause 3.18.1A(a).

35 NER clause 3.18.1(c).

In this draft determination, we refer to *parallel interconnector configurations* as 'transmission loops' for simplicity.

Note that, under the draft rule's definition of transmission loops:

- The NSW-SA-VIC loop would be a transmission loop (incorporating the PEC, VNI, Heywood and Murraylink interconnectors).
- There would not immediately be any other transmission loops in the NEM.
- Since a transmission loop must include three regions, two or more regulated interconnectors that connect the same two regions (such as QNI and Directlink (Terranora) between Queensland and New South Wales) do not in themselves form a transmission loop, although they may form part of one.
  - If two or more regulated interconnectors between the same two regions form part of a loop, which will be the case for Heywood and Murraylink, the resulting directional interconnectors would be treated as one 'arm' of the loop.
- Transmission loops must be formed by regulated interconnectors, that is, merchant interconnectors (those providing market network services) and interconnectors that are not regulated interconnectors cannot form part of a transmission loop. (The draft rule would also update the definition of regulated interconnector. See section 3.1.2 and the proposed amendments to the NER Glossary definition of 'regulated interconnector'.)

This definition of transmission loops would capture other three-region loops, in addition to the NSW-SA-VIC loop. However, it is unlikely that other such loops will be built in future unless there are changes to the current NEM region boundaries.

The definition does not capture loops that involve more than three regions. Loop configurations with four (or more) regions rapidly become more complex and our analysis for this rule change has not considered these larger loops. Excluding larger loops is low-risk because there are no current infrastructure plans that would form such a loop in the NEM.

If a four-region loop did occur, the allocation of IRSR for that loop would need to be considered in a separate process.

3.1.2 The draft rule would commence in 2025 and take effect when the transmission loop is formed

The draft rule would commence on 3 July 2025, but would have no practical effect until PEC is incorporated into NEMDE, thus forming the transmission loop.

The draft rule would update the NER definition of regulated interconnector to ensure that it applies to PEC.[36] As noted above, the draft rule's definition of a transmission loop requires that the loop be formed from directional interconnectors, in turn created from regulated interconnectors. Under the draft rule, PEC would be considered a regulated interconnector when (amongst other threshold requirements) AEMO has incorporated the power flows on PEC between New South Wales and South Australia in NEMDE.[37]

The draft rule would begin to be used for the allocation of negative IRSR (except negative IRSR arising from inter-network tests) after a partial release of PEC's capacity. The testing and commissioning plan for PEC involves gradually releasing capacity over approximately 15 months from mid-2026 until the full capacity of 800 MW is released, which is expected to be in Q4 2027.[38]

36 Draft rule, Glossary definition of 'regulated interconnector'.

37 NEMDE is not a term used in the NER so the draft rule refers to incorporation of the power flows on the interconnector in the dispatch algorithm.

38 Project EnergyConnect, Project EnergyConnect System Integration industry update, 18 April 2024, https://www.projectenergyconnect.com.au/moreInformation.php, ('PEC system integration industry update').

AEMO intends to incorporate PEC into NEMDE as part of a transmission loop when a suitable level of partial capacity is released. From that time, the PEC regulated interconnector and the transmission loop would exist according to the NER definitions. For the avoidance of doubt, negative IRSR accruing on the existing VNI, Heywood and Murraylink interconnectors would continue to be allocated to the relevant importing regions until the transmission loop is incorporated into NEMDE.

AEMO expects to incorporate the transmission loop into NEMDE in Q4 2026 based on current testing and commissioning timelines, but this is subject to change. After that time, PEC capacity would continue to be released in stages. The draft rule would apply when allocating negative IRSR for the released capacity. For capacity that has not yet been released, which may still be undergoing testing, the current NER provisions for recovery of negative IRSR arising from inter-network tests would continue to apply.[39] See section 3.4.1 for more information.

We chose the draft rule commencement date to align with the commencement of the *Providing flexibility in the allocation of interconnector costs* rule on 3 July 2025. This is because our draft rule would rely on changes to the definitions of 'regulated interconnector' and 'Co-ordinating Network Service Provider' (CNSP) that are being made in the interconnector costs rule.

Note that under the draft rule, AEMO would initially recover negative IRSR from CNSPs, which is consistent with the current arrangements.[40] CNSPs pass through negative IRSR directly to customers in their regions through transmission charges.[41] In this draft determination, outside of chapter 3, we use the term TNSPs to refer to the entities responsible for negative IRSR under the draft rule, that is, Transgrid, ElectraNet, and AEMO Victorian Planning. See section 3.4.1 for more information.

3.1.3 The draft rule assumes that AEMO takes its proposed approach to clamping

AEMO has proposed a new approach to clamping that would better account for the more frequent negative IRSR that is expected in the transmission loop. Appendix C.4 provides background on the existing clamping arrangements.

Negative IRSR is expected to occur more often in the transmission loop, in a way that supports overall efficient outcomes, due to the spring washer effect (see appendix C.3). Therefore, applying the current clamping procedure would result in very frequent clamping. However, the power flows on each arm are not independent and cannot be clamped independently. If a clamping constraint is applied to one arm, it would likely impact the flows on the other arms as well, due to Kirchhoff's Law.[42] This would lead to practical difficulties with clamping in the loop, and prevent the full benefits of the loop from flowing through to consumers.

39 Draft rule clauses 3.6.5(b)(2) and (3) and clauses 5.7.7(aa) and (ab).

40 Draft rule clause 3.18.1A(c).
Currently the NER refers to the 'appropriate Transmission Network Service Provider' in clause 3.6.5(a)(3) and then defines the term within the clause. However this can now be replaced with a reference to the CNSP due to changes to the definition of 'Co-ordinating Network Service Provider' being made in the interconnector costs rule.

41 NER, Chapter 6A, Part J, in particular clauses 6A.23.3(b) and (e).

42 AEMO, PEC Market Integration directions paper, November 2023, p. 30, https://aemo.com.au/en/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper ('PEC Market Integration directions paper').

For these reasons, AEMO developed an alternative approach to clamping as part of its PEC Market Integration work. It also outlined this approach in its rule change request. The proposed approach is as follows:

- When the net residue for the loop is positive, none of the arms of the loop would be clamped (regardless of negative IRSR on individual arms).
- When the net residue for the loop is negative, the interconnectors in the loop would be clamped as per the existing procedure.[43]
- Interconnectors outside the loop would continue to be clamped as per the existing procedure.

This approach would enable better utilisation of the transmission loop, compared to the existing procedure, and would still prevent excessive negative IRSR from accumulating in cases of net negative residue. Stakeholders generally supported the proposed approach to clamping.[44] The Commission also supports AEMO's approach and we understand AEMO intends to implement it after the final rule is made, by making the necessary procedure changes.

Note that clamping constraints (in both the existing and new approaches) are intended to address the financial or economic problem of excessive negative IRSR. In this respect, they are different from most NEMDE constraints which are needed to keep the power system operating securely and within engineering limits. System security and adequacy of supply are always prioritised over clamping. AEMO achieves this by assigning clamping constraints a low constraint violation penalty (CVP), while system security constraints have a higher CVP.[45]

3.1.4 We have not considered price scaling in this rule change

Price scaling is a mechanism in the NER that adjusts the effective market price cap (MPC) in regions adjacent to a region experiencing MPC conditions, in order to avoid negative IRSR.[46] In its submission to the consultation paper, AEMO raised a potential technical problem with the application of these rules to transmission loops, noting price scaling may not be feasible when there are circular flows.[47] The Commission considers that any issues with price scaling are not directly related to the problem identified in this rule change and that addressing such issues would risk the timely completion of the rule change. The application of price scaling to transmission loops should be addressed through a separate process if required.

43 AEMO has indicated that the existing procedure would apply in principle when the net residue is negative. AEMO will consider and consult on the detailed application of this procedure to the loop interconnectors after the final rule is made.

44 Submissions to the consultation paper: AEC, p. 1; Alinta Energy, p. 2; AGL, p. 1; ENA, p. 3.

45 AEMO, Schedule of constraint violation penalty factors, v6.0, 30 June 2024, p. 31, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

46 NER 3.9.5(c). There are also equivalent clauses for the market floor price (NER 3.9.6A(c)) and APC (NER 3.14.2(e)).

47 AEMO submission to the consultation paper, p. 2.
AEMO's submission flagged a possible additional submission with more detail on the price scaling issue. Ultimately AEMO did not make an additional submission.

3.2 The draft rule would share negative IRSR between all looped regions in proportion to regional demand

Under the draft rule, all negative IRSR that accrues on an interconnector in a transmission loop would be shared amongst the three regions in the loop, in proportion to each region's electricity demand. This would apply regardless of whether net loop IRSR is positive or negative.

In this section:

- Section 3.2.1 explains how the draft rule would define regional demand and why we chose this definition.
- Section 3.2.2 outlines the problem the draft rule seeks to address - that is, risk of high negative IRSR.
- Section 3.2.3 outlines the options we considered for the draft rule and stakeholder feedback on those options.
- Section 3.2.4 explains why our draft decision is to allocate negative IRSR by regional demand.
- Section 3.2.5 outlines our consideration of an additional clamping requirement, which we decided not to include.

3.2.1 Regional demand would be defined as rolling annual energy consumption

Under the draft rule, each region would be allocated a proportion of negative IRSR equal to its proportional electricity demand. A region's proportional electricity demand would be calculated as:[48]

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

where:

Annual regional demand means *the total electrical energy consumed by a region in a year.* This would be calculated as ACE (adjusted consumed energy) for the region for the past 52 weeks on a rolling basis.[49] That is, for each billing period (week), regional demand would 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 as now in the NER.[50] 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.[51]

Total regional demand means the sum of all annual regional demand for looped regions.

Therefore, if negative IRSR arises on an interconnector within the loop in a particular trading interval, the CNSP for each region would be allocated a portion of that negative IRSR as follows:

48 Draft rule, clause 3.18.1A(a), definition of 'regional share'.

49 Draft rule, clause 3.18.1A(a), definition of 'rolling annual regional demand'.

50 NER clause 3.15.4(b).

51 Any energy exported from the connection point (i.e. generation) is not netted off from ACE but is counted in a separate quantity. ACE for a market connection point in the distribution network includes adjustments for unaccounted for energy (UFE) and distribution losses. UFE is the difference between the energy that leaves the transmission network and metered consumption, after accounting for distribution losses. It is generally related to meter faults and electricity theft. The NER provides a methodology for distributing UFE amongst market connection points for settlements purposes (NER clause 3.15.5).

> Allocation of negative IRSR for that trading interval to a CNSP = (negative IRSR on the interconnector) x (the CNSP's relevant ARD/TRD)

The calculation is applied to each directional interconnector separately. However, the result is the same as if all negative IRSR in the loop were aggregated during the trading interval and then allocated proportionally. Unlike the current arrangements, it does not matter which region(s) are importing from each interconnector.

For example, suppose that in a trading interval in November 2028, $100 of negative IRSR arises on one of the arms of the loop. Suppose that the ratio of ACE in each region, summed over the previous year, was 50% New South Wales, 30% Victoria and 20% South Australia. Then, $50 in negative IRSR would be allocated to the CNSP for New South Wales, $30 to the CNSP for Victoria, and $20 to the CNSP for South Australia.

We considered various factors in coming to this draft definition of regional demand

We consider ACE is a suitable quantity for calculating regional demand that adequately reflects customers' underlying consumption. We considered as an alternative the quantity ME- (metered consumed energy), which is equivalent to ACE before adjustments for distribution losses and unaccounted for energy. However, since those adjustments are small and do not differ significantly between regions, we consider there is likely to be little difference in the actual IRSR allocations based on ME- or ACE.

Further, we understand it is simplest to use ACE from an implementation perspective because many settlement equations already use ACE.[52] The ACE quantity is readily available in AEMO's settlement systems, whereas ME- is not, because the adjustment for distribution losses is executed within AEMO's metering systems.

We considered the merits of excluding ACE for scheduled bidirectional units from the calculation of regional demand. Consumption by bidirectional units could be considered to be double-counted since (most of) the energy they draw from the grid is later released and used by a customer. However, our view is that consumption by bidirectional units still reflects an underlying use of the network. Also, excluding bidirectional units would introduce complexities, for example where some types of storage are not classified as scheduled bidirectional units under the NER, and where storage and loads may share the same connection point. For these reasons we decided to include bidirectional units along with all other market connection points in our definition of regional demand.

We considered various timeframes for determining proportional regional demand, including longer (multiple years) or shorter (seasons or weeks) timeframes, and fixed as opposed to rolling timeframes. We preferred a timeframe of a full year because we consider this would provide sufficiently stable and predictable outcomes. The use of a rolling timeframe would ensure that the allocation is based on the most recent consumption data and best reflects consumers' usage of the system. We also understand it would be feasible for AEMO to calculate annual regional demand on a rolling basis each week by integrating it into its settlement systems which operate weekly.

52 For example: the recovery of costs for raise frequency control ancillary service, network support and control ancillary services, and compensation under administered price cap or administered floor price.

3.2.2 We decided on a regional demand allocation method to address the risk to consumers of extreme negative IRSR

Our consultation paper analysis suggested there may not be a clear problem with applying the current allocation arrangements in a transmission loop

Our consultation paper set out the issue that a transmission loop may accrue large and unpredictable amounts of negative IRSR. This is a result of the normal operation of loop flows, where flows on one 'arm' (interconnector) will affect flows on the other arms, which in turn affects prices in all three regions. This outcome is associated with a pricing phenomenon called the 'spring washer effect', where a constraint in a transmission loop leads to a large price separation across the constraint and increasing prices around the loop (appendix C.3). We also expect that AEMO would not clamp individual arms of the loop when net IRSR is positive (section 3.1.3).

AEMO's rule change request proposed a new method of allocating negative IRSR in a transmission loop (appendix A). The proposed rule sought to manage frequent negative IRSR more effectively, given that the loop interconnectors would not be subject to clamping for a large fraction of the time. AEMO's proposed rule would allocate negative IRSR arising on one or more directional interconnectors of the loop to directional interconnectors that are accruing positive residues. AEMO considers that this approach would best align costs with beneficiaries of the loop flow.

