Andrew MEARS

PO Box 10, Toronto, NSW
2283 Australia

2nd September 2026

Ms Anna Collyer
Chair
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000
Lodged electronically

Dear Ms Collyer,

Review of the Integrated System Plan framework — Discussion paper (EPR0092)

Thank you for the opportunity to respond to the discussion paper. I make this submission as an individual, and my motivation comes from two decades of building the systems this Review is now trying to plan for. I am an electrical engineer and clean tech entrepreneur, including founder and former CEO of SwitchDin. I led the development of SwitchDin's distributed energy orchestration platform used by networks, retailers and aggregators to control consumer energy resources (CER) at scale, including SA Power Networks' Flexible Exports program, where dynamic operating envelopes first moved from concept to a live connection standard, and Western Australia's Project Symphony, where SwitchDin's platform orchestrated customer assets into a simulated wholesale and network services market. That work, in Australia and internationally, has given me a practical view of what distribution system operation, aggregation and consumer participation require: standard data, interoperable control, transparent network limits and a planning framework that treats consumers' assets as resources rather than as load to be forecast. I have read the 22 published submissions and have written this submission to present my own case and also to draw other submissions together rather than repeat them.

My central point is simple. **The Commission's initial preference for Strawperson 3 is right, but SP3 as drafted widens the plan without giving the demand side an owner, a dataset or a delivery route.** The Commission identifies this gap itself when it notes that under SP3 the non-transmission elements depend on the ISP being 'trusted and used as an authoritative reference point' by parties outside the actionability framework.[1] That trust cannot be assumed; it must be built into the framework. Each section below leads with the recommendation, then the reasoning, keyed to the discussion paper's questions.

Key recommendations

1. **Adopt SP3 and amend the ISP purpose** to a whole-of-system plan for the national electricity system meeting the needs of consumers at least cost, with co-optimisation staged over the 2028 and 2030 ISPs.
2. **Build the wider plan bottom-up:** DNSPs, in their DSO planning function, to produce NEM-consistent forecasts and option sets and to become joint-planning parties with defined minimum inputs.
3. **Standardise the demand-side data layer** (hosting capacity, operating-envelope headroom, flexibility availability) and establish independent asset registration and market facilitation.
4. **Fix the option set** so that distribution, sub-transmission and flexibility portfolios are screened on like-for-like criteria with published thresholds.
5. **Make the ISP consumer-facing:** bill impacts, a retrospective report, open modelling, the Consumer Panel reporting on the draft IASR with technical support, and demand-side engagement beyond DNSPs.
6. **Make designation fit for purpose:** a flexibility-first test before actionable designation, re-opener triggers, an enduring cost and schedule register, and a path to actionable distribution solutions.
7. **Return community engagement and timely-delivery incentives to scope, and define the screening-versus-funding handover to the Electricity Network Regulation Review on non-network options.**

[1] AEMC, *Review of the integrated system plan framework: Discussion paper* (EPR0092), 23 July 2026, p. 33. Submissions cited below are the published submissions to the AEMC consultation paper on EPR0092 (February–March 2026).

Scope. Each recommendation sits within the Terms of Reference, which cover rules 5.16A, 5.22 and 5.23 of the NER and other rules or AER guidelines where directly relevant, and which ask for recommended NER changes, actions for regulatory agencies and market operators, advice on the ISP's interaction with jurisdictional frameworks and implementation pathways.[2] Recommendations 1, 4, 5 and 6 go to clauses 5.22.2, 5.22.6, 5.22.7 and 5.16A and to the AER's Cost Benefit Analysis and Forecasting Best Practice Guidelines. Recommendation 2 relies on the joint planning provisions in clause 5.14.4, which the discussion paper itself takes up in section 5.3.3, and does not reopen the Distribution Network Development Plan rule; it asks only that DNDP outputs be aligned to ISP scenarios and carried into the ISP. Recommendation 3 is in part a matter for the Review (data standards under the AER guidelines) and in part advice the Commission is asked to give to DCCEEW and the ECMC on the CER Taskforce's DSO policy design and the Demand-side Statement of Opportunities; I flag that distinction rather than assume it away. Recommendation 7 asks the Commission to revisit its own section 5.4 prioritisation, which Question 10.1 invites.

