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Australian Energy Market Commission  
Level 15, 60 Castlereagh Street  
Sydney NSW 2000

Submitted via website: [www.aemc.gov.au](http://www.aemc.gov.au)

## **National Electricity Amendment (Integrated Distribution System Planning) Rule 2026 — directions paper (Ref. ERC0410)**

CitiPower, Powercor and United Energy (**the networks**) welcome the opportunity to respond to the Australian Energy Market Commission (**AEMC**) directions paper on the National Electricity Amendment (Integrated Distribution System Planning) Rule 2026 proposed by Energy Consumers Australia (**ECA**).

From the Directions Paper the AEMC believes that a 20-year forecast of network wide future augmentation down to the low voltage (**LV**) network level will better assist consumer energy resources (**CER**) in deciding where to locate. Implementation of this approach is through modification of the Distribution Annual Planning Report (**DAPR**) to a short-term plan published annually and establishment of an Integrated Distribution System Plan (**IDSP**) to be refreshed every 5 years.

Whilst we support the intent of the reform, in its current form, we believe it will fail to achieve its objective and will increase costs on distributors and customers.

### **Forecasting and planning for small populations is complex**

Whilst broad area planning of transmission and sub-transmission networks serving large groups of customers is complex, it can produce credible results because the individual variations in forecast assumptions tend to cancel out when aggregated across a larger population. While there will be fluctuations or outliers, such as uptake of electric vehicles (**EV**) per customer, the larger sample reduces the impact of such outliers allowing robust trend analysis with greater statistical confidence. The proposal appears to suggest that distributors can apply the same methodology that AEMO use in its ISP at the LV level to achieve a 20-year forecast for augmentation network wide. Producing a credible forecast for the LV network is not only an order of magnitude increase in workload and complexity but, forecasting LV over long periods is extremely challenging given that individual variations with small populations quickly compound making forecasts unstable. Meaningful LV augmentation forecasts are not practical or credible over 20 years.

### **Forecasting horizons should reflect level of confidence**

We support the need for, and benefit of, publishing longer term forecasts and network strategies to foster alignment between transmission and distribution development. Although we urge consideration to be given to the time horizons mandated. With transmission, longer term forecasts, like the ISPs 20 years, are practical and feasible. This time horizon becomes increasingly challenging moving down through a network hierarchy and, at the LV level specifically, even a 2–5-year forecast range is challenging. The practicality and confidence in 20-year LV forecasts would be poor. In contrast, confidence in forecasts at the sub-transmission or zone substation levels over 20 years would be high. Accordingly more consideration needs to be given to credible time horizons for forecasts with LV, if included at all, being limited to more realistic timeframes and potentially at an aggregate level.

The United Kingdom adopted a default planning horizon of 10 years and only down to the high voltage (**HV**) level. Distributors then provide forecasts and network plans annually for years 1-10, supplementing this with longer term 'strategic forecasts' on 5 yearly increments (i.e. years 15, 20 and 25). This approach would work well

in Australia for the sub-transmission and HV network, balancing workload for distributors whilst providing robust information for interested stakeholders.

### Alignment with regulatory process

We support creating stronger links between the planning process and the regulatory reset process. Although the proposal as made for Option 1 would exacerbate the tight timeframes between the creation of forecasts and the submission deadlines for a Victorian regulatory cycle. Key inputs into an IDSP forecast and network planning assessment process include the Australian Energy Market Operator's (AEMO) Inputs, Assumption and Scenarios Report (IASR) and Integrated System Plan (ISP) and the Australian Energy Regulators (AER) Values of Customer Reliability (VCR). Updates to the IASR and ISP came less than 5 months before submission of our latest regulatory proposal creating significant time pressure to its completion. Had these forecasts been materially different to previous years, and had we been required to create network plans for multiple scenarios, this workload may not have been practical forcing us to rely on older forecasts.

If the IDSP is to have a role, its timing must be aligned with preparation of the regulatory proposal and the scenarios and assumptions that underpin it.