Our consultation paper provided analysis looking at IRSR allocation and wholesale price outcomes in a transmission loop. We concluded that allocating negative IRSR to importing regions (the status quo) would generally allocate benefits (SRA proceeds) to regions where the wholesale price is higher, while allocating costs (negative IRSR) to regions where the wholesale price is lower. By contrast, AEMO's proposed rule would allocate benefits (SRA proceeds) in the same way – where the price is higher – but would also recover costs from higher-priced regions. This appeared to be a drawback of AEMO's proposed reallocation method.

We conducted further analysis showing that periods of extreme negative IRSR are plausible

In feedback to our consultation paper, stakeholders considered that it is not relevant to consider wholesale price outcomes (see section 3.2.4), but emphasised the potential for cash flow impacts on CNSPs (see below).

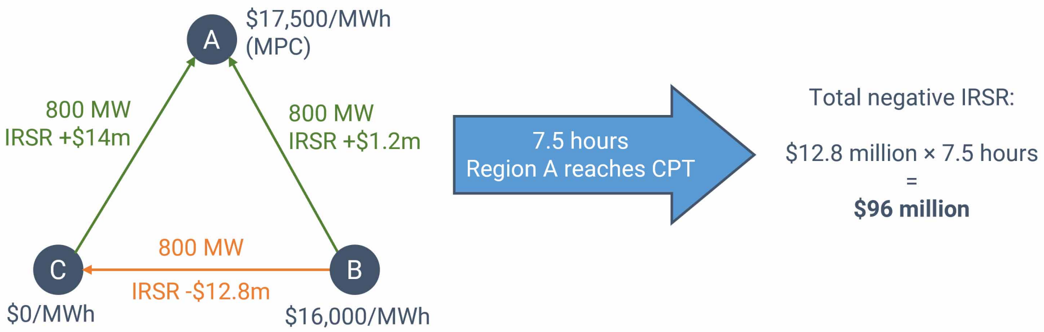
To investigate this issue, we conducted further analysis on the amount of negative IRSR that could plausibly accrue in net positive cases (when AEMO proposes not to clamp negative residues). This amount could be very large - being limited only by the MPC and administered pricing regime. While it is difficult to predict the average negative IRSR or the maximum that is likely to accrue, we have constructed a theoretical scenario to illustrate that extremely large quantities of negative IRSR are possible - potentially up to $100 million in a single week, as shown in Figure 3.1 and Box 3.

The scenario in Box 3 is contrived, and may be unlikely to occur in reality, but it is plausible. While we do not rely on it to represent actual outcomes, it is informative for our analysis and supports our thinking. The likelihood of the scenario is low because it relies on near-MPC conditions in two (but not three) looped regions, a specific instance of the spring washer effect, and large flows on at least two arms of the loop. Also, the greatest negative IRSR only occurs when these conditions persist long enough to trigger the administered pricing regime. That said, negative IRSR need not reach the full extent of this example to negatively impact consumers, and it may be possible (although, again, not likely) for multiple extreme negative IRSR events to occur within a year.

Box 3: Transmission loops may accrue large and unpredictable amounts of negative IRSR

Figure 3.1, below shows a possible scenario in which a transmission loop accrues large amounts of negative IRSR. IRSR is shown per hour (instead of per dispatch interval) for simplicity. If the conditions in Figure 3.1 were sustained for 7.5 hours as permitted by the cumulative price threshold (CPT), the total negative IRSR accrued would be close to $100 million.

Figure 3.1: Negative IRSR of up to $100 million may accrue in sustained extreme market conditions



In this extreme scenario, region A is at the MPC, region B is close to the MPC, and region C has a price of zero. The B-C interconnector accrues $12.8 million in negative IRSR per hour. The C-A interconnector accrues an even greater amount of positive IRSR ($14 million per hour), so the loop IRSR is net positive and none of the flows are clamped. This scenario could continue for 7.5 hours (consecutively or in a seven-day period) before the CPT is reached, triggering administered pricing in region A. By this point, the total negative IRSR accrued would be close to $100 million. This represents a significant cost and risk for consumers.

When region A goes into administered pricing, market dynamics may change such that negative IRSR stops accruing so quickly. If not, then administered pricing would also be triggered in region B shortly afterwards, stopping most of the negative IRSR.

Note: This is a simplified theoretical example designed to indicate the largest amount of negative IRSR that may be possible in the NSW-SA-VIC transmission loop. We have not performed a mathematical optimisation to prove that this is the absolute maximum. We used the 2024-25 values of the MPC and CPT, noting both are set to progressively increase between 2025 and 2027, in addition to the annual adjustment for CPI (AEMC, Schedule of reliability settings 2024-25, Feb 2024). The price in region B is set lower than the MPC to approximately represent price scaling. Interconnector flows are based on the capacities of the real interconnectors but are approximate. Future interconnectors or transmission upgrades would likely increase the potential for negative (and positive) IRSR. The flows shown are consistent with the spring washer effect where a constraint is binding on the C-A interconnector, but this is not necessarily the only way for this pattern of flows to manifest. The flows and prices do not account for AEMO's transmission loop constraint, which has not yet been determined.

Some stakeholders considered that additional modelling would be needed to evaluate the options for IRSR allocation in a transmission loop, for example to quantify the impacts of negative IRSR on CNSPs and end customers.[53] AEMO commissioned ACIL Allen to model IRSR in the transmission loop as part of its PEC Market Integration work.[54] However, this modelling was designed to produce plausible outcomes against which to test reallocation methods, and was not intended to produce accurate market forecasting of actual IRSR levels or price results.[55]

While the Commission appreciates the value of a robust estimate of the magnitude of negative IRSR and how much it could vary, we have not undertaken further modelling in this rule change. This is due to the fact that we do not consider that market modelling would provide us with

53 Submissions to the consultation paper: ENA, p. 2; Alinta Energy, p. 1; EnergyAustralia, p. 2; Engie, p. 2.

54 ACIL Allen, 'Modelling the settlement effects of PEC'.

55 AEMO, PEC Market Integration directions paper, p. 21.

valuable new information, beyond what AEMO has demonstrated. Modelling the extent of negative IRSR would be complex because IRSR is sensitive to a wide range of factors, including spot prices, demand patterns, network constraints, and participant bidding behaviour. The loop may also influence investment and operational decisions. These factors are difficult to forecast, and so modelling results may turn out to be inaccurate. In addition, this rule change needs to be completed by March 2025 to allow sufficient implementation time before PEC becomes operational.

This extreme negative IRSR needs to be managed because it poses risks to CNSP cash flows and consumer retail bills

The potential for extreme negative IRSR presents a risk to consumers' retail bills if it was to arise, because CNSPs recover negative IRSR from consumers through transmission charges.

If most or all of the negative IRSR resulting from a given event was allocated to a single region, it could have a noticeable effect on retail bills for consumers in that region. For example, South Australia has about 900,000 electricity customers. Therefore, our extreme example of $100 million in negative IRSR, from Figure 3.1, would add more than $100 to the average customer's retail bill over a year. The Commission considers this risk to consumers is significant.

The possibility of concentrated IRSR allocation was raised by EnergyAustralia in its submission, which suggested that the Commission "explore the risk of whether the proposed arrangements allow for very large or persistent negative residue allocations to particular TNSPs, even when within a 'net positive' situation around the loop."[56]

Negative IRSR may also differ significantly from one year to the next (even if no single event is as extreme as Figure 3.1). This would translate to volatile or 'lumpy' consumer bills where the component relating to transmission charges is significantly higher or lower in one year than it was in the previous year. Note that negative IRSR is not spread over multiple years from the customer's perspective, but is generally recovered within one or two years of its accrual, depending on true-up (see Box 4). ENA raised this issue in its submission, noting that:[57]

> The scale and timing of negative settlements residue that could potentially arise from the AEMO rule change and alternative options will have a significant impact on transmission price stability.

Relatedly, extreme negative IRSR also presents a cash flow risk to CNSPs.

Negative IRSR is initially recovered from CNSPs. The timing for CNSPs to pay negative IRSR is different to the timing with which they recover it from consumers. Because of this, it may be challenging for CNSPs to ensure they have the cash or liquid assets on hand to pay AEMO before the revenue is received from customers, particularly if the negative IRSR liability is large. We refer to this as 'cash flow risk'.

When setting transmission prices, CNSPs use forecasts of negative IRSR and SRA proceeds. CNSPs can generally forecast SRA proceeds accurately because around 80 per cent of the SRD units for the coming year have already been sold at auctions held during the past three years. However, negative IRSR flows directly to CNSPs, and is difficult to forecast for the same reasons that it is difficult to model. ENA's submission to the consultation paper noted the difficulty of forecasting negative IRSR and the resulting impacts on CNSPs and transmission pricing.[58]

56 EnergyAustralia submission to the consultation paper, p. 2.

57 ENA submission to the consultation paper, p. 4.

58 ENA submission to the consultation paper, p. 1.

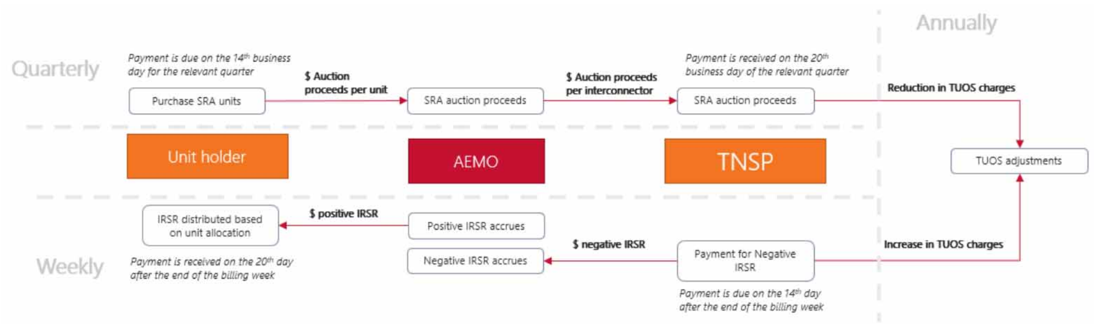
Where negative IRSR differs from CNSPs' forecasts - which appears likely - there can be up to a two-year delay between negative IRSR accrual and recovery from customers.[59] This is because prices are fixed before the start of the year, and any under-recovery (or over-recovery) can only be trued-up in the following year. In this situation the CNSP would need to borrow the under-recovered amount for up to two years and recover the cost of debt from consumers at the regulated WACC, set by the AER.[60] Box 4 outlines the current timing for the recovery of negative IRSR from (and the return of SRA proceeds to) CNSPs and consumers.

Box 4: CNSPs pass through negative IRSR and SRA proceeds via transmission charges

Figure 3.2 shows how positive and negative IRSR and SRA proceeds are transferred between AEMO, SRD unit holders, CNSPs, and consumers. In particular, from a CNSP's perspective:

- CNSPs set transmission prices each March for the coming financial year (NER clause 6A.24.2(c)(1)). These prices take into account *forecast* negative IRSR and *forecast* SRA proceeds.
- Over the course of the year, CNSPs pay actual negative IRSR directly to AEMO on a weekly basis.
- CNSPs receive proceeds from the auction of SRD units on a quarterly basis (matching the frequency of auctions).
    - Note that auction participants purchase SRD units up to three years in advance, but only pay for those units in the relevant quarter.
- At the end of the financial year, CNSPs calculate the difference between forecast IRSR, forecast SRA proceeds, and actual revenue (known as 'true-up'). This amount, adjusted by the weighted average cost of capital (WACC), is recovered from (or returned to) consumers over the following financial year.

Figure 3.2: Timing of cash flows between AEMO, CNSPs, SRD unit holders, and consumers



Source: AEMO, PEC Market Integration directions paper, p. 11.

Source: AEMO, PEC Market Integration directions paper; ENA submission to the consultation paper.

59 Ibid., p. 4.

60 AER, 'AER releases final decision on rate of return for regulated energy networks', 24 February 2023, https://www.aer.gov.au/news/articles/communications/aer-releases-final-decision-rate-return-regulated-energy-networks.
Conversely, the CNSP would need to hold any over-recovered amount for up to two years before returning it to consumers, with interest, calculated at the WACC.

Further to this, CNSPs' weekly negative IRSR cash flows could be volatile. This could have increasingly pronounced financial impacts on CNSPs as the extent of negative IRSR increases. ENA submitted that:[61]

> [T]here is a higher risk of market-based negative residues occurring more frequently [...] in transmission loops. It is crucial that this risk be investigated and quantified by the Commission as large and frequent calls on TNSPs to fund unclamped negative residues will impact the cash flow and financeability of their business operations and impose material transmission price impacts on customers.

The Commission understands that the potential for extreme negative IRSR could have a number of consequences for CNSPs, for example:

- CNSPs may need to arrange larger debt facilities to cover the potential for large negative IRSR, even if large negative IRSR occurs rarely or never. Higher levels of debt facilities are likely to incur higher financing costs, which CNSPs cannot necessarily recover from consumers if they exceed the regulated WACC.
- Debt, interest expenses, and volatile cash flows due to IRSR could impact CNSPs' credit rating metrics and financial covenants. This could in turn impact a CNSP's ability to access debt facilities and create or increase barriers to investment in network infrastructure.[62]

These impacts could also translate to undesirable outcomes for consumers. If there are barriers to CNSPs accessing finance, this could increase the likelihood of delayed investment in network infrastructure, potentially affecting security and reliability of supply. Also, if CNSPs were permitted to recover additional costs of debt to finance negative IRSR, this would lead to higher costs for consumers.

We note that the rules for recovering negative IRSR from CNSPs were created in the context of a radial transmission system.[63] In a radial system, negative IRSR is expected to be infrequent and the magnitude can be limited by clamping. (Despite this, negative IRSR has sometimes been high in recent years.[64]) The introduction of a transmission loop is likely to significantly increase negative IRSR and exacerbate cash flow challenges that CNSPs, to some extent, are already facing.

Some submissions suggested that CNSP cash flow implications and concerns would be more appropriately addressed through other avenues such as the economic regulation framework for transmission network businesses.[65] We note that CNSP cash flow concerns are a subject in the *Improving the cost recovery arrangements for non-network options* rule change, which the Commission is currently progressing.

