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17 April 2009
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Australian Energy Market Commission – Review of the National Framework for Electricity Distribution Network Planning & Expansion

This submission has been prepared by the Consumer Utilities Advocacy Centre Ltd (CUAC), an independent consumer advocacy organisation, established to ensure the interests of Victorian consumers, especially low-income, disadvantaged, rural, regional and indigenous consumers are effectively represented in the policy and regulatory debate on electricity, gas and water.

We commend the Australian Energy Market Commission (AEMC) on its consultation process for the scoping paper, and believe the Review of National Framework for Electricity Distribution Network Planning and Expansion (the Review) will benefit from diverse stakeholder views.

CUAC is, however, disappointed that the Terms of Reference (ToR) for the Review determined by the Ministerial Council on Energy (MCE) presuppose the solution for creating a framework for the efficient expansion of distribution networks. CUAC believes that the terms of reference constrain the AEMC to examine processes for forward planning by the Distribution Businesses (DBs), assessment of network and non-network alternatives by DBs, public reporting on full network planning information and dispute resolution.

While these issues are important, the ToR restrict the scope of the Commission's work by limiting the ability of the AEMC to ensure the policy goal of expanding distribution networks in accordance with the National Electricity Objective (NEO) is met.

Pending its consideration of issues as part of the Review, we urge the AEMC, in its capacity as policy advisor to the MCE, to seek to broaden the scope of the Review if it deems the scope restricts its capacity to conduct an effective review. In any event, the AEMC should ensure that issues brought forward as part of the Review can be dealt with through parallel or subsequent processes where possible.

In order to guide its work on this important issue, CUAC recommends the Commission seek to answer the following question as a priority: are existing or proposed network planning and expansion models compatible with the efficient provision of energy services by market participants? If not, the Commission must investigate why efficient service provision will not occur and resolve those issues identified.

Proposed Scope and Approach

In considering the NEO as part of this review, and whether the MCE's ToR are restrictive, we recommend the AEMC pay particular attention to the objective for the market to deliver efficient energy services at least cost.

Energy services* include, but are not limited to lighting, space and water heating and space cooling. In the current market, there is extremely limited energy service provision. The GridX model is the nearest business model CUAC is aware of that focuses on specifically delivering energy services while some incumbents offer limited service provision to specific consumer segments. The vast majority of market participants focus on delivering electricity, the product. This leads to sub-optimal investment throughout the energy supply chain and the requirement for policy interventions by Government authorities such as energy efficiency targets for energy retailers.

The AEMC must ensure that market design, rules and procedures facilitate efficient provision of energy services, efficient service provision being a core objective of the National Electricity Law (NEL). This requires that market participants consider and implement a full range of alternatives to network investment, including: improved efficiency of energy service provision within a network zone; distributed generation; or demand management where it is efficient.

For distribution networks to be planned for and built efficiently, mechanisms are required to overcome the dilution of investment incentive in network alternatives that arise due to split incentives related to property ownership structures (landlord/tenant) and market ownership structures (disaggregation). Improving information provision and dispute resolution are unlikely to be sufficient to address these issues.

We believe that in order to ensure networks are expanded efficiently, the AEMC should establish approximations of market benefits provided by different non-network alternatives, and allow parties implementing those technologies to capture those benefits. To do so as part of the Review, the AEMC would need to have broader ToR.

** In this paper the term energy services is used to describe the end use of energy, not the supply of energy.*

Approximations could be delivered through market rules, or other policy instruments such as feed-in tariffs, or energy efficiency rebates/programs. Most importantly, a coherent framework is required to provide long term certainty and clarity to market participants, and a comprehensive framework is required to allow multiple technologies to compete on an equal footing. This issue is discussed in more detail in response to *Question 16* – provided in the detail of this submission.

The AEMC has developed a set of criteria additional to the NEO which will guide its decision-making as part of the Review and ultimately its recommendations. We recommend the AEMC also consider the extent to which the proposed national framework enables broader policy objectives to be met in an efficient way including: the objective to reduce greenhouse gas emissions in a way that maximises benefits and minimises costs.