### Non-network alternatives

The current DAPR takes several months to produce and is the culmination of an ongoing annual planning and assessment process. The requirements of DAPR also only focus on material, large scale constraints down to the HV level and, once a network constraint is published in the 5-year window, we must have augmentation plans established to mitigate any impact upon customers while seeking non-network alternatives. We recognise that this level of constraint is challenging for CER to address without multiple parties acting to provide the non-network service.

Over recent years we have been actively working to build the non-network service market through mechanisms outside of the DAPR by advertising constraints outside of the DAPRs fixed annual schedule. For example, LV constraints more suitable to being addressed with CER are often recognised following summer peak demand when demand growth becomes evident. In these cases augmentation has potential to be deferred with CER if it is available in the area, but the constraint needs to be addressed in a short timeframe such as before the next summer. Only through a system whereby network constraints are published more dynamically can CER be attracted in a timely manner. That is why we have used the Piclo Flex platform to attract non-network alternatives for constraints of all kinds, from small scale at LV to large scale at HV. The IDSP proposal does not address this issue, nor does it address the challenge of building non-network capability for larger scale constraints that may emerge beyond the 5-year regulatory period. This is often mis-understood by non-network proponents who expect long term revenue streams from deferral of long-term capital expenditure that DNSPs are not funded for.

### State based requirements

Victoria has a separate requirement under the *Electricity Distribution Code of Practice (EDCoP)* to produce DAPRs. There has been no proposal to remove these EDCoP requirement hence it is difficult to envisage that the proposed reforms will result in any savings for Victorians through efficiency improvements or reductions in DAPR scopes under any policy option.

Given the above, we support an augmented version of policy option 2 to deliver benefits in the near term. The DAPR can be elevated to be a more strategically based document, and its annual nature allows it to be more current and robust than a 5 yearly IDSP. Strategic planning should not however be seen as a panacea for growing the market for non-network solutions. It should not also be confused with publication of network data or improvements in consistency of forecasting approach by distributors. These are separate issues best resolved through other market or rules reforms that should be consulted on holistically.

Responses to the specific questions raised in the Directions Paper have been provided in the Appendix to this letter. Should you have any queries, please contact Bea Cleeve on 0409 805 058 or [bcleeve@powercor.com.au](mailto:bcleeve@powercor.com.au).

Yours sincerely

A handwritten signature in black ink, appearing to read 'L. Fetherston', with a stylized flourish at the end.

Lauren Fetherston  
**Head of Regulatory Policy & Compliance**  
**CitiPower, Powercor and United Energy**

## Appendix 1

### 1. Does the purpose of the proposed strategic planning process in policy option 1 need to be outlined in the rules?

We support the continued evolution of the network planning process to meet both customer needs and the changing energy landscape. The increasingly bi-directional and dynamic nature of distribution networks, the growing penetration of CER and the anticipated rise in large, grid-connected loads such as data centres, all present challenges and opportunities for more holistic system planning. Reviewing policy option 1, we are not convinced it meets the objective of furthering the value of CER, streamlining the network planning process or making network planning more engaging and efficient.

Neither the proposed IDSP, or DAPR process, is sufficiently timely to effectively incentivise CER to address network constraints. This is better achieved through more customer focused and market-based systems such as Piclo Flex that use more granular data, updated as needs arise rather than on an annual process.

For Victorian distributors, option 1 will further increase workload. The EDCoP requires networks to prepare DAPRs annually and with specific reporting requirements on reliability, asset replacement, CBD security of supply and bushfire mitigation. This doesn't change if the proposed rule is passed forcing duplicate reporting or mismatched reporting to other states

Policy option 1 does not recognise the additional complexity and uncertainty involved network planning down to LV. It is not at this stage credible to place a 20-year planning horizon on LV networks, especially with the variability in scenarios and assumptions that are associated with transmission planning undertaken by AEMO.