Objective 1. Widen the plan, and build it bottom-up (Q3, Q4, Q5.3, Q7, Q9.3)

Recommendation 1.	**Adopt SP3 and amend the purpose (Q4.1–4.2).** Recast clause 5.22.2 as a whole-of-system plan for the *national electricity system* meeting the *needs of consumers* at least cost,[3] and stage the extension of decision variables to distribution, CER and demand-side resources over the 2028 and 2030 ISPs.
Recommendation 2.	**Build the wider plan bottom-up (Q5.3c, Q9.3).** Require DNSPs to produce NEM-consistent, scenario-aligned bottom-up forecasts and option sets for their networks,[4] and make DNSPs, in their DSO planning function, joint-planning parties under clause 5.14.4 with defined minimum inputs.
Recommendation 3.	**Standardise the demand-side data layer (Q7.3, Q9.3).** Set NEM-wide standards for hosting capacity, operating-envelope headroom and flexibility availability, and establish an independent asset-registration and market-facilitation function so AEMO and DSOs have CER visibility without operating distribution markets.
Recommendation 4.	**Fix the option set (Q7.1, Q10.1).** Require the ISP and Electricity Network Options Report to include distribution, sub-transmission and flexibility portfolios screened on like-for-like criteria, with thresholds published.[5]

The Commission records that JEC, ECA, EEC, Ausgrid, Essential Energy and SAPN all consider the ISP still functions as a transmission plan.[6] The Consumer Panel calls the 2026 ISP 'an inflection point'.[7] Against this, ENA, AEMO, Energy Australia and Hydro Tasmania counsel restraint, chiefly on grounds of modelling burden and investor uncertainty.[8] Read together, the two camps are not as far apart as they appear: the objection is to *AEMO* modelling the distribution system in ever greater depth, not to the distribution system being planned. Ausgrid's proposal that DNSPs model their own networks to AEMO's scenarios dissolves most of the objection, and ENA's own analysis, cited by SAPN,[9] puts the prize at more than $7 billion a year and up to five years of transmission de-risking, which explains why it is worth doing. The Commission's own reference to Great Britain, where the national plan, Regional Energy Strategic Plans and DNO-held DSO functions operate as 'interlinked

[2] AEMC, *Terms of Reference: Integrated System Plan (ISP) Review*, 9 October 2025, pp. 3–4.

[3] Justice and Equity Centre, submission to the consultation paper, pp. 6–7. Energy Consumers Australia, submission to the consultation paper, pp. 5–6.

[4] Ausgrid, submission to the consultation paper, pp. 2–4.

[5] Essential Energy, submission to the consultation paper, pp. 2–4. Nexa Advisory, submission to the consultation paper, p. 8.

[6] AEMC, *Discussion paper* (EPR0092), 23 July 2026, p. 25.

[7] ISP Consumer Panel, submission to the consultation paper, p. 1.

[8] Energy Networks Australia, submission to the consultation paper, pp. 1–5. AEMO, submission to the consultation paper, p. 2.

[9] SA Power Networks, submission to the consultation paper, p. 1.

but separate processes',[10] is the architecture I recommend: a top-down ISP calibrated by mandatory bottom-up distribution plans, not a single enlarged model.

What none of the submissions supply, and what SP3 lacks, is the party accountable for the non-transmission half of the plan. I understand that Britain answered this in 2023/4 by keeping DSO functions with the DNOs, creating regional strategic planners under the system operator and appointing Elexon as independent Market Facilitator to run a common asset register (FMAR, due 2027).[11] Its ED3 framework then made 'build and flex' the default: reinforcement is approved only after flexibility has been tested with a common evaluation tool.[12]

The Australian evidence points the same way: Project Symphony (an interest I declare, as above) showed that value was positive only when network and market services were stacked, that a DER data hub, common service standards and dynamic connections are prerequisites, and that operating-envelope compliance of around 50 to 66% is the risk a wider plan must model rather than assume.[13] Australia has the components, the Demand Side Factors Statement, the new Distribution Network Development Plans, the forthcoming DSOO and the CER Taskforce's advice (that DNSPs be formalised as DSOs),[14] but no rule joins them to the ISP. Recommendations 2 and 3 make that join. The Review's foundations say planning roles will not be reallocated;[15] they do not prevent the Commission defining who is a joint-planning party and what they must provide. Recommendation 4 addresses where non-network options fail, which is screening: 500 MW thresholds and export-only metrics exclude medium-scale portfolios before any cost-benefit test is run.[16]

Objective 2. Make the ISP consumer-facing (Q9.1, Q9.2)

Recommendation 5.	**Make the ISP consumer-facing (Q9.1–9.2).** Require a bill-of-the-future and jurisdictional bill impacts, a retrospective report each cycle and replicable open modelling;[17] have the Consumer Panel report on the draft IASR with independent technical support; and require demand-side engagement that goes beyond DNSPs as proxies.[18]