The remainder of the submission addresses questions posed by the AEMC in its scoping paper.

Annual Planning requirements

Q4. In addition to emerging constraints, what other types of potential problems of the distribution network should be included in annual planning reports?

Given the intent of planning reports is to encourage DBs to find efficient non-network solutions, or to allow the market to propose efficient non-network solutions, the network assets and activities reported on should include any asset or activity that could be substituted by a non-network alternative.

5. How could the interaction between transmission and distribution planning be reflected in annual planning and reporting process?

The meaning of this question is not entirely clear. Where relevant, DBs should show where proposed investments are driven by transmission related issues so that the market can see the relatedness between the two.

6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?

We believe this type of information is more likely to be useful for the regulator, as opposed to market participants.

7. What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?

For planning reports to act as a signal to the broader market to provide non-network alternatives, it is important planning reports include the following:

- the location of proposed asset building activity (specifically, the report should identify, by postcode, the areas in which a non-network alternative could substitute for the building of the network asset);
- the estimated cost of the proposed investment;
- the timing of the proposed investment;
- the time by which a non-network alternative would have to be proved firm, and implemented;
- the estimated payment a non-network alternative could attract, including the criteria a non-network alternative would have to meet to secure that value. This could include reliability, or availability criteria; and
- details of any non-network alternative already considered and reasons for its rejection.

8. For the areas that are to be reported on, what specific factors should be considered? For example for emerging constraints, how should emerging constraints be classified and how could they be consistently set out?

It would be helpful to have consistent formatting across all DBs. This would allow market participants to streamline their search for non-network alternatives.

Reports should provide a summary of opportunities for market participants to propose alternatives to network asset building. This summary could be ordered according to size, location, value, and timing. The summary should include where more detail can be found in the report.

9. Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents?

Information that is publicly available should be meaningful for the lay person, but also provide sufficient detail for more sophisticated non-network proponents to evaluate the likelihood of a non-network alternative being viable.

10. Would the Australian Energy Market Operator’s website be the appropriate central location for the planning reports to be stored and published?

It would be appropriate, but it must be understood that many lay people do not understand the role of NEMMCO, let alone that NEMMCO is being transitioned to the AEMO.

Wherever the reports are published, efforts must be made to promote the information to active market participants, and passive market participants. Passive participants could include local government, local energy/environmental action groups, or businesses that are seeking opportunities for cost effective energy reduction through energy efficiency, demand management, distributed generation or a combination of all three.

11. What would be the appropriate timeframe for the publication of the DNSP annual planning report (noting the relationship between the timeframe for the publication of the TNSP annual planning report and the DNSP/TNSP joint planning requirements)?

The meaning of this question is not entirely clear. We assume publication would be annual and would be aligned to TNSP reporting requirements.

Project Assessment and Consultation Process

12. What types of investments should be subject to the project assessment process?

CUAC believes the project assessment process should be applied to any investment type where the function could be met by a non-network alternative

13. What are the appropriate thresholds to trigger the project assessment process?

As outlined in the scoping paper, it is important that thresholds are low enough to provide a signal to non-network alternatives, and that projects can't be broken down to avoid the assessment process. We believe the NSW threshold of projects over $200,000 is probably appropriate.

However, it may be that thresholds need to be flexible depending on where the investment occurs. A $200,000 upgrade in a rural area that has 80% lower energy demand on the network than an urban area, and lower customer density, is likely to be a more significant cost for customers than the same investment in an urban area. Therefore, the threshold needs to be adaptable depending on the relative impact of a proposed network investment on the customers impacted by that investment.

We are unsure what an appropriate threshold would be precisely, but expect the AEMC to take account the relative impact of network spending, and the characteristics of the network where the investment is to occur.

14. Should the thresholds be indexed in accordance with CPI or subject to a periodic review?

The thresholds should be extended in accordance with CPI, and subject to periodic review. Emerging technologies are likely to change the landscape for non-network alternatives, and may warrant different thresholds. It is important project assessment criteria can be adapted to account for changes in market trends.