### 2. Would a 20-year planning horizon most effectively support DNSPs to strategically plan their networks?

Our networks already undertake a strategic planning process. This process underscores our investment decisions and is a core input to our regulatory proposals. Its acknowledged this may not always be readily apparent to stakeholders. Consequently, we support making strategic planning more transparent to stakeholders.

Network planning at the distribution level, and particularly at the customer interface on LV networks, is extremely challenging. This is due to constantly evolving technologies, the fast pace of change and complexity of predicting consumer behaviour at the local level over any duration. The task is made more challenging by changing State and local government plans and priorities which offer little to no insights into actual timing of developments. This makes the task of applying a common forecasting horizon to all elements of the distribution network impractical.

At a transmission connection, sub-transmission, and the zone substation level, provision of robust forecasts in the range of 10-20 years is practical and feasible. However this becomes increasingly challenging moving from the HV feeder level to the distribution substation and LV network level. When moving down through a network hierarchy the challenge of forecasting smaller populations becomes more significant and with a credible forecast more in the 2–5-year range rather than 20 years. There is a strong emphasis in the Directions Paper on customer energy resources (**CER**) assumptions informing LV forecasts. While they are important, they are not the only inputs to a credible forecast and network planning. The need to augment on existing LV networks is primarily driven by changes in existing customer behaviours which can be highly variable with many change drivers, and impact LV forecasts just as much as CER assumptions.

The Directions Paper bemoans the lack of publicly available LV data with examples such as LV circuit power flows and power quality data given. Victorian distributors can, and do, provide this data to customers yet this data is only representative of history and is not a long-term forecast. Providing forecast data, even for a 5-year horizon, that mirrors historical data is not practical or credible and will incur significant costs and systems investment to enable its access.

### **3. Is scenario analysis the most effective approach for addressing uncertainty in a long term planning horizon?**

Scenario analysis is a prudent and robust approach to managing uncertainty. It's a process we already apply today. We are supportive of the Directions Paper proposal that distributors be permitted to vary scenarios specified by the AER provided those variations are made transparently.

The volume of scenarios chosen will create additional work for distributors. While our forecasting processes create scenarios that utilise AEMO IASRs as a starting point for Step Change, Progressive Change, and Green Energy Exports forecasts, we only undertake analysis on our bottom up built Step Change forecast. Other forecasts are used for sensitivities only. If distributors are required to undertake network analysis and create network plans for multiple scenarios, this will multiply the time and resources required by distributors with no credible or material benefit for stakeholders.

### **4. Does the IASR provide the right baseline inputs for proposed strategic planning process under option 1?**

We use the IASR as foundational input to our forecasting today, although only to represent the starting point for our own processes and analysis.

IASR assumptions and scenarios are not sufficiently detailed to support network planning in isolation. They must be supplemented with local knowledge, socio-demographic data and network information to ensure that the forecasts that are produced, and any analysis they inform, credibly represent the real-world network and customer behaviour.

Therefore, we are supportive of aligning to use the IASR, provided there is the ability to transparently add or vary assumptions to customise them to our networks.

### **5. Should the proposed strategic planning process be linked to the regulatory proposal process in Chapter 6 of the NER under policy option 1?**

We support the planning process being linked to the regulatory reset process. There are synergies, especially when considering stakeholder engagement, and an opportunity to more closely tie the planning process with the remuneration process.

There are however timing issues with aligning the Victorian regulatory cycles with the proposed IDSP. AEMO's IASR and ISP and the AER's VCR refreshes are not aligned with the preparation of Victorian regulatory proposals. This lack of alignment creates risk that the assumptions and scenarios on which the IDSP would be based will be at least 12 months out of date come preparation of the regulatory proposal. An example of where this impact can be substantive is for example where our initial regulatory proposal for the 2026-31 regulatory period was due on the 31<sup>st</sup> January 2025. AEMO's last material IASR update came on the 29<sup>th</sup> August 2024 giving less than five months to not only develop an entirely new bottom up forecast, but then also assess all impacted projects and portfolios under this new forecast. We were able to integrate the 2024 IASR update into our regulatory proposal, as the changes to scenarios and uptakes were minimal and only assessed against our Step Change forecast. If changes in IASR's were significant, or there was a mandate to assess against multiple forecasts scenarios the this would not have been practical without significant uplift in resources. This also came at the same time as the AER's VCR refresh, where new VCRs were published on the 18<sup>th</sup> December 2024 that we were unable to integrate into our draft proposal.