61 ENA submission to the consultation paper, p. 2.

62 ENA has described this as impacting the "financeability of [TNSPs'] business operations" (submission to the consultation paper, p. 2). We note that any financeability impacts resulting from exposure to negative IRSR may not be related to the financeability challenges the Commission considered in the 2024 *Accommodating financeability in the regulatory framework* rule change. For the avoidance of doubt, cash flow issues related to IRSR would not necessarily be grounds for a TNSP to submit a financeability request to the AER.

63 Submissions to the consultation paper: ENA, pp. 3-4; AEMO, p. 5.

64 AEMO, Quarterly Energy Dynamics reports, 2020-2024, https://aemo.com.au/en/energy-systems/major-publications/quarterly-energy-dynamics-qed ('QED reports').

65 Submissions to the consultation paper: AEC, p. 2; Engie, p. 2; Origin Energy, p. 4; Shell Energy, p. 4.

3.2.3 We considered a range of IRSR allocation options to assess whether they would address the risks of extreme negative IRSR

There are only three broad methods of managing the risk of extreme negative IRSR:

- **Hedge the risk of negative IRSR via the SRA framework**. As explained in section 3.3.1, we have decided not to change SRA arrangements in this rule change. However, we consider it worthwhile to review these arrangements in future, as discussed in chapter 4.
- **Share the negative IRSR by allocating it between TNSPs**. Section 3.2.4 explains how we considered options for allocation methods and concluded that sharing by regional demand achieves the best outcomes for consumers.
- **Limit the magnitude of negative IRSR** in a transmission loop (in net positive cases) by clamping or another mechanism. Section 3.2.5 explains that we consider clamping would be the best option to limit the magnitude of negative IRSR, but we concluded that imposing extra clamping limits would create worse outcomes for consumers than not doing so.

Since we have decided not to pursue solutions that **hedge** negative IRSR or **limit** its magnitude, our draft rule manages the risk by **sharing** negative IRSR between regions.

3.2.4 Sharing negative IRSR by regional demand achieves the best outcomes for consumers

This section explains why the Commission has selected the regional demand allocation option for the draft determination.

We considered a range of options for the **allocation** of negative IRSR in transmission loops. The options consisted of AEMO's proposed rule and additional options based on some of the alternatives that we raised in our consultation paper.

- **Status quo** (alternative Option 1 in our consultation paper): Allocating all negative IRSR to the importing region for the interconnector and dispatch interval in which it accrues, as per the current arrangements (appendix C.2).
- **AEMO's proposal:** When net loop IRSR is positive in a dispatch interval, reallocating negative IRSR to the importing region(s) for the interconnector(s) that accrue positive IRSR in that dispatch interval, in proportion to the amount of positive IRSR accrued. When net loop IRSR is negative in a dispatch interval, allocating negative IRSR to the importing region as per status quo (appendix A.1).
- **Regional demand** (from alternative Option 2c): Allocating all negative IRSR amongst all three looped regions in proportion to regional demand (section 3.2).
- **Variant options:**
  - A variation of AEMO's proposal, where negative IRSR is reallocated in proportion to SRA proceeds instead of in proportion to positive IRSR (similar to alternative Option 2b, but not considered in the consultation paper).
  - Alternative methods for sharing negative IRSR amongst all three looped regions, for example in proportion to customer numbers or CNSP revenue (variations of alternative Option 2c).

We excluded the consultation paper's Option 3, which would have involved changes to SRAs, for the reasons discussed in section 3.3.1. We also excluded Option 2a (reallocating both positive and negative IRSR) because it would similarly impact SRD unit payouts and firmness.

Among the options presented in the consultation paper, a majority of stakeholders preferred AEMO's proposed rule.[66] Shell Energy preferred the status quo arrangements and Snowy Hydro was open to either AEMO's proposal or the status quo.[67] JEC did not prefer any particular option.[68]

The Commission has assessed the options based on three key considerations, which sometimes overlap:

- mitigating or distributing the risks of unpredictable IRSR,
- allocating costs in a way that reasonably reflects the benefits,
- allowing the transmission loop to operate in a way that maximises the consumer benefits of PEC and the other interconnectors.

These considerations align with our assessment criteria for the rule change - in particular, the 'principles of market efficiency' and 'outcomes for consumers' criteria.

We consider that the regional demand approach, alongside the existing SRA framework and AEMO's proposed approach to clamping in the loop, best balances these considerations, as outlined below.

Allocation by regional demand best manages the risk of extreme negative IRSR

Allocating negative IRSR by regional demand would mean that any risk of extreme negative IRSR in the loop would always be shared between all CNSPs and therefore all consumers in the loop. Using regional demand as the allocation metric spreads the risk according to consumer usage of electricity. This aligns CNSPs' shares of negative IRSR with the customer base they serve (approximated through consumption). CNSPs in smaller regions (that is, with fewer consumers or consumers who use less electricity) would pay a smaller share of negative IRSR.

Allocating by regional demand could also reduce the volatility of negative IRSR payments. Annual regional demand (consumption) is a stable sharing metric that does not change significantly year-on-year. This means CNSPs would face a relatively stable negative IRSR cash flow, and it would form a relatively stable component of consumers' bills, subject to the variation in actual total negative IRSR. Some other reallocation methods we considered, such as allocating in proportion to quarterly SRA proceeds, could result in variable shares for each and compound the volatility of outcomes.

Other allocation methods would not share the risk as widely. Under the status quo allocation, it is likely that an instance of extreme negative IRSR could be entirely recovered from one region. For example, in Figure 3.1, all negative IRSR would be allocated to region C, which is the importing region for the counter-price flow. Under AEMO's proposal, an instance of extreme negative IRSR when net loop IRSR is positive would be recovered from one or two regions. In Figure 3.1, the negative IRSR would be entirely recovered from region A because it is the importing region for both arms accruing positive IRSR. The Commission considers it is not in consumers' interest to create a risk of extreme negative IRSR being recovered from consumers in a single region.

Allocation by regional demand would produce reasonably cost-reflective outcomes

A 'cost reflective' negative IRSR allocation method would seek to recover negative IRSR from those customers who have derived benefits from the loop in a particular instance, or from all customers to the extent that each has benefited.

66 Submissions to the consultation paper: AFMA, p. 1; EnergyAustralia, p. 1; Engie, p. 2; AEC, p. 2; AEMO, p. 3; Alinta Energy, pp. 1-2; ENA, p. 3; AGL, pp. 2-3; Origin Energy, p. 3.

67 Submissions to the consultation paper: Shell Energy, p. 1; Snowy Hydro, p. 1.

68 JEC submission to the consultation paper, p. 1.

We consider that allocating the costs of negative IRSR by regional demand reflects how consumers benefit from the operation of the loop. In the long term, the loop will have benefits for all consumers in the looped regions, including inter-regional trade, lower emissions, and improved security and reliability. If negative IRSR is allocated in proportion to regional demand, each region's costs would approximately align with its underlying use of the system and hence the benefits derived from the loop.

This is a different, and broader, way to view costs and beneficiaries than both the rule change proposal and the 'status quo' alternative we analysed in our consultation paper. We have favoured this broader view following further analysis, as well as stakeholder feedback about considering consumer outcomes more holistically.[69]

AEMO's proposed rule seeks to align costs with beneficiaries, where positive IRSR is the 'benefit'. Negative IRSR would be reallocated to arms of the loop accruing positive IRSR in the same dispatch interval (when net loop IRSR is positive).[70] However, consumers are not directly exposed to positive IRSR. Consumers receive SRA proceeds, rather than actual positive IRSR, and the two are not necessarily equivalent, even in the long term (see section 4.3).

AEMO considered that expectations of positive IRSR would influence SRD unit prices and auction proceeds, and this is true to an extent.[71] However, we consider AEMO's proposal would only work as intended if market outcomes (positive and negative IRSR) align with expectations (reflected in SRA proceeds). Extreme negative IRSR, by definition, would typically not be aligned with market expectations. This means that recovering extreme negative IRSR from a single region (or two regions) under AEMO's proposal would not only be a significant risk for consumers as outlined above, but it would not directly correspond to a benefit derived from the loop.

In our consultation paper, we set out that allocation to the importing region (status quo) would align negative IRSR with wholesale price outcomes. We considered that flows on the loop would influence wholesale prices and consumers in the importing region for a counter-price flow would benefit from the associated low prices.[72]

However, the status quo allocation only performs well to the extent that wholesale prices align with market expectations. As AEMO and several other stakeholders noted, consumers are not directly exposed to wholesale prices.[73] Origin Energy, for example, argued that:[74]

> The wholesale component of retail prices is determined using a risk-adjusted hedged book which is typically built over several years in order to minimise exposure to high spot prices. This means that pricing impacts on end consumers may not easily be observed through pool prices only.

Consumers' retail prices depend on contract prices, which in turn depend on market expectations of wholesale prices. Wholesale prices also drive IRSR. Market expectations would not account for large wholesale price separations that lead to extreme negative IRSR, which is not likely to occur

69 Submissions to the consultation paper: AEC, p. 2; Origin Energy, p. 3; Engie, p. 3; AEMO, p. 6.

70 AEMO rule change request.

71 Ibid., p. 10.

72 AEMC, IRSR arrangements for transmission loops, consultation paper, pp. 20-21.
The Commission notes AEMO's counter-argument that the transmission loop should reduce, rather than exaggerate, the difference between the highest and lowest priced regions in the loop (AEMO's submission to the consultation paper, p. 9). We maintain that the spring washer effect could sometimes exaggerate high and low prices, but acknowledge that the full impact of the transmission loop on spot prices would likely be more complex. For this reason and the reasons discussed in the main text, we have not placed a high weight on aligning negative IRSR with wholesale price outcomes in our draft decision.

73 Submissions to the consultation paper: AEC, p. 2; Origin Energy, p. 3; AEMO, p. 6; Engie, p. 3.

74 Origin Energy submission to the consultation paper, p. 3.

often. Therefore, the status quo allocation method could also result in a single region incurring a large cost without a corresponding benefit.

In summary, allocation by regional demand does not attempt to account for wholesale price impacts (as per the 'status quo' approach), positive IRSR (as per AEMO's proposed approach), or other loop impacts at a specific point in time. SRA proceeds and influences on wholesale prices are two paths by which benefits may flow to consumers, but the loop also has broader long-term benefits, which are better reflected in the regional demand method compared to other options.

3.2.5 We considered additional clamping to limit extreme negative IRSR, but determined this would create worse outcomes for consumers

Allocating negative IRSR according to regional demand would share the risk of extreme negative IRSR as widely as possible. However, it is possible that very large, negative IRSR, even if shared widely, may still be detrimental to consumers.

As a result, the Commission considered whether there was merit in limiting the magnitude of negative IRSR when it reached 'extremely high' levels, even in the case of net positive IRSR.

We considered three ways to do this:

- imposing administered **price caps** in one or more of the regions. This might operate like the existing administered pricing regime, with a 'cumulative IRSR threshold' analogous to the cumulative price threshold, beyond which prices in the regions are adjusted to reduce regional price differences, and in turn negative IRSR.
- **directing** market participants such as generators in such a way that the flows on the interconnectors are reduced, hence reducing IRSR. This might involve an 'extreme' threshold beyond which AEMO would begin issuing directions.
- **clamping:** requiring AEMO to limit negative IRSR by clamping when negative IRSR in the loop reaches an 'extreme' threshold, even if the net loop IRSR is positive. EnergyAustralia suggested that we consider whether this 'secondary clamping threshold' may be needed.[75] Clamping would be implemented, as now, via constraints in the dispatch process which limit flows across the loop interconnectors. (See appendix C.4 for more information about clamping, and section 3.1.3 for AEMO's proposed approach for the loop.)

Of these three options, we preferred clamping because the other two options have significant drawbacks:

- We are concerned that imposing an administered pricing regime would have far-reaching, disruptive consequences. Prices provide incentives for market participants in operational and investment timescales. Adjusting prices is likely to negatively disrupt these incentives, which would ultimately be detrimental to consumers.
- Directions would be difficult for AEMO to administer. To orchestrate a particular flow on the interconnector, AEMO may have to direct many generators, which is likely to be complex. AEMO would need to continually update these directions as flows changed elsewhere in the network.

75 EnergyAustralia submission to the consultation paper, p. 2.

On balance, however, we also identified significant issues with an additional clamping threshold:

- Clamping in net positive cases would likely increase the cost of dispatch. Clamping interconnectors reduces inter-regional trade, and therefore reduces the ability to use lower cost inter-regional generators instead of higher cost local ones. This would likely increase costs for consumers.
- Clamping may increase emissions because it prevents the lowest-cost combination of generators being used, and the lowest-cost combination is typically weighted towards low variable cost renewable generators.
- Clamping changes dispatch quantities and wholesale prices, with widespread implications across the market:
  - It would be likely to negatively impact operational, investment and contracting decisions by generators, loads, and storage.
  - Clamping on an individual interconnector impacts flows on other arms of the loop, in turn affecting positive and negative IRSR elsewhere on the loop. In turn this can impact SRD unit payouts or firmness (with flow on impacts for inter-regional trade) and SRA proceeds received by consumers.
- Clamping is practically challenging for AEMO, particularly on a loop, increasing its costs. Designing an appropriate clamping procedure would also be difficult without operational experience of PEC.

Fundamentally, clamping is an intervention in efficient dispatch to address a financial problem (negative IRSR). This intervention has both physical consequences (such as different generators being dispatched) and financial consequences (such as impacts on wholesale prices). There is, in general, a trade-off between high negative IRSR and these unintended consequences. Most of the issues identified above result from this dynamic.

Given these issues, the draft rule would not impose a requirement on AEMO to use clamping to limit the magnitude of extreme net negative IRSR.[76] The Commission considers there are risks to consumers both with an additional clamping threshold (as listed above) and without (the risk of instances of extreme negative IRSR). On balance, we consider that creating the additional clamping requirement would have greater risks and have therefore decided against it. The risks of extreme, unclamped negative IRSR could be better addressed through a more holistic review of IRSR arrangements including the SRA framework (see chapter 4).

3.3 Positive IRSR would continue to be allocated through the SRA process

The draft rule does not make any changes to how positive IRSR is allocated. Positive IRSR would continue to be allocated to SRD unit holders via the SRA process.