15. What factors should be considered in an RFP process and how should this be specified in the NER compared to AER guidelines? Including:

- *what defines a credible option?*

We believe there is limited value in defining a credible option. Naturally, different parties to an RFP may have different interpretations of what is a credible option. This highlights the importance of the dispute resolution process, and the capacity for the dispute resolution body to undertake detailed engineering analysis.

- *what information is needed to enable market participants to raise alternatives?*

Please refer to CUAC's response to *Question 7*. This information is best included in AER guidelines.

- *how long should the consultation take place?*

Different non-network alternatives require very different lead times. The AEMC must satisfy itself that the time it allows is sufficient for the type of non-network solutions it aims to elicit. For distributed generation projects, it is likely that more than 12 months is needed, and potentially as much as 18-20 months. For energy efficiency or demand management, projects may be developed more quickly, but may still require up to 12 months for planning and implementation.

- *should an RFP process include elements to deal with the potential issue of DNSPs seeking assurance from non-network proponents for the performance of a non-network option?*

It is reasonable that a non-network alternative be required to meet performance parameters, and the RFP should define those parameters. If not included in the RFP process, reliability requirements will be the subject of a connection agreement regardless.

The AEMC, the AER and the dispute resolution body must be fully cognisant of the reliability of different non-network alternatives. This will enable them to make meaningful judgements on the relative merits of network and non-network alternatives.

- *Other factors*

It is important that if a non-network alternative is progressed for implementation, the cost of connection is not subsequently altered in a significant way. Depending on the non-network alternative, connection costs can be significant. If changed, connection costs could undermine a project. It is important dispute resolution procedures can address this potential issue.

16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?

We welcome the approach of the AEMC to ensure a wide range of costs and benefits are factored into network expansion decisions. However, it is notoriously difficult to properly reflect the full cost/benefit of any investment decisions. Assumptions about: load growth; future fuel costs; future emission costs; future network infrastructure costs; discount rates; future policies that may affect the energy supply chain; and energy demand characteristics, will all impact to varying degrees on the legitimacy of cost benefit analysis.

Any inconsistency in how these assumptions are applied will provide mixed or confused signals to the market about the value of non-network alternatives. To develop with confidence, markets need a degree of certainty or at least predictability about prices.

Although there may be concerns about the impact, a full cost/benefit analysis could have expansion timescales. We believe the concern that the network be expanded efficiently should be prioritised. There is limited value in rushing network expansion at the expense of efficiency. Planning frameworks must be designed to allow full cost/benefit analysis to occur.

To overcome timing and certainty issues, different non-network alternatives could be independently assessed, and be prescribed with a proxy value of 'market benefits'. This proxy may need a degree of flexibility depending on where the technology is implemented. The proxy could be applied universally to those technologies, streamlining the assessment process and providing clarity to market participants.

By way of example, an independent assessment of natural gas fired cogeneration may find it has network reliability value of $X/kW, emission benefits of $Y/kW, and miscellaneous benefits such as improved fuel use efficiency, energy security etc, that has a value of $Z/kW. Depending on the value of reliability (which would depend on the location cogeneration is implemented), it could be prescribed a value of $(X+Y+Z)kW.

When designing proxies, it would be necessary to factor in the longevity of the non-network alternatives, and how technology performance may de-rate over time. For instance, some solar panel technologies are stable for up to, or more than 30 years, while others are only guaranteed for 10 years and de-rate more significantly. Furthermore, inverters typically need replacing over 10 year cycles. So when comparing to a network build option, the net present value (NPV) calculation must factor in all costs associated with the asset over the lifetime of the asset.

Proxies could be delivered through market rules, AER guidelines or alternative policy instruments.

We believe the following should be included for consideration in cost/benefit analyses:

- the social cost of greenhouse gas emissions, as opposed to the cost of emission abatement;
- other emissions that impact on health (e.g. nitrous oxides, sulphur oxides);
- the value of energy reliability, energy security and fuel use efficiency;
- the cost of technology lock in
- sensitivity analysis which incorporates future uncertainty of fuel costs; and
- the part to whom cost and benefits accrue – specifically, investment should be undertaken that minimises costs and maximises benefits to customers, and that costs be borne by customers in proportion to