There is not a simple solution to this issue. Whilst there are benefits to aligning and IDSP with the publication of the regulatory proposal, this will always come with compromise. There should be an expectation that distributors use the best available information at the time of preparing any IDSP noting that this may not always be the most up to date IASR, ISP or VCR.

## 6. Does the distribution annual planning process require an explicit purpose in the rules under policy option 1?

We agree having a clearly articulated purpose statement within the National Electricity Rules would be beneficial especially as expectations change. It should still be noted the benefit to Victorian distributors will be more limited given our jurisdictional obligations.

## 7. Does the distribution annual planning report need to be streamlined under our proposed policy option 1?

We support a more efficient DAPR process. Multiple changes to the underlying rules and templates over 2012, 2016 and 2017 have greatly increased both the scope and detail required to produce a complying DAPR. This has increased the time and resources required to prepare it, but has not appreciably increased the usefulness, readership or ultimately the non-network involvement on our networks.

The Direction's Paper proposes to streamline the DAPR process through introduction of standardised formats and structures and removal of requirements to publish network data. We endorse these changes, provided the revised structure/formats provide sufficient flexibility such as that afforded to regulatory investments test. The Direction's Paper foreshadows a new forecasting guideline which we also support, provided its focus is on meeting the more granular needs of distribution networks, as the ISP methodology does not meet the needs of our network planning processes today.

Further, the Direction's Paper suggests distributor inputs into the ISP process will be improved by AEMO's on-going implementation of the *Improving consideration of the demand-side factors in the ISP* final rule (**final rule**). The final rule is only focussed on CER and only to a limited capacity using generic integration costs. It ignores other present or potential capacity in distribution networks such as embedded generation and only considers our planned regulatory expenditure. We agree that our planning processes need to integrate better with those of AEMO, but it does not mean mandating adoption of AEMO positions. Distribution planning requires far more detailed and granular analysis, and this can only be performed by distributors. Where reconciliation is required, the planning process needs to be a 2-way inclusive process that considers both the similarities and differences between different distribution networks. This unfortunately has not been our experience with AEMO.

## 8. Does network data need to be subject to a separate reporting from the DAPR?

Yes, we agree there needs to be a separate network data reporting requirement as the scope and focus of data being requested is expanding rapidly. Recent commentary conflates provision of 'network data' on existing assets, with results of detailed analysis, and projections into the future that may not be part of current business processes.

Our customers and communities have voiced concern that network data should not be produced for the benefit of other stakeholders such as retailers and aggregators at their cost. Through our engagement process we were told that network data should only be published if it can be demonstrably shown the benefits exceed the costs for **our** customers. If other stakeholders can demonstrate compelling benefits case, and are willing to pay for that data, then this network data should be made available as part of alternate control service charge.

In the previous submission, we highlighted the concept of a data or digitalisation strategy (**strategies**) that United Kingdom distributors publish and submit to Ofgem. These strategies are subject to extensive engagement with customers and stakeholders **of that distributor** including detailed cost benefit analysis by customer segment. We continue to support this approach in preference to the AER being tasked with developing a guideline. Tasking the AER with developing a guideline ignores the needs and preferences of customers and communities and will result in a generic approach that meets no one's needs.