Every consumer submission, and several industry ones, asks for the same things: open and replicable modelling,[19] disclosure of judgement calls,[20] a retrospective reconciling successive ISPs, and outputs consumers can read, including bill impacts by jurisdiction.[21] I endorse them and add one point from practice. The information asymmetry the ISP was created to reduce[22] is now largest at the distribution level, where third-party CER and flexibility providers cannot see hosting capacity, export limits or the network's own option costs, and so cannot offer alternatives. Ausgrid's evidence that AEMO's data template 'was not sufficiently stress-tested' and produced inconsistent hosting-capacity data across DNSPs[23] shows that voluntary provision will not close this gap. A NEM-wide

[10] AEMC, *Discussion paper* (EPR0092), 23 July 2026, pp. 33, 43.

[11] Ofgem, *Decision on future of local energy institutions and governance*, 15 November 2023; Ofgem, *Flexibility digital infrastructure: Strategic direction setting*, open letter, 4 November 2025.

[12] Ofgem, *Ofgem sets rules for 2028 to 2033 grid investment to meet growing electricity demand*, press release, 2026; Energy Networks Association, *Flexibility services*, n.d.

[13] Western Power, *Project Symphony: Pilot results and recommendations*, ARENA, 2024.

[14] Nexa Advisory, submission to the consultation paper, p. 9.

[15] AEMC, *Discussion paper* (EPR0092), 23 July 2026, p. 22.

[16] Essential Energy, submission to the consultation paper, pp. 2–4.

[17] Energy Consumers Australia, submission to the consultation paper, pp. 4–8. Tasmanian Small Business Council, submission to the consultation paper, pp. 7–8.

[18] ISP Consumer Panel, submission to the consultation paper, pp. 2, 4.

[19] Energy Consumers Australia, submission to the consultation paper, pp. 7–8. Nexa Advisory, submission to the consultation paper, pp. 1–2.

[20] Energy Australia, submission to the consultation paper, p. 3.

[21] Tasmanian Small Business Council, submission to the consultation paper, p. 7. Justice and Equity Centre, submission to the consultation paper, p. 8.

[22] AEMC, *Discussion paper* (EPR0092), 23 July 2026, p. 9.

[23] Ausgrid, submission to the consultation paper, p. 3.

minimum distribution dataset, published on a cycle investors can act on, is the most valuable transparency reform available to this Review and is what makes recommendation 1 modellable.

On governance, AEMO and the Consumer Panel already agree the Panel should report on the draft rather than the final IASR;[24] ECA's independent technical panel and TSBC's small-business membership should be adopted with it.[25] The Panel's observation that AEMO 'uses distribution as a proxy for the demand side'[26] is the governance gap that matters most for a wider plan: joint planning must reach aggregators, community energy and flexibility providers, not only network businesses.

Objective 3. Make designation fit for purpose (Q3.3, Q5.4, Q8)

Recommendation 6.	**Make designation fit for purpose (Q3.3, Q5.4, Q8.2).** Retain the ISP–RIT-T link but require a flexibility-first test before transmission is designated actionable, define re-opener triggers on material cost or timing change, publish an enduring cost and schedule register,[27] and open a path to actionable distribution solutions with cost allocation resolved.[28]

ENA argues the RIT-T is no longer on the critical path;[29] Nexa, the AEC and RWE say it delivers plans, not projects; TSBC and CIS argue designation has become a de facto commitment made before robust testing;[30] PIA would remove the designation power altogether.[31] The Commission should hold the link between the ISP and project assessment[32] but change what designation means.

Three changes follow. First, a flexibility-first test, before any transmission project is designated actionable, so that the portfolios of distribution, storage and demand-side options (such as) Essential Energy shows can be delivered in three to four years[33] are tested before seven-to-eight-year greenfield lines are locked in. Second, re-opener triggers on material cost or timing change, as Energy Australia and TSBC propose,[34] paired with an enduring cost and schedule register so the trigger is observable. Third, a defined path for actionable distribution solutions with cost allocation settled where benefits accrue beyond the local customer base, which is SP4's element that SP3 should borrow. Designation would then hold networks to the plan and the plan to its own least-cost claim. Western Australia shows the alternative: its Whole of System Plan is advisory and delivery runs through a state-owned network with direct appropriation, as when the 2023 SWIS Demand Assessment led straight to $126 million of funded Stage 1 planning;[35] the NEM's privately owned networks and jurisdictional frameworks cannot replicate that, so the choice here is between designation made fit for purpose and no effective national delivery route at all.