The Settlements Residue Auction is held quarterly by AEMO. Eligible auction participants, including market participants and traders, bid for the right to receive portions (units) of future positive IRSR. Participants may purchase SRD units relating to positive IRSR that will accrue up to three years in the future. The auctions are conducted according to the Settlements Residue Auction Rules (auction rules), which are developed and updated by AEMO with the approval of the Settlement Residue Committee.[77] See appendix C.2.2 for more information about SRAs.

76 For the avoidance of doubt, it would still be in AEMO's remit to develop and consult on a clamping procedure, for both transmission loops and radial interconnectors.

77 AEMO, Settlements Residue Auction Rules, 9 August 2024, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/settlements-residue-auction-rules ('SRA rules').

Positive IRSR, like negative IRSR, ultimately flows through to consumers. Instead of receiving positive IRSR directly, the importing CNSP receives the proceeds of the auction and passes this amount through to its customers via transmission prices.

In the lead-up to PEC commencing operation, we expect that AEMO will update the auction rules to include SRD unit categories for SA-NSW and NSW-SA. Apart from this introduction of new SRD units (which is a procedure change and not a NER change), there would be no changes to the SRA process or the allocation of positive IRSR under the draft rule.

We note that the introduction of PEC will inevitably influence spot prices in all regions and power flows on all interconnectors, in the transmission loop and to a lesser extent outside of it. This means it may positively or negatively impact the payouts of SRD units on other interconnectors. Broadly, however, SRAs are still expected to provide inter-regional hedging benefits in the same manner as they do today.

AEMO's previous analysis of the ACIL Allen modelling results suggested that SRD units in the loop should provide a similar level of hedging value as SRD units currently do.[78] Snowy Hydro commented that a more holistic analysis of hedging could help market participants understand the overall impacts of PEC.[79] We acknowledge that IRSR and SRA outcomes are likely to be difficult to predict and we have not analysed those outcomes in-depth, particularly as our draft rule would not make changes to SRAs. There may be an opportunity for further analysis in the Commission's future review of the SRA framework.

3.3.1 Positive IRSR arrangements are best considered in a broader process

The Commission considered potential changes to how positive IRSR is allocated, as well as negative IRSR allocation, as part of this rule change. While AEMO's rule change request only proposed changes to negative IRSR allocation, the current arrangements for positive IRSR in transmission loops are relevant for two reasons.

First, this rule change is dealing with dispatch outcomes where negative IRSR is being more-than-offset by positive IRSR. That is, in cases where the net loop IRSR is positive, negative IRSR arises as a by-product of overall positive IRSR, and overall energy flows from lower- to higher-priced regions. This raises the question of whether negative IRSR in such cases should be directly netted off from positive IRSR, rather than separately allocating negative IRSR to CNSPs and consumers.

Second, as outlined in section 3.2.2, the different treatment of negative and positive IRSR creates asymmetric risks for consumers and CNSPs. More consistent arrangements for positive and negative IRSR in transmission loops could reduce these risks. This is discussed further in section 4.1 and section 4.2.

However, the Commission's draft decision is not to make any changes to SRAs or positive IRSR allocation in this rule change. Instead, we intend to consider the current arrangements in a future review (section 4.4). There are two key reasons for this approach.

First, any changes to positive IRSR and SRA arrangements should be considered for the whole NEM, not just for transmission loops. If changes were only implemented in transmission loops, this would create significant inconsistency between jurisdictions, increasing complexity and potentially distorting incentives for inter-regional trade. Further analysis should therefore consider arrangements for both radial and looped systems.

78 AEMO, PEC Market Integration final report, February 2024, pp. 30-38, https://aemo.com.au/en/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper.

79 Snowy Hydro submission to the consultation paper, p. 1.

Second, changing these arrangements in this rule change would risk delays to the market integration of PEC. In its rule change proposal and consultation paper submission, AEMO noted a timely consideration of negative IRSR arrangements was needed to avoid delays in the implementation and market integration of PEC.[80] AEMO also submitted that any broader issues with IRSR or SRAs should be dealt with in other processes.[81] Changes to how positive and negative IRSR are allocated through SRAs are more complex and likely to be contentious, and have implications for a broader range of stakeholders. Addressing these considerations would take time, which means they are not practicable to address in this rule change without risking delays to the market integration of PEC.

We note that many stakeholders' submissions to the consultation paper strongly opposed any changes to the current arrangements for allocating positive IRSR through SRAs.[82] Market participants were of the view that any changes to SRAs could reduce the firmness and/or value of SRD units, and that this would negatively impact market participants and consumers as follows.

- A number of stakeholders submitted that netting off negative residues from SRA payouts, or making any other changes, would reduce the firmness of SRD units, making them less effective for inter-regional hedging.[83]
    - Origin Energy noted that the units are valuable to market participants even though they are currently not completely firm.[84] Nevertheless, submissions from retailers, generators and traders generally considered that SRD units are key inter-regional hedging instruments and that a reduction in firmness would adversely impact inter-regional hedging, trading, and liquidity.[85]
    - Some also noted that the importance of inter-regional trading may increase as the NEM transitions towards renewable energy sources.[86]
- Stakeholders also submitted that SRD units support robust competition and lower costs for consumers, because of their role in inter-regional hedging.[87] EnergyAustralia, for example, noted that the "ability to manage risk ultimately lowers cost for market participants and should flow through to customers."[88]
    - A number of stakeholders considered that the benefits to consumers of SRD units in risk management and enabling competition outweighed the costs of negative IRSR.[89] Origin Energy cited analysis by the Energy Reform Implementation Group showing that "inter-regional hedging strategies incorporating SRD units can result in lower net purchase costs compared to purely intra-regional hedging strategies."[90]
    - Some stakeholders raised concerns that changes to inter-regional hedging could create barriers to participating in the market, especially for the South Australian market and/or for

80 AEMO rule change request, p. 10; AEMO submission to the consultation paper, p. 1.
81 AEMO submission to the consultation paper, p. 4.
82 Submissions to the consultation paper: Shell Energy, Origin Energy, Snowy Hydro, AFMA, Alinta Energy, EnergyAustralia, Engie, AEC, AEMO.
83 Submissions to the consultation paper: Shell Energy, p. 2; Snowy Hydro, p. 2; AFMA, p. 2; Origin Energy, p. 1; Engie, p. 2.
84 Origin Energy submission to the consultation paper, p. 1.
85 Submissions to the consultation paper: Origin Energy, p. 1; AEC, p. 2; Engie, p. 2; Alinta Energy, p. 1; AFMA, pp. 1-2.
86 Submissions to the consultation paper: Snowy Hydro, p. 2; AFMA, p. 2; Engie, p. 2; EnergyAustralia, p. 1.
87 Submissions to the consultation paper: Shell Energy, p. 2; Origin Energy, p. 1; Snowy Hydro, p. 2; AEC, p. 2.
88 EnergyAustralia submission to the consultation paper, p. 1.
89 Submissions to the consultation paper: AFMA, p. 2; AEC, p. 2.
90 Origin Energy submission to the consultation paper, p. 2; Energy Reform Implementation Group, Review of Energy Related Financial Markets (Appendix C), https://www.environment.gov.au/system/files/energy/files/financial_market_review_kpmg20070413120316.pdf.

smaller players.[91] Such impacts could reduce competition amongst generators and in the retail market, leading to higher prices for consumers.

- Finally, Shell Energy noted that SRD unit prices could fall if the units were of less value to market participants. This would reduce some of the direct benefits to consumers, since consumers receive the proceeds of SRAs via their CNSP.[92]

3.4 Detailed operation and implementation of the draft rule

3.4.1 The draft rule would restructure the relevant clauses for clarity

IRSR principles, distribution and recovery are currently dealt with between clauses 3.6.5 and 3.18. Clause 3.6.5 contains the allocation principles for negative and positive IRSR, as well as the recovery for negative IRSR. Recovery and distribution of positive IRSR is dealt with separately in clause 3.18 through SRAs.

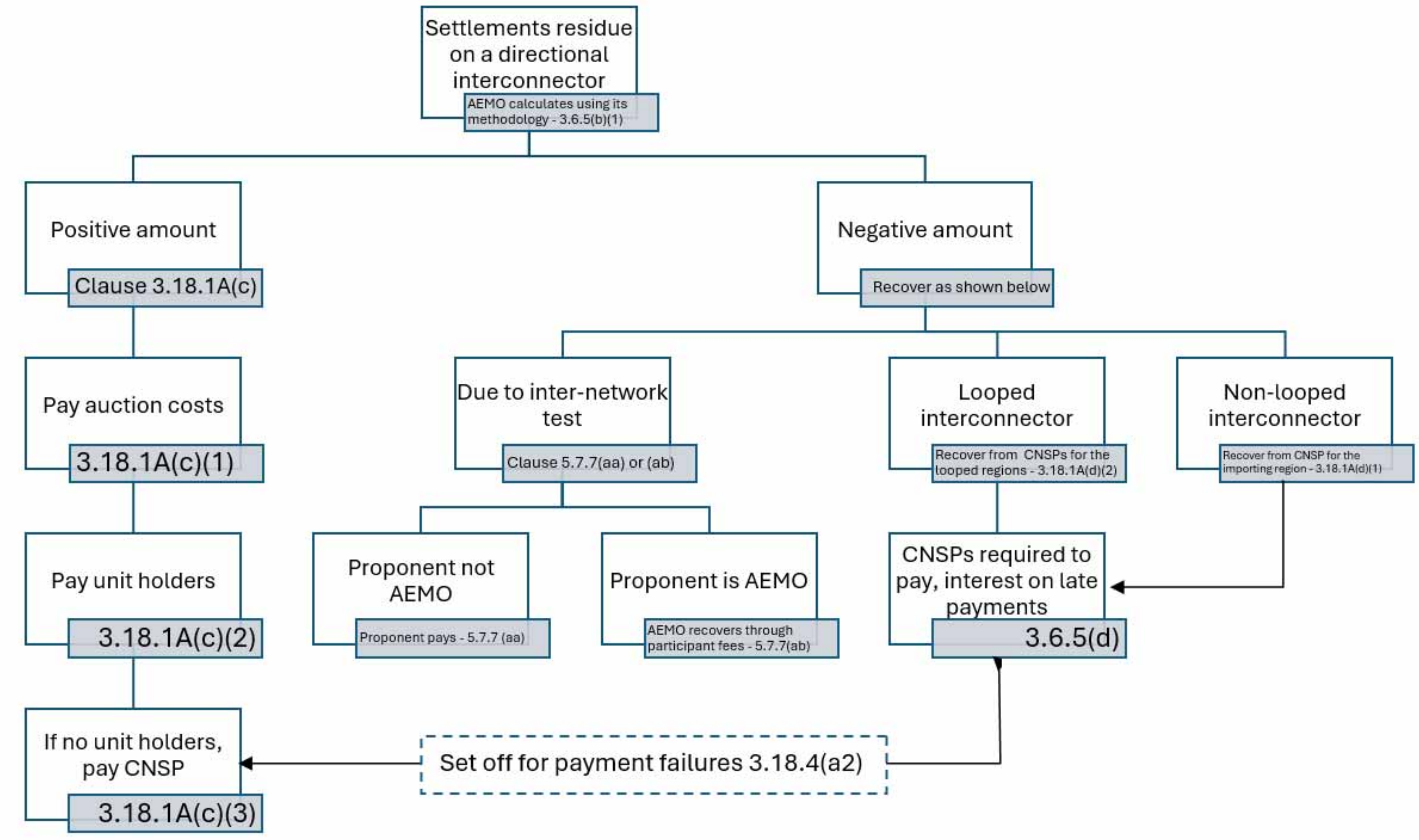
This current structure does not accurately reflect the staged process through which AEMO allocates and recovers negative and positive IRSR in practice (see Figure 3.3). Our draft rule would restructure clauses 3.6.5 and 3.18 to clearly separate the principles for the allocation and recovery of all forms of settlements residue (clause 3.6.5) from how AEMO recovers both negative and positive IRSR on directional interconnectors (clause 3.18).

The draft rule also clarifies that the mechanism used for recovery of settlements residue depends on how it arises, as follows:

- Settlements residue arising on regulated interconnectors is first allocated by AEMO to directional interconnectors,[93] and then:
  - positive amounts are used to pay auction costs first, and the balance is paid to SRA unit holders, or (if there are none) to the CNSP for the importing region[94]
  - negative amounts due to inter-network tests are recovered from the project proponent[95]
  - other negative amounts are recovered from CNSPs, with different calculations for directional interconnectors that form part of a loop and those that do not.[96]
- Settlements residue arising on interconnectors that are not regulated interconnectors is paid to, or recovered from, the CNSP for the importing region.[97]
- Intra-regional settlements residue is paid to, or recovered from, the CNSP for the region that has the intra-regional settlements residue.[98]

91 Submissions to the consultation paper: Alinta Energy, p. 1; Engie, p. 2; AEC, p. 2; Snowy Hydro, p. 2; Origin Energy, p. 3.
92 Shell Energy submission to the consultation paper, p. 2.
93 Draft rule, clause 3.6.5(b)(1) and clause 3.18.1A(b).
94 Draft rule, clause 3.18.1A(c).
95 Draft rule, clause 3.6.5(b)(2) and (3) and NER clauses 5.7.7(aa) and (ab).
96 Draft rule, clause 3.18.1A(d).
97 Draft rule, clause 3.6.3(b)(4). For completeness, this does not include the revenue that accrues to Market Network Service Providers (Basslink)
98 Draft rule, clause 3.6.5(b)(4).

Figure 3.3: The draft rule clarifies that the mechanism used for recovery of settlements residue depends on how it arises



The draft rule specifies that negative IRSR would be allocated to the CNSP in each region, consistent with the current approach in the NER. Currently the NER refers to the 'appropriate Transmission Network Service Provider' in clause 3.6.5(a)(3) and then defines the term within the clause. This can now be replaced with a reference to the CNSP because the *Providing flexibility in the allocation of interconnector costs* rule will change the definition of 'Co-ordinating Network Service Provider'.[99]

AEMO is currently the CNSP in Victoria, and is sometimes referred to as AEMO Victorian Planning in this capacity. Negative IRSR for Victoria would be allocated to AEMO Victorian Planning, and AEMO Victorian Planning would recover it from customers via transmission charges. The same would apply to SRA proceeds for Victoria.[100]

We note that the Victorian government has proposed reforms that may shift responsibility for transmission planning in Victoria from AEMO Victorian Planning to VicGrid. This transfer is subject to legislation passing Parliament next year.[101]

Negative IRSR and SRA proceeds for New South Wales and South Australia would continue to be allocated to Transgrid and ElectraNet respectively.