The Directions Paper provides minimal consideration to maintaining the quality of data, specifically highly dynamic LV network data, or the liability issues associated with stakeholder reliance on this data. Whilst network

data down to the LV level can be used, it must be recognised that its quality is not perfect, and it may take several years before it is sufficiently robust to fully inform decision making. Use of network data also requires significant engineering knowledge and experience of the networks and our standards, something other stakeholders will not always have. Our experience has been that interpretation of network data is difficult for many stakeholders resulting in them returning to us to request assistance.

Improving data quality and governance, alongside supporting stakeholders in using that data is not something we have previously been funded for. This contrasts with international approaches that have internationally made digitalisation a priority for distributors. If data is to be of value, consideration is required not only to how data can become available, but also how its quality can be assured, and what assistance is needed to maximise its benefits.

**9. Do you agree our proposed policy 1 would be best implemented over 7 years?**

We support of a transition period regardless of the preferred policy option as this allows for ongoing consultation and integration of learnings as we progress.

**10. Can the current distribution annual planning process be reformed to effectively deliver strategic planning and transparency?**

Yes, we believe so and prefer this policy option to others. The DAPR process is not broken and can be amended to provide a more strategic approach that aligns with stakeholder needs and integrate more fully with the regulatory process.

**11. Have all the advantages and disadvantages of reforming the existing distribution annual planning process under policy option 2 been explored?**

As discussed earlier, the Direction's Paper places heavy weight on planning reforms to meet its objectives. We consider these objectives are better achieved through alternate solutions.

The availability of network data is better achieved through a transparent engagement process with customers and stakeholders who will be asked to fund the provision and maintenance of this data. They should also be given the opportunity to consider the benefits that are provided by that data including the benefits to them. We do not believe this should be determined by regulators or government. As referred to previously, we support the concept of a digitalisation plan.

In terms of non-network participation, a better focus would be on the application of market-based tools that can provide visibility of network constraints in a more user-friendly manner. We also believe further consideration is required on the operation of the service target performance incentive scheme (**STPIS**) and how it applies to non-network alternatives, treatment of agreements with non-network proponents that span multiple regulatory periods and greater standardisation of contract terms and conditions.

**12. Do you agree with our relative assessment of policy option 2 against policy option 1**

We do not believe policy option 1 achieves the policy objective of enhancing the role of CER in meeting network constraints, aligning planning more closely with the regulatory cycle or making network data more available. Further, it will increase costs for Victorian distributors with no discernible benefit for customers.

**13. Have all the advantages and disadvantages of replacing the existing DAPR with IDSP under policy option 3 been identified**

Please see previous comments.

**14. Do you agree with our relative assessment of policy option 3 against policy option 1**

Please see previous comments.

**15. Would our proposed options create a best practice process for strategic network planning?**

Please see our previous comments.

**16. Would our proposed policy options be consistent with the broader work programs underway?**

Given our networks are currently engaged in a regulatory reset, we remain concerned that whilst the AEMC and other stakeholders are working hard to reform energy markets to accommodate the energy transition and promote the integration of CER, this is not being reflected in AER decisions. Recent decisions demonstrate that the needs and preferences of customers and communities are being ignored. They have also failed to recognise that changes of the type proposed in this rule change e.g. network data requires investment.

We believe dedicated consideration is required for network data provision outside of this rule change. It needs to start with consideration of what data is needed by customers of each network, rather than generic assumptions or the needs of 'vested' industry stakeholders. This was achieved in the United Kingdom through individual digitalisation plans submitted by each distributor to Ofgem. Not only did this process clearly identify the network data that met the needs and preferences of customers and communities, it ensured data was appropriately governed and maintained through allowances provided by the regulator.

Beyond network data, we believe further consideration needs to be given to market based options such as Piclo Flex, if the intent is to develop a market for CER solutions to meet network constraints. Whilst the market remains relatively illiquid and nascent, there are options that could be considered to provide certainty for both networks and non-network providers to grow the market. These include options such as STPIS holidays, regulatory recognition of contract terms (and conditions), standardisation of agreements, over procurement and the broader incentive framework.