---

[24] AEMO, submission to the consultation paper, p. 6. ISP Consumer Panel, submission to the consultation paper, p. 7.

[25] Energy Consumers Australia, submission to the consultation paper, p. 4. Tasmanian Small Business Council, submission to the consultation paper, p. 8.

[26] ISP Consumer Panel, submission to the consultation paper, p. 2.

[27] Nexa Advisory, submission to the consultation paper, p. 6.

[28] Essential Energy, submission to the consultation paper, p. 3.

[29] Energy Networks Australia, submission to the consultation paper, pp. 8–9.

[30] Tasmanian Small Business Council, submission to the consultation paper, p. 6. Centre for Independent Studies, submission to the consultation paper, pp. 21–22.

[31] Policy Institute Australia, submission to the consultation paper, p. 1.

[32] AEMC, *Discussion paper* (EPR0092), 23 July 2026, p. 27.

[33] Essential Energy, submission to the consultation paper, pp. 5.

[34] Energy Australia, submission to the consultation paper, p. 2. Tasmanian Small Business Council, submission to the consultation paper, p. 6.

[35] Government of Western Australia, *SWIS Demand Assessment 2023 to 2042*, 2023.

Objective 4. Revisit the section 5.4 exclusions (Q10.1)

Recommendation 7.	**Return two exclusions to scope and define the handover on the third (Q10.1).** **(a) Non-network option incentives.** Retain the funding question with the Electricity Network Regulation Review (ENRR) but bring option-set screening back into this Review and require the Commission to state in its draft report which aspects of non-network option treatment it is handing to the ENRR, and on what timing. Screening determines whether an option is ever assessed; the revenue framework determines only how it is paid for once chosen. Deferring both to the ENRR leaves neither review accountable for the first. **(b) Community engagement.** Return to scope. It is inseparable from the transparency and trust issues the Commission retains in section 5.3, and Essential Energy's proposed community impact index demonstrates that it can be made concrete and comparable rather than treated as a qualitative overlay. **(c) Timely-delivery incentives.** Return to scope. The TPIR found no evidence that the framework causes delay, but that analysis pre-dates the 2023 amendment adding jurisdictional emissions reduction targets to the NEO. The cost of delay it weighed therefore excluded forgone emissions reduction, which now forms part of the long-term interests of consumers the Commission must assess against.

Section 5.4 defers non-network option incentives to the ENRR, community engagement to recent reforms, and delivery incentives to the TPIR's finding of no evidence that the framework causes delay.[36] Each reason is weaker than it looks, and the first is answered by the Commission's own regulator. The Demand Management Incentive Scheme was designed precisely to overcome the capex bias, offering distributors a financial incentive of up to 50 per cent of the efficient costs of demand management projects, subject to a net benefit constraint and an overall cap of 1 per cent of allowed revenue in any year.[37] On introducing it, the AER estimated that full subscription could realise up to $1 billion of demand management investment over five years.[38] Subscription has not approached that scale: in its most recent published assessment (to my knowledge), covering the 2020–21 and 2021–22 reporting years, the AER approved $594,590 in incentive payments across Ausgrid, AusNet Services and United Energy.[39] The constraint is evidently not the size of the reward. It is that a distribution, storage or flexibility portfolio which never enters the ISP or RIT-T option set generates no incentive to earn, however generous the scheme. The ENRR can determine how a non-network option is funded once it has been identified; it cannot make one appear in an option set from which it was excluded by a 500 MW threshold, and screening sits squarely within this Review's Terms of Reference.

Community engagement is inseparable from the transparency and trust issues the Commission keeps in section 5.3, and Essential Energy's community-impact index shows it can be made concrete.[40]

The TPIR analysis pre-dates the 2023 amendment adding emissions targets to the NEO, so the cost of delay it weighed did not include forgone emissions reduction.

I would welcome the opportunity to discuss these points with the project team and am happy for this submission to be published.

Yours sincerely,

Andrew Mears, PhD
andrew@majorityworld.com.au

[36] AEMC, Discussion paper (EPR0092), 23 July 2026, pp. 67–71.

[37] Australian Energy Regulator, Demand management incentive scheme (DMIS) assessment 2020–21 and 2021–22.

[38] Australian Energy Regulator, AER incentive scheme to drive potential $1bn in demand management action, news release.

[39] Australian Energy Regulator, AER releases outcome of Demand Management Incentive Scheme for 2020–21 and 2021–22 reporting years, 18 May 2023.

[40] Essential Energy, submission to the consultation paper, pp. 5–6.