3.4.2 How the draft rule would be implemented

AEMO would need to carry out implementation work, including systems and procedures updates, before the draft rule takes practical effect. As noted in section 3.1.2, the draft rule would commence on 3 July 2025 and would begin to be used for the allocation of negative IRSR when the transmission loop is incorporated into NEMDE (expected to be in late 2026). AEMO has advised that it requires certainty on loop arrangements by March 2025 to allow sufficient implementation time. We plan to publish the final determination in late March 2025 which will meet the required timeline.

We expect AEMO's implementation work would include the following, but this list is not exhaustive:

- updating NEMDE to incorporate PEC and the transmission loop in dispatch, including updated clamping constraints,
- consulting on and publishing an updated clamping procedure that would apply to the looped interconnectors,[102]
- updating settlement systems to allocate IRSR to the CNSPs in looped regions in proportion to regional demand,

99 AEMC, Providing flexibility in the allocation of interconnector costs, final rule, 3 October 2024, clause 6A.29.1, https://www.aemc.gov.au/rule-changes/providing-flexibility-allocation-interconnector-costs.

100 For the avoidance of doubt, negative IRSR and SRA proceeds would not pass through Ausnet Services (the declared transmission system operator and Victoria's main TNSP).

101 Victoria State Government, 'About VicGrid', last updated 12 November 2024, https://www.energy.vic.gov.au/renewable-energy/vicgrid/about-vicgrid; Victoria State Government, 'Victorian Transmission Investment Framework', last updated 26 June 2024, https://www.energy.vic.gov.au/renewable-energy/vicgrid/victorian-transmission-investment-framework.
Note that any transfer would be enacted in a staged and carefully considered approach in close consultation with AEMO to enable an orderly transfer of responsibilities.

102 We note that the clamping procedure is currently published across multiple documents, including:
AEMO, Constraint Formulation Guidelines, v12, June 2023, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource ('Constraint Formulation Guidelines');
AEMO, SO_OP_3705 Dispatch procedure, v94, June 2024, pp. 37-38, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/power-system-operating-procedures ('AEMO Dispatch procedure');
AEMO, Automation of Negative Residue Management, v3.0, July 2021, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/policy-and-process-documentation ('Automation of Negative Residue Management').

- developing and publishing an updated Methodology for the allocation and distribution of settlement residue to reflect the allocation of negative IRSR to CNSPs under the draft rule (see below),
- consulting on and publishing, jointly with the Settlement Residue Committee, an updated version of the auction rules to introduce SA-NSW and NSW-SA unit categories and clarify any transitional issues.

AEMO may also update informational documents, such as the Guide to the Settlements Residue Auction, where relevant.[103]

The draft rule would require AEMO to publish a methodology for the allocation of IRSR

Currently, AEMO publishes the Methodology for the allocation and distribution of settlement residue to clarify how IRSR is allocated to directional interconnectors and then distributed to SRD unit holders and CNSPs. The draft rule would formalise a requirement in the NER for AEMO to publish this methodology. We consider that referencing the methodology in the NER would assist stakeholders in understanding the NER.

As noted above, AEMO would need to update the methodology to reflect the draft rule - specifically, how negative IRSR on the loop would be distributed amongst the relevant CNSPs in proportion to regional demand. AEMO would not be required to consult on this methodology.

The Commission notes feedback from AGL suggesting that "any changes to the regulatory framework for IRSR should be implemented within the [NER]", rather than guidelines or procedures, to promote clarity and consistency of application. Our draft rule maintains the existing approach in the NER, with IRSR allocation rules specified in the NER and detail supplemented by the AEMO methodology.

3.5 Transparency measures for IRSR outcomes will enable ongoing monitoring of loop outcomes

The Commission recognises that the IRSR outcomes of the new transmission loop are uncertain given the difficulty of modelling market outcomes. It will therefore be important to monitor IRSR outcomes in practice to observe whether the new allocation arrangements are performing as intended.

Currently, AEMO and the AER both publish information, and have monitoring powers, to enable stakeholders and market bodies to monitor IRSR and SRA outcomes and assess the operation of the NER, SRA arrangements, and clamping procedures for the loop. Market participants could use this information to inform investment or operational strategies related to the transmission loop. Market bodies and other stakeholders could also use it to support future analysis of whether the rules and procedures applied to the loop are operating as intended. As always, stakeholders have the option to submit a rule change request to the Commission if they consider there is a problem with the NER when the transmission loop is operating.

AEMO makes detailed IRSR data publicly available in its Market Management System (MMS) Data Model.[104] This includes positive and negative IRSR and power flows for each directional

103 AEMO, Guide to the Settlements Residue Auction, v4, October 2019, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/guide-to-settlements-residue-auction ('Guide to the Settlements Residue Auction').

104 AEMO, MMS Data Model Report, v5.4.0, 7 October 2024, pp. 807-809, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data.

interconnector and for each dispatch interval, updated daily. AEMO also publishes aggregated positive and negative IRSR data in its Quarterly Energy Dynamics (QED) reports.[105]

In addition, AEMO and the Settlement Residue Committee publish quarterly Settlement residue auction reports, to meet SRA reporting requirements.[106] Currently, these reports provide a breakdown of SRD units sold, clearing prices, and total positive and negative IRSR for each quarter. The draft rule would apply these existing arrangements to transmission loops such that AEMO would be required to report on the amount of negative IRSR attributed to directional interconnectors in each quarter, and the amount of negative IRSR recovered from each region in each quarter.[107] We consider this would support transparency because the information would show how each arm of the loop contributes to negative IRSR, and how each region is impacted.

The AER reports on efficiency and effective competition in the NEM at least every two years through the Wholesale electricity market performance report. This can include analysis of imports between regions, inter-regional congestion, IRSR, bidding behaviour, and contract markets.[108] The AER also publishes high price event reports and may occasionally publish special reports on specific issues, such as the 2012 report on congestion.[109] If the AER reported on matters relevant to IRSR or SRAs in these processes, we would expect that the AER would investigate the root causes of any significant IRSR events that may arise in the transmission loop (or outside of it) and whether such events are influenced by intra-regional congestion, disorderly bidding, or any other factors.

Recent amendments to the National Electricity Law (NEL) have expanded the AER's market monitoring functions and information gathering powers related to electricity and gas contract markets, effective from May 2024.[110] The AER could use these powers to gather information relevant to its wholesale market monitoring and reporting functions. This means that, where relevant, future AER market performance reporting could include discussions of SRD units and the SRA process, and whether there are any inefficiencies in the market or barriers to competition associated with SRAs.

105 AEMO, QED reports.

106 NER clause 3.13.5A(a)-(b).
AEMO, Settlement residue auction reports, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/settlement-residue-auction-reports.

107 Draft rule clause 3.13.5A(b)(4).

108 AER, Wholesale electricity market performance report 2022, December 2022, https://www.aer.gov.au/publications/reports/performance/wholesale-electricity-market-performance-report-2022.

109 AER, 'Prices above $5,000/MWh - July to September 2024', November 2024, https://www.aer.gov.au/publications/reports/performance/prices-above-5000mwh-july-september-2024; AER, 'Special report - The impact of congestion on bidding and inter-regional trade in the NEM', December 2012, https://www.aer.gov.au/publications/reports/performance/special-report-impact-congestion-bidding-and-inter-regional-trade-nem.

110 AER, 'Enhanced wholesale market monitoring guideline (2024)', November 2024, https://www.aer.gov.au/industry/registers/resources/guidelines/enhanced-wholesale-market-monitoring-guideline-2024.

4 We consider hedging options for positive and negative IRSR should be examined through a separate review

Box 5: Key points

We are concerned that currently:

- SRD units do not provide any hedge for consumers or market participants when IRSR is negative. This will become particularly problematic once PEC is commissioned and energised, given negative IRSR is likely to become more material.
- SRD units are sold 'at a loss' for consumers.

The Commission considers that these issues should be addressed as a priority for both 'radially' connected regions and future looped regions, as the issues affect both. Therefore, we intend to holistically review SRAs and SRD units through an AEMC initiated review. This could be as early as 2025-26, subject to our annual prioritisation process.

We also encourage stakeholders to submit rule changes to us if there are unintended consequences with PEC's operation.

In this chapter:

- Section 4.1 explains that the negative IRSR risk is unhedged, which disadvantages consumers.
- Section 4.2 explains that a financial instrument for negative IRSR may improve the management of inter-regional pricing risk for consumers and generators.
- Section 4.3 outlines a separate concern that SRD units may not be providing good value for money for consumers.
- Section 4.4 sets out our intention to review SRAs and SRD units in the future.

This rule change deals with negative IRSR in a transmission loop. Because of the imperative to have a solution to the allocation of negative IRSR before PEC becomes operational, we decided not to make changes to SRA arrangements in this rule change. We also note that stakeholder feedback strongly advised against changes to the SRA or SRD unit design.

However, while beyond the scope of this rule change, we think there is a case to review whether the current SRA arrangements are in the long-term interests of consumers because:

- IRSR will get more frequent with the loop, exacerbating these existing issues. This is discussed in section 3.2.1.[111]
- Current arrangements allow hedging of the positive IRSR but not negative IRSR. The Commission's initial view is that there could be benefits to consumers, TNSPs and generators from being able to hedge movements in negative IRSR. This is discussed in section 4.2.
- It is apparent that the positive hedging arrangements may not be delivering value to consumers. This is discussed in section 4.3.

111 AEMC, IRSR arrangements for transmission loops, consultation paper, section 2.2.2.

4.1 The current arrangements leave consumers fully exposed to the risk of negative IRSR

4.1.1 IRSR creates both risks for market participants and consumers

Price separation between regions creates risks to participants who import or export electricity. Exposure to IRSR also creates risks for consumers and TNSPs. Box 6 explains how there are volatility risks for both market participants and consumers associated with IRSR, depending on how prices separate between the importing and the exporting regions.

Box 6: An example of the inter-regional risk faced by market participants and consumers

Consider a vertically integrated energy company that operates generation in Victoria and serves retail customers in New South Wales. The prospect of price differences between the two regions represents inter-regional price risk for the business.

- If the New South Wales regional reference price (RRP) is *higher* than the Victorian RRP, the business is purchasing electricity at a high price for its retail customers and selling its generation at a low price. The business's exposure to both prices means in these situations, it makes a loss.
- If the business owns SRD units on the VIC-NSW directional interconnector and Victoria is exporting to New South Wales at the time, these units will pay out an amount proportional to the price difference, which will (partially or fully) hedge its loss.
- If the New South Wales RRP is *lower* than the Victorian RRP, the business is purchasing electricity at a *lower* price for its retail customers and selling its generation at a *higher* price. In this case, it still experiences inter-regional price risk – it is just that the risk results in an *increase* in profit.

Conversely, from the perspective of consumers in New South Wales:

- If the New South Wales RRP is *higher* than the Victorian RRP, imports create a benefit for consumers as positive IRSR lowers the overall cost of electricity.
- If the New South Wales RRP is *lower* than the Victorian RRP, imports create risks in the form of negative IRSR, which is solely borne by consumers.

It is important to have arrangements (like SRD units) that help manage these risks as it is not possible to avoid IRSR arising in the NEM. This is due to the NEM's regional pricing model. As we discussed in the consultation paper, negative IRSR can arise for a number of reasons in the process of a non-linear power flow system being translated into a linear model in NEMDE.[112] This is simplified further again when prices are set on a regional basis.

Hedging instruments can help parties manage these risks of IRSR. In the example in Box 6:

- Hedging the risk of positive price separation, through SRD units, is valuable for the business to avoid it making a loss. However, consumers can still benefit from the hedge because it can lead to smoother prices, provided that the revenue consumers receive from SRA payouts is sufficiently close to the average value of positive IRSR over time.
- The converse also holds. Hedging the risk of negative price separation is valuable for consumers in avoiding spikes in prices. But for market participants, an increase in negative IRSR broadly matches the additional revenue they would receive from wholesale prices in the

112 Ibid., Appendix B.

exporting region (Victoria) being higher than in the importing region (NSW). Therefore, market participants could still benefit from taking on this risk, if the amount they are paid (to receive negative IRSR) is sufficiently close to the actual cost of negative IRSR over time.

Consumers (who would otherwise 'own' the IRSR) and market participants who are exposed to inter-regional pricing risk are 'natural counterparties' - both parties' risk is reduced by the consumer 'selling' the IRSR to market participants exposed to inter-regional pricing risk.

4.1.2 IRSR hedging arrangements can benefit consumers through encouraging competition, trade and smoothing variable cash flows

Hedging IRSR through financial instruments plays an important role in promoting competition and efficient entry into the market, which supports lower cost electricity for consumers. These financial instruments, or SRD units, do this by managing inter-regional price risk. There are four key benefits for consumers.

First, hedging IRSR through SRD units supports retail competition. Without SRD units, market participants who trade inter-regionally are exposed to large cash flow volatility, because the price they earn when they supply electricity (the export price) can vary substantially relative to the cost that is incurred when their customers consume electricity (the import price). SRD units help retailers and gentailers manage their exposure to large cost differentials relative to their competitors in the region who do not rely on imports.[113]

Second, hedging can support consumer access to cheaper electricity generated in other regions. By providing an instrument to manage inter-regional price risks, hedging encourages agreements to supply consumers from areas where costs are lower.

Third, hedging IRSR through SRD units encourages efficient investment. By providing a tool to manage the movements in wholesale prices across regions, SRD units work in concert with wholesale and contract markets to provide clear incentives for generators and large loads to locate in appropriate places, without being biased towards a particular region.

Finally, and less commonly discussed, SRD units provide a mechanism for *consumers* to hedge the variable cash flows that would otherwise arise were they to receive IRSR directly, as was the case prior to the introduction of SRD units in 1999. Consumers are generally risk averse, and so all else equal it is preferable for them to 'lock-in' revenue in the form of fixed SRA revenue as opposed to being unhedged to IRSR.

4.1.3 Transmission loops could increase consumers' exposure to the risk of negative IRSR

Currently, we only have hedging instruments for market participants to hedge the risks from positive IRSR. This is an SRD unit, where participants pay to receive a share of the positive IRSR to offset the associated cost to them when prices in the importing region are higher than prices in the exporting region.

However, there is no equivalent for the benefit that arises when prices in the importing region are lower than prices in the exporting region. Participants receive any positive benefit from price separation, while consumers bear the entire cost of any associated negative IRSR.

AEMO's clamping arrangements for negative IRSR currently place a limit on this risk for consumers (although we note that negative IRSR can still reach significant levels over the course

113 The following submissions to the consultation paper commented on the hedging mechanism of SRD units: AFMA, pp. 1-2; Snowy Hydro, p. 2; AEC, p. 2.

of a year).[114] In effect, clamping provides a market-wide 'hedge', in much the same way that the administered price cap mechanism provides a market-wide hedge against sustained high prices within a region.

However, this will likely change with a transmission loop. Large negative IRSR is possible with the introduction of PEC. As discussed in section 2.2.4, our draft rule would not require AEMO to clamp negative IRSR in cases where there is net positive IRSR around a loop, such as that created by PEC. The risks are therefore asymmetric because consumers are exposed to the prospect of virtually unlimited and unhedged negative IRSR, whereas market participants with these inter-regional positions benefit from export prices being higher than import prices (Box 6).

4.2 Creating hedging arrangements for negative IRSR could help protect consumers from this risk

SRD units already provide a method for these parties to hedge the risk of price separation resulting in **losses** to market participants. However, there is no hedging instrument for price separation that results in **profits** to market participants and costs to consumers. In principle, a hedging instrument for these cases could also provide benefits to consumers and market participants:

- Consumers face a clear negative risk – the risk of being allocated an uncertain amount of negative IRSR. This is allocated to consumers through transmission prices, as outlined in Box 4 in section 3.2.2. 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.

These factors are summarised in Table 4.1 for both positive and negative IRSR.

This suggests that the arrangements for inter-regional price risk management – the fundamental intent of SRD units – may be improved by creating hedging arrangements for negative IRSR.

Including all IRSR (positive and negative) in SRD units broadly replicates the arrangements prior to 2009. The rationale for changing to the existing arrangements is outlined in Box 7.

114 For example, AEMO's Q3 2024 QED report shows about $27 million of cumulative negative IRSR accruing between New South Wales, South Australia, and Victoria in Q1 2024, compared to about $90 million of positive IRSR for that quarter (https://aemo.com.au/en/energy-systems/major-publications/quarterly-energy-dynamics-qed).

Table 4.1: Impact of hedging IRSR for market participants and consumers

	A market participant exposed to inter-regional pricing risk	Consumers exposed to variable IRSR risk
Positive IRSR	Willing to make a fixed upfront payment to receive positive IRSR, as this could reduce the volatility of their overall return, for the same expected level of return. This hedges positive inter-regional pricing risk, which would otherwise result in losses.	Willing to be paid fixed upfront payment to forego variable positive IRSR.
Negative IRSR	Willing to receive a fixed upfront payment to be exposed to negative IRSR, as this could reduce the volatility of their overall return, for the same expected level of return. This hedges negative inter-regional pricing risk, which would otherwise result in profits.	Willing to make fixed upfront payment to avoid variable negative IRSR.

Box 7: The changing use of SRD units to hedge IRSR

The current arrangements for IRSR - where negative IRSR flows direct to consumers via TSNPs and positive residues flow to SRD unit holders - were introduced in 2009. Prior to this, both positive and negative IRSR were allocated to SRD unit holders.

The rationale for the current arrangements is discussed in the AEMC's 2008 Congestion Management Review:

> The current Rules [as was in 2008] stipulate that for each directional interconnector, positive residues can be used (within the same billing week) to net off any negative residues that might occur as a result of counter-price flows. Other things being equal, this will reduce the funds paid out to IRSR [i.e., SRD unit] holders and therefore reduce the firmness of the hedge.

In 2009 the Commission made a rule change broadly consistent with its recommendations of its Congestion Management Review because it would "improv[e] the 'firmness' of the IRSR unit [SRD unit] as a hedging instrument".

Note: Positive and negative IRSR were 'netted off' weekly prior to 2009. If negatives were less than positives over the week, then the negatives were allocated to SRD unit holders. If negatives exceeded positives over the week then the *excess* negatives were recovered through future SRA fees (between 1999 and 2006) or deducted from consumers (between 2006 and 2009). See AEMC, IRSR arrangements for transmission loops, consultation paper, appendix D. Also see AEMC, Congestion Management Review, final report, June 2008, p. 159; and AEMC, Arrangements for Managing Risks Associated with Transmission Network Congestion, final determination, August 2009, p. 25.

Consistent with this position, in response to the consultation paper for this review, stakeholders overwhelmingly argued that existing SRD units should not be amended to include negative IRSR on the basis that it would undermine the risk management qualities of the SRD units by reducing their firmness.[115] We note that consumer groups did not comment on this issue, however.

It is true that allocating negative IRSR to SRD unit holders would reduce the funds paid to them. However, it is not clear why this reduction would reduce the firmness of the hedge, when the

115 AEMC, Arrangements for Managing Risks Associated with Transmission Network Congestion, final determination, 13 August 2009, p. 25, https://www.aemc.gov.au/rule-changes/arrangements-for-managing-risks-associated-with-tr.

objective of a risk management instrument is to minimise profit volatility, not maximise revenue or profit. Minimising profit volatility appears to be achieved by allocating negative IRSR to existing SRD units, because it more completely hedges the inter-regional pricing risk for market participants and IRSR risk for consumers.

An alternative approach to including all IRSR (positive and negative) in SRD units would be to introduce a new set of negative SRD units (which pay out only the negative IRSR) alongside the existing positive SRD units (which pay out only the positive IRSR). We did not consult on this option, and note it may have the advantage of leaving the existing instruments unchanged.

Any consideration of creating hedging products for negative IRSR would also 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 (and positive IRSR) could provide benefits in addressing cash flow risks for TNSPs. Currently, TNSPs reset transmission prices on an annual basis. This means that TNSPs need to hold additional cash, or pay to maintain lines of credit, to fund fluctuations in negative IRSR they need to pay within a financial year (or manage fluctuations in the revenue they would receive from positive IRSR).

TNSPs would face less risk (and incur lower costs) to the extent that:

1. the negative IRSR they incur, or SRA proceeds they receive, were more stable and predictable, and
2. the difference in the timing of cash flows is minimised; that is, a shorter length of time between when periodic movements in negative IRSR and SRA proceeds accrue, to when they receive a corresponding change in revenue from customers.

4.3 The current hedging arrangements for positive IRSR do not seem to be providing value to consumers

The Commission also considers it would be worthwhile looking at whether the current SRA arrangements are providing value to consumers.

As outlined in section 4.1.2 above, SRD units have a number of important benefits in promoting competition by: supporting increased trade, providing more efficient investment signals for new generation, and managing the risks that retailers and gentailers face in serving customers across regions.

The Commission is concerned that the benefits of SRAs for consumers could be outweighed by the fact that the revenue consumers are receiving through SRA proceeds has proven to be much lower than the average value of positive IRSR over time.

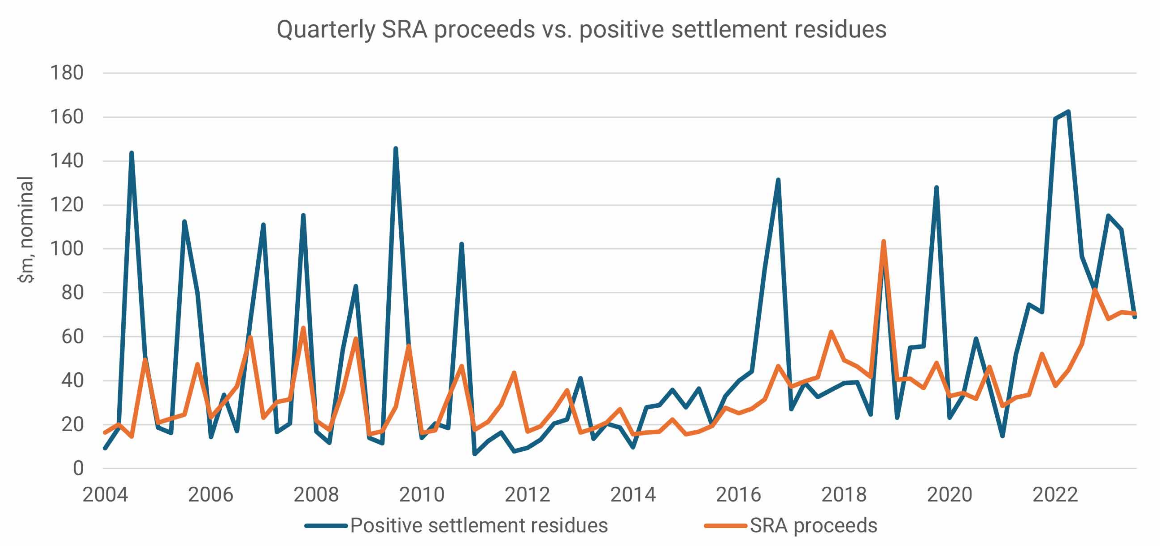
As SRD units are auctioned over the three years prior to the quarter that the residues accrue, it is reasonable that expected positive IRSR may not align to SRA proceeds in any given quarter. However, over a 20-year timespan, auction proceeds are persistently below actual positive residues accrued.

Data shows that, in the period from Q2 2004 to Q1 2024 (20 years, 80 separate quarterly auctions), SRD unit holders have paid consumers $2.9b, and have received $4.0b in IRSR, in nominal terms. In effect, consumers have made a loss of $1.1b in nominal terms on these financial instruments. For every $1 of IRSR sold, consumers have received $0.72 in return.

This result is somewhat surprising, because SRD units ostensibly provide valuable risk management benefits in reducing volatility for market participants who trade inter-regionally, as outlined in section 4.2 above. 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.

Perhaps the SRAs are not sufficiently competitive, resulting in lower returns for consumers. These results have led the Commission to question whether it is in the long-term interest of consumers to sell the SRD units at the price determined via the SRA, if the direct benefits from SRD units are modest and/or consumers are receiving uncompetitively low prices. Conceivably, consumers would be better off overall not selling them, or only selling them above a certain reserve price.

Figure 4.1: SRA proceeds are persistently lower than actual positive residues



Source: AER data, 'Quarterly settlement residues and settlement residue auction proceeds', June 2024, https://www.aer.gov.au/industry/registers/charts/quarterly-settlement-residues-and-settlement-residue-auction-proceeds.

4.4 The Commission intends to review SRD units and SRAs in 2025-26

Given the issues discussed in section 4.1 and section 4.3, the Commission intends to review the current arrangements for hedging IRSR through SRD units and the associated SRA processes.

Based on our current work program and priorities, we intend to conduct this review in 2025-26. In broad terms, we expect the review would cover:

- whether the sale of SRD units represents good value for consumers, and whether and how value might be improved,
- whether the SRD units are designed in a manner that best enables market participants to manage inter-regional price risk, and for consumers and TNSPs to best manage IRSR risk,
- the arrangements for SRD units and SRAs for both existing 'radially' connected regions and future looped regions (i.e., imminently SA, NSW and Victoria upon the completion of PEC). That is, the review would not just cover the SRD units and SRAs between SA, NSW and Victoria, but also the Tasmania-Victoria, and NSW to Queensland arrangements,
- the efficiency of the current arrangements for managing IRSR cash flows, and whether there is a way that cash owed to consumers could move through to consumers more quickly, as well as reducing the impost on cash flow distributions to TNSPs.

4.4.1 Reviewing PEC's IRSR arrangements could be considered at a later date

PEC's operation will give us important data about IRSR outcomes in transmission loops, which has been difficult to model in theory. In responding to the consultation paper, stakeholders suggested that the AEMC should conduct a review into the arrangements for PEC.[116]For example, the Australian Energy Council (AEC) suggested the AEMC review PEC's operation "no later than after two years of full PEC operation", reflecting the complexity of PEC and uncertainty surrounding its operation.[117]

A review of IRSR arrangements as they operate in PEC could be considered in the future, although it is possible that a more immediate review into SRAs could address any IRSR issues arising in the loop. The AEMC's rule change process may be used if market bodies or participants identify concerns regarding the outcomes of the PEC transmission loop once it is operating.

116 Submissions to the consultation paper: AGL, p. 2; Engie, p. 1; AEC, p. 2; JEC, p. 1.

117 AEC submission to the consultation paper, p. 2.

A Rule making process

The rule change process 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 is using a longer-than-standard process for this rule change due to the complexity of the issues involved.[118] We will publish the final determination and final rule on 27 March 2025.

You can find more information on the rule change process on our website.[119]

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 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:[120]

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 TNSPs for those arms.
2. When net residue for the loop is negative, negative IRSR accruing on any individual arm would be allocated directly to the importing TNSP 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 TNSPs, 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.[121]
5. The interconnectors forming the loop would only be subject to clamping when the net residue for the loop is negative.[122] 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 for more detail.

118 Notices under section 107 of the NEL extending the time for making the draft and final rule were published on 8 August 2024.

119 See our website for more information on the rule change process: https://www.aemc.gov.au/our-work/changing-energy-rules.

120 AEMO rule change request, pp. 14-17.

121 Ibid., pp. 10-11.

122 Ibid., p. 11.

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.[123] 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.[124] See appendix C.3.

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:[125]

> 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 corresponding positive IRSR. AEMO's proposed rule seeks 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.[126]

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.[127]

In addressing why the proposed rule treats net positive and net negative cases differently, AEMO noted that:[128]

> 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.[129]

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.

123 Ibid., p. 9.
124 ACIL Allen, 'Modelling the settlement effects of PEC'.
125 AEMO rule change request, p. 9.
126 AEMO, PEC Market Integration final report, pp. 41-42.
127 AEMO rule change request, p. 15.
128 Ibid., p. 9.
129 AEMC, IRSR arrangements for transmission loops, consultation paper, pp. 17-18.

AEMO's rule change request was developed following its PEC Market Integration body of work, carried out between 2022 and early 2024.[130] 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.[131]

A.3 The process to date

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.[132] A consultation paper identifying specific issues for consultation was also published. The Commission also extended the timeframe for the draft and final determinations due to the complexity of the issues in the rule change request. The final determination will be published on 27 March 2025.

Submissions to the consultation paper closed on 5 September 2024. The Commission received 12 submissions as part of the first round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination.

130 AEMO, PEC Market Integration Papers.

131 AEMC, IRSR arrangements for transmission loops, consultation paper, p. 37.

132 This notice was published under section 95 of the NEL.

B Regulatory impact analysis

The Commission has undertaken regulatory impact analysis to make its draft determination.

B.1 Our regulatory impact analysis methodology

The Commission analysed these options: the rule proposed in the rule change request; a business-as-usual scenario where we do not make a rule; and a more preferable rule, where negative IRSR is reallocated amongst all looped regions in proportion to the annual electrical energy consumption of each and is likely to better contribute to the achievement of the NEO.[133]

Chapter 2 presents our assessment of our more preferable rule against our assessment criteria.

We identified who would be affected and assessed the benefits and costs of each policy option

The Commission's regulatory impact analysis for this rule change used qualitative and quantitative methodologies. It involved identifying the stakeholders impacted and assessing the benefits and costs of policy options. The depth of analysis was commensurate with the potential impacts. The Commission used quantitative modelling that was undertaken by AEMO ahead of the rule change request being submitted.

While the Commission appreciates the value of a robust estimate of the magnitude of negative IRSR and how much it could vary, we have not undertaken further modelling in this rule change. This is due to the fact that we do not consider that market modelling would provide us with valuable new information, beyond what AEMO has demonstrated. Modelling the extent of negative IRSR would be complex because IRSR is sensitive to a wide range of factors, including spot prices, demand patterns, network constraints, and participant bidding behaviour. The loop may also influence investment and operational decisions. These factors are difficult to forecast, and so modelling results may turn out to be inaccurate (see section 3.2.2). In addition, this rule change needs to be completed by March 2025 to allow sufficient implementation time before PEC becomes operational.

The Commission focused on the types of impacts within the scope of the NEO.

Table B.1 summarises the regulatory impact analysis the Commission undertook for this rule change. Based on this regulatory impact analysis, the Commission evaluated the primary potential costs and benefits of policy options against the assessment criteria. The Commission's determination considered the benefits of the options against the costs.

133 AEMC, IRSR arrangements for transmission loops, consultation paper, section 3.3.

Table B.1: Regulatory impact analysis methodology

Assessment criteria	Primary costs – Low, medium or high	Primary benefits – Low, medium or high	Stakeholders affected	Methodology QT = quantitative, QL = qualitative
Outcomes for consumers	Distributional impacts of the proposed solution and any alternative options (M)	This has both costs and benefits. We need to ensure, as far as practicable, the rule change will distribute costs in a way that does not result in significant unfair wealth transfers between customers in different regions (M)	• Market participants, including generators and retailers • All consumers	• QT: ACIL Allen, 'Modelling the settlement effects of Project Energy Connect', July 2023, (commissioned by AEMO for their PEC market integration work). • QL: Stakeholder feedback to assess impact of proposed distributional impacts. • QL: Systematic analysis of possible outcomes to assess distributional impacts of different options. • QT: Consideration of potential magnitude of extreme negative IRSR and its impacts on consumers.
Principles of market efficiency	Nil	Benefits of avoiding increased clamping under PEC (M)	• Market participants, including generators and retailers • All consumers	• QL: Assessing the benefits of avoiding clamping (or costs of increased clamping) under PEC, drawing on AEMO's work and stakeholder consultation.
Principles of market efficiency	Impacts on TNSPs of changed magnitude/ timing of cash flows from settlements residues (and any flow-throughs to network consumers) (M)	Nil	• TNSPs (and consumers) in the looped regions - they will either pay negative residues or receive SRA proceeds	• QL: Feedback from TNSPs to understand impacts.

Assessment criteria	Primary costs – Low, medium or high	Primary benefits – Low, medium or high	Stakeholders affected	Methodology QT = quantitative, QL = qualitative
Principles of good regulatory practice	Implementation costs for AEMO and others (L)	Nil	• Market participants that must comply with new obligations • AEMO - responsible for implementing solution into NEMDE and managing the new settlements	• QT: AEMO advice on costs and impacts of system changes. • QL: Advice from other stakeholders on any other implementation costs not captured by AEMO.

C Current arrangements and technical background

In this appendix:

- Appendix C.1 explains what IRSR is and how it occurs.
- Appendix C.2 outlines the current arrangements for the allocation of positive and negative IRSR.
- Appendix C.3 explains why the transmission loop formed by PEC is expected to cause larger and more frequent negative IRSR, including a discussion of the spring washer effect.
- Appendix C.4 provides background on clamping, including the current process, governance, and AEMO's proposed approach to clamping for a transmission loop.
- Appendix C.5 outlines our previous rule changes and reviews that have considered IRSR.

C.1 Settlements residue definitions and concepts

'Settlements residue' in an electricity market is the surplus or deficit of funds that arises when the amount that load pays for energy is different to what generators are paid.[134] There are two types of settlements residue in the NEM:

- **Inter-regional** settlements residue (IRSR) occurs when prices between regions in the NEM differ, or separate, and energy is flowing across an interconnector between those regions. This happens frequently. Prices can differ between regions due to transmission losses and due to congestion on the transmission lines within and between regions.
- **Intra-regional** settlements residue is related to physical losses from transmitting electricity within a region.

This rule change is concerned with inter-regional settlements residue (IRSR).

AEMO calculates IRSR for each pair of interconnected regions in each dispatch interval in each direction by multiplying:

- the difference in the regional reference price between the two NEM regions, and
- the amount of energy flowing between those two regions.[135]

IRSR can be positive or negative.

- **Positive IRSR** occurs when electricity flows from a lower-priced region to a higher-priced region. There is a settlement surplus – the amount of money received from energy consumers in the importing region is greater than the amount paid to generators in the exporting region for the energy that flows across the interconnector.
- **Negative IRSR** occurs when electricity flows from a higher-priced to a lower-priced region (known as a **counter-price flow**). There is a settlement deficit – energy consumers in the importing region pay less than the amount paid to generators in the exporting region for the energy that flows across the interconnector.

Positive IRSR is a common outcome and occurs whenever there is price separation between regions, with imports into the higher-priced region. With the existing NEM interconnector configuration, a small amount of negative IRSR can also arise as part of normal operation.[136] Large

134 See NER definition, 'settlements residue'. A 'settlement' is the activity of producing bills and credits for market participants.

135 There is also an adjustment for losses.

136 For more information see: AEMO, Guide to the Settlements Residue Auction, p. 7, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/settlements-residue-auction/guide-to-settlements-residue-auction.

amounts of negative IRSR are more likely to be caused by significant intra-regional congestion and/or disorderly bidding.

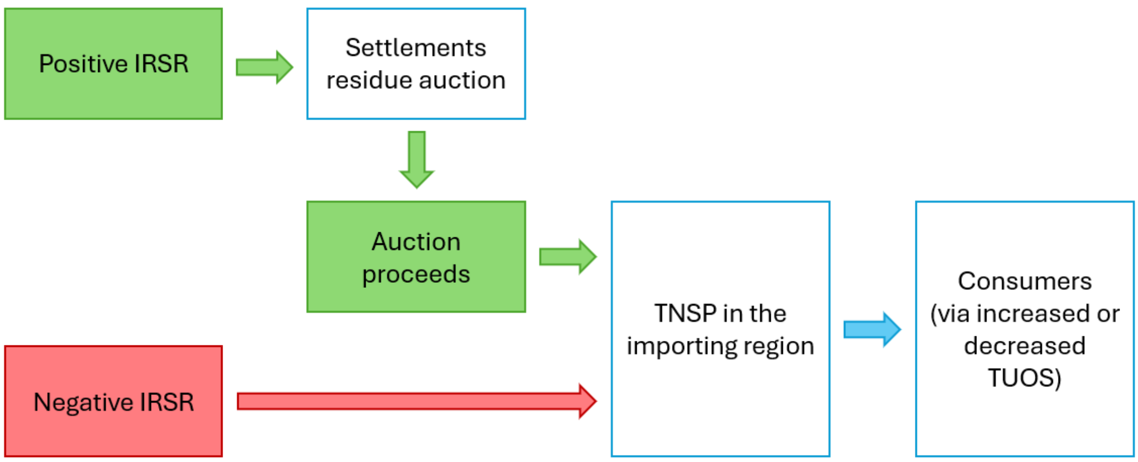
C.2 Current arrangements for the allocation of negative IRSR

The current rules specify different methods for managing positive and negative IRSR. However, both types of residue are ultimately passed through to consumers in the region that is importing the electricity, as shown in Figure C.1.

Negative IRSR is allocated directly to the TNSP in the importing region.[137] TNSPs recoup the resulting costs through transmission use of system (TUOS) charges levied on customers. (See appendix C.2.1 for more detail on the arrangements for negative IRSR.) However, AEMO limits the magnitude of negative IRSR by applying negative residue management constraints, known as clamping. (See appendix C.4 for more detail on clamping.)

Positive IRSR is distributed through an auction system to market participants and energy traders. Instead of receiving positive IRSR directly, the importing TNSP receives the proceeds of the auction.[138] TNSPs pass this revenue through to customers via reduced TUOS charges. See appendix C.2.2 for more detail on settlement residue auctions (SRA).

Figure C.1: Stylised illustration of positive and negative IRSR allocation under existing rules



Source: AEMC, IRSR arrangements for transmission loops, consultation paper, p. 8.

C.2.1 Negative IRSR is allocated to the importing TNSP and then flows to consumers

AEMO uses clamping to limit the impact of large negative IRSR, but not to prevent it entirely. Any negative IRSR that accrues before an interconnector is clamped are allocated to the TNSP in the importing region. That is, the TNSP must pay the settlements deficit back to AEMO.[139] This allocation is determined for each dispatch interval, but TNSPs are invoiced by AEMO on a weekly basis, aligning with NEM settlement.

As a regulated entity, TNSPs recover the cost of negative IRSR from transmission customers via TUOS charges. TUOS charges are paid by transmission-connected customers that include distribution network service providers (DNSPs) and some large industrial customers. DNSPs in

137 NER clause 3.6.5(a).
138 NER rule 3.18.
139 NER clause 3.6.5(a).

turn recover their costs from end customers (via retail tariffs). This means that end users in the importing region, including households and small businesses, will ultimately bear the cost of negative IRSR. Because of the way transmission prices are set, there can be a delay of up to two years between the accrual of negative IRSR and its recovery from customers (see Box 4 in section 3.2.2).

Where there is more than one TNSP in the importing region, the rules allocate negative IRSR to the CNSP in that region.[140] This means that negative IRSR for Victoria is allocated to AEMO, in its capacity as transmission planner for Victoria, and AEMO recovers it from transmission customers. Negative IRSR for New South Wales and South Australia is allocated to Transgrid and ElectraNet respectively.

C.2.2 Positive IRSR is auctioned as a hedging instrument and the proceeds flow to consumers

Participants in SRAs bid for the right to receive portions (units) of future positive IRSR. SRAs are held quarterly by AEMO up to three years in advance. That is, auction participants can purchase the rights to positive IRSR that will accrue up to three years in the future.[141]

Parties eligible to participate in the auctions include retailers, generators, traders, and Integrated Resource Providers.[142] TNSPs are specifically excluded by the NER due to the potential for them to influence interconnector flows.[143]

In the auctions, SRD units are auctioned for each 'directional interconnector' and the IRSR is calculated for the directional interconnectors. There are two directional interconnectors for each pair of regions that are connected, one for each direction of flow regardless of the number of physical interconnectors.[144] (See Box 2 in section 3.1.1).

The positive IRSR for a directional interconnector is paid out to the respective unit holders, in the quarterly period to which the SRD units relate. In relation to any dispatch interval where the IRSR is negative, the SRD unit pays out zero. There is a minimum payout of $10 per SRD unit. AEMO deducts auction expense fees from positive residue payouts.[145]

The auction proceeds are distributed to the relevant importing TNSPs, and passed through to consumers via reduced TUOS charges. The importing TNSP also receives, and passes through, the positive residues from any SRD units that are not sold at auction.[146] For example, the proceeds from selling VIC-NSW units, and the IRSR from any unsold VIC-NSW units, would go to the New South Wales TNSP, TransGrid.

Note that the design of settlements residue auctions is largely AEMO's responsibility. The NER provides the principles and core requirements for SRAs and sets basic requirements around eligibility, information provision, auction fees, and the role of the settlement residue committee (SRC).[147] AEMO administers the auctions in accordance with the [Settlements Residue Auction Rules](), which are developed by AEMO and subject to the approval of the SRC.[148] The Commission

140 NER clause 3.6.5(a)(4B).

141 AEMO, SRA Rules, p. 11.

142 Integrated Resource Provider is a NER participant registration category covering owners or operators of bidirectional units (batteries), among other things.
AEMC, Integrating energy storage systems into the NEM, final determination, pp. 89-91, December 2021, https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

143 NER clause 3.18.2(b); AEMO, SRA Rules, pp. 8-9.

144 AEMO, Guide to the Settlements Residue Auction, p. 7.

145 Ibid., p. 14; AEMO, SRA Rules, pp. 31-32.

146 NER clauses 3.6.5 and 3.18.4.

147 NER rule 3.18.

148 Ibid.

understands that AEMO intends to maintain the same auction design for the upcoming PEC interconnector.

AEMO maintains documentation providing more information about the SRAs, including:

- the Guide to the Settlements Residue Auction,
- the Methodology for the allocation and distribution of settlements residue, and
- quarterly auction reports.

C.3 Transmission loops can lead to more frequent negative IRSR

A transmission loop is a configuration of regulated interconnectors that links three NEM regions in a closed loop (see section 3.1.1). The NEM's first transmission loop will be formed upon the completion of the PEC interconnector and its integration into NEMDE.

PEC (Project EnergyConnect Stage 2) will be a 330kV interconnector between South Australia and New South Wales with a capacity of approximately 800 MW. It is currently under construction and is due to be fully operational in Q4 2027, with a capacity of 500MW being released from approximately Q4 2026.[149] Further information on the PEC project can be found on the Project EnergyConnect website.

C.3.1 The spring washer effect can cause negative IRSR as part of efficient dispatch in a loop

Power flows differently in a transmission loop compared with a radial configuration. This can lead to different wholesale pricing outcomes – and different resulting IRSR – in a loop than we expect to see in radial configurations.

Power flows around a loop are governed by Kirchhoff's Law, a law of physics which states that power will flow along all network paths from a generator to a load. In other words, the power flow will be 'shared' between the paths. This is a physical law that cannot be overridden in dispatch. (See appendix C of our consultation paper.)

When a binding constraint is present in a transmission loop, counter-price flows can be normal and necessary to support overall efficient dispatch outcomes. This is due to the 'spring washer effect' – a pricing phenomenon which arises when the loop is affected by a binding constraint (see Box 8). It is so named because it involves a large price separation across the constraint with prices gradually increasing from the lowest to the highest price around the loop, which resembles the shape of a spring washer as shown in Figure C.2. In certain circumstances, this can lead to an efficient counter-price flow, as explained below. Constraining this flow (clamping) would reduce the overall efficiency of dispatch.

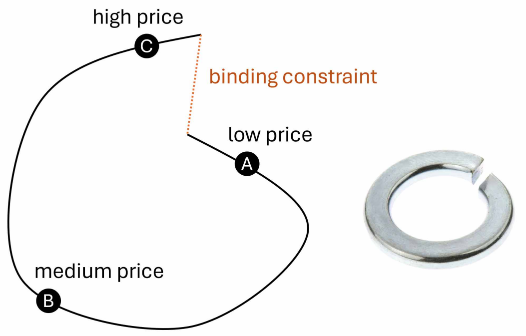
Box 8 presents a simple example of the spring washer effect and the general principles are summarised following.

149 PEC system integration industry update, April 2024.

Box 8: Simple example of the spring washer effect and counter-price flows

The spring washer pricing pattern is illustrated in Figure C.2. In this simple example, energy is generated at nodes A and B and the majority of the load is at node C. There is a constraint binding between nodes A and C.

Figure C.2: Prices around a loop form a spring washer pattern when a constraint binds



Generators at node A will send most of the electricity they generate along the shortest route to C, due to Kirchhoff's Law. This route passes through the constrained line. As a result, generators at node A strongly contribute to congestion in the local area. This means the electricity they generate is less 'useful' (considering the largest load is at C), so the local price at A is low.

Moving away from the constraint, a higher proportion of the energy generated at node B goes directly to C, without crossing the constraint. A small proportion of electricity generated at B also flows via A due to Kirchhoff's Law. Generation at node B has a weaker impact on the constraint and therefore a higher local price. The highest local price occurs just downstream of the constraint, at node C.

The resulting prices around the loop resemble a spring washer as shown in Figure C.2. Prices are very high immediately one side of the constraint (C), very low on the immediate other side of the constraint (A), and gradually change as we progress around the loop in between (B).

Depending on the dispatch conditions, the spring washer effect can sometimes lead to an efficient counter-price flow. As noted above, some of the power generated at node B must flow from node B to node C via node A, creating a counter-price component of flow from B to A. This flow is netted off against the flow in the other direction (electricity generated at A). If the conditions are right, the power flow from generators at B can exceed the power flow coming from A. Then the total flow on the B-A arm will be in the counter-price direction, towards A.

Negative settlements residue would then accrue on the B-A arm, since energy is flowing to the lower-priced node A. Node A acts as a 'transition node' since power flows from node B through node A to supply node C.

Here, we have used counter-price flow on the B-A arm as an illustrative example, but the spring washer effect could also cause counter-price flows on the C-B arm of the same loop, or both at the same time.

Source: AEMC, IRSR arrangements for transmission loops, consultation paper, p. 16; Lu F, Energy Market Company, 'Spring Washer Effect – A Market Clearing Engine Study of the NEMS', October 2004, https://www.home.emcsg.com/publications?q=&sort=date-asc&year=0&filter1=-1&filter2=-1&filter3=-1&page=0; Chin YC, Nair NC and Chakrabarti BB, 'Impacts of Loop Flow on Electricity Market Design', November 2006, https://www.researchgate.net/publication/224060669_Impacts_of_Loop_Flow_on_Electricity_Market_Design; TranspowerNZ, 'The Spring Washer Effect', video playlist, October 2013, https://www.youtube.com/watch?v=pezUSbI9OUY&list=PLXUccGn4ptEO5e0-MV37_vWPWerhB8yak.

If constraints are introduced on the loop (additional to the loop flow constraint), NEMDE needs to balance the electricity generated in different locations around the loop to keep the power flows within the constraints. This is complex because generators send power in both directions around the loop, as noted above. The need to balance generation around the loop can impact local prices quite significantly as the dispatch engine needs to adjust different combinations of generators up or down to meet the next MW of demand while not violating the constraints.[150]

When there is a binding constraint in a transmission loop, the spring washer pricing pattern emerges as explained in Box 8.

The spring washer effect can sometimes – but does not always – lead to counter-price flows. These flows can be thought of as taking a longer route to the load, as required by Kirchhoff's Law, via a 'transition node' that may have a different price.

Counter-price flows within a loop will translate to negative IRSR when the loop passes through more than two NEM regions.[151] Loops in a general sense are currently quite common in the transmission and distribution networks within regions. However, these loops do not create negative IRSR since they do not cross region boundaries and the same regional price is applied to all generators and loads within the region.[152] Network loops would not be considered transmission loops (*parallel interconnector configurations*) under the draft rule because a transmission loop must cross into three regions (see section 3.1.1).

Note that AEMO will use a full loop representation of the new interconnector in NEMDE, and not the alternative micro-slice representation. This means AEMO will represent PEC as an interconnector linking the New South Wales and South Australia regions, which are treated separately by the dispatch engine.[153] AEMO will then introduce a 'loop flow constraint' to represent the way that power physically flows around the loop (i.e. implementing Kirchhoff's Law in NEMDE).[154]

C.3.2 Modelling suggests that negative IRSR will occur frequently in efficient dispatch

AEMO commissioned modelling by ACIL Allen to investigate how PEC will impact IRSR and explore methods to reallocate IRSR amongst the regions in the loop.[155] This formed part of AEMO's PEC Market Integration work leading up to the rule change request.[156]

The modelling results suggest that counter-price flows and negative IRSR will occur more frequently in the PEC loop than they do currently in the NEM. Based on ACIL Allen's results,

150 The local price is the marginal cost of electricity at a specific node (point on the network), taking into account generation, load, and constraints. Although NEM settlement uses regional prices (the same for an entire region except for marginal loss factors), NEMDE calculates local prices (ignoring the effect of losses) and uses them in dispatch.

151 There are cases where closed loops in the transmission network pass through two regions – for example the two interconnectors Heywood and Murraylink between Victoria and South Australia. However, loops crossing only two regions don't lead to larger or more frequent negative IRSR because IRSR is based on the *net flow* between the two regions. The net IRSR on the corresponding directional interconnector is usually positive, notwithstanding factors such as disorderly bidding that may cause inefficient counter-price flows. See Box 2 in section 3.1.1.

152 Intra-regional settlements residue does occur but this is a result of electrical losses rather than differences in local prices as such. Intra-regional settlements residue is not the subject of this rule change.

153 For AEMO's decision on how to represent PEC in NEMDE and its reasoning, see: AEMO, PEC Market Integration Paper, November 2022, https://aemo.com.au/en/consultations/current-and-closed-consultations/project-energy-connect-market-integration-paper, p. 12.
AEMO considered two options for reflecting the new physical transmission link in the dispatch model:
(1) the 'interconnector' or 'loop' model, where PEC is considered as a separate line linking New South Wales and South Australia for the purposes of dispatch.
(2) the 'micro-slice' model, which would insert a small piece of the Victorian region interfaced between the New South Wales and South Australian regions. This would maintain the current topology of the NEM for the purposes of dispatch. In its submission to our consultation paper, Shell Energy maintained its preference for the micro-slice implementation (submission to the consultation paper, p. 3).
See also appendix B of our consultation paper for more information on how the dispatch engine treats regions and interconnectors (the 'hub-and-spoke model').

154 A loop flow constraint (also called a 'mesh constraint') is an equality constraint that governs dispatch and flows around a loop.

155 ACIL Allen, 'Modelling the settlement effects of PEC'.

156 AEMO, PEC Market Integration Papers.

negative IRSR is expected to accrue on at least one of the three interconnectors around one-third to half of the time.[157] This is consistent with the spring washer effect.

C.4 Current arrangements for clamping

Currently, AEMO limits counter-price flows and negative IRSR by applying constraints in NEMDE. This is known as negative residue management (NRM) or clamping. To clamp an interconnector, AEMO applies a constraint in NEMDE that limits the power flow on the interconnector to zero. These clamping constraints are only turned on when needed.

AEMO uses clamping to limit negative IRSR, but not positive IRSR, because excessive negative IRSR is often the result of disorderly bidding and increases costs for consumers unnecessarily. The clamping procedure is designed to keep negative IRSR at a manageable level, but not to prevent it completely.

AEMO's intended approach to clamping in transmission loops is described in section 3.1.3 of this report.

C.4.1 Clamping is largely governed by AEMO procedures, rather than the NER

AEMO has significant discretion regarding the approach and methodology for clamping. The requirement in the NER is that the dispatch process should aim to minimise dispatch cost, 'subject to... the management of negative settlements residue' (amongst other matters).[158]AEMO develops a procedure for the management of negative settlements residue, and is required to consult on and publish this procedure as part of the network constraint formulation guidelines.[159] We refer to this as the 'clamping procedure' but in practice it is published across multiple AEMO documents.[160]

C.4.2 The current procedure clamps all interconnectors at thresholds of $100,000

In the existing clamping procedure, AEMO applies clamping constraints to a given interconnector when the cumulative negative residue on that interconnector reaches a threshold of $100,000.[161] At a high level, clamping constraints work by setting the flow on the interconnector to zero in NEMDE. AEMO removes the constraints when system conditions have changed such that negative residue is no longer likely to occur.[162] This is done on a per-incident basis rather than over any specific time period.

157 ACIL Allen, 'Modelling the settlement effects of PEC', p. 20.
Results quoted in this consultation paper are based on ACIL Allen's Stage Two: NEM Model.

158 NER clause 3.8.1(b). Strictly speaking, the dispatch process aims to maximise the value of spot market trading, rather than minimise cost, but these two objectives are equivalent except where there is scheduled load.

159 NER clause 3.8.10(c)(5).

160 See AEMO, Constraint Formulation Guidelines, p. 24; AEMO Dispatch procedure, pp. 37-38; AEMO, Automation of Negative Residue Management.

161 AEMO, Automation of Negative Residue Management.

162 AEMO Dispatch procedure, pp. 37-38.

C.5 The Commissioned has considered IRSR in previous processes

The Commission has considered how IRSR is managed and distributed in the NEM in a number of past rule changes and reviews. The SRA arrangements and the treatment of negative IRSR have changed as a result of some of these processes. Key processes included:

- The 2006 *Recovery of negative inter-regional settlements residue* rule change, which determined that negative IRSR would be deducted from the auction proceeds paid to TNSPs, rather than recovered from future auction fees paid by SRA participants.
- The AEMC's 2008 *Congestion Management Review*, which recommended that negative residue should no longer be netted off from positive residue and that the clamping threshold should be increased from $6,000 to $100,000. Both of these recommendations were implemented.
- The abolition of the Snowy NEM region in 2008 (rule change), due to problems with congestion and negative IRSR around that region.[163]
- The AEMC's 2014 *Management of Negative Inter-regional Settlements Residues* review (also known as the clamping review), which affirmed AEMO's clamping procedure.
- The 2017 *Secondary trading of settlement residue distribution units* rule change allowing SRA participants to re-offer previously purchased SRD units for sale at subsequent auctions, to improve liquidity.

163 AEMC, Abolition of Snowy Region, final determination, 30 August 2007, https://www.aemc.gov.au/rule-changes/abolition-of-snowy-region.

D Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL for the Commission to make a draft rule determination.

D.1 Draft rule determination and draft rule

In accordance with section 99 of the NEL, the Commission has made this draft rule determination for a more preferable draft rule in relation to the rule proposed by the proponent.

The Commission's reasons for making this draft rule determination and draft rule are set out in chapter 2.

A copy of the more preferable draft rule is attached to and published with this draft determination. Its key features are described in chapter 3.

D.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules.

The more preferable draft rule falls within section 34 of the NEL as it relates to sections 34(1)(a)(i) and 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 draft rule
- the rule change request
- submissions received during first round consultation
- the Commission's analysis as to the ways in which the draft rule will or is likely to contribute to the achievement of the NEO
- the application of the draft rule to the Northern Territory

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[164]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[165] The more preferable draft rule is compatible with AEMO's declared network functions because it would not affect those functions.

164 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.

165 Section 91(8) of the NEL.

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.[166] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

As the more preferable draft 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:[167]

1. the national electricity system
2. one or more, or all, of the local electricity systems[168]
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.[169] 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.[170]

In developing the draft rule, the Commission has considered the application 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 this rule will apply in the Northern Territory (even though it will have no practical effect).
- Should the rule be different in the Northern Territory? No. The Commission's draft rule is a uniform rule because the Commission does not consider it appropriate for the draft rule to be different in the Northern Territory.

166 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016.

167 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

168 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

169 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

170 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.

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 draft 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 proposed amendments made by the more preferable draft rule be classified as civil penalty provisions or conduct provisions.

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
CPT	Cumulative price threshold
CVP	Constraint violation penalty
DNSP	Distribution network service providers
ENA	Energy Networks Australia
IRSR	Inter-regional settlements residue
JEC	Justice and Equity Centre
ME-	Metered consumed energy
MPC	Market price cap
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
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
PEC	Project EnergyConnect Stage 2
Proponent	The individual / organisation who submitted the rule change request to the Commission
QED	Quarterly Energy Dynamics
RRP	Regional reference price
SRA	Settlements residue auction
SRD	Settlements residue distribution
SRC	Settlement residue committee
TNSP	Transmission network service provider
TRD	Total regional demand
TUOS	Transmission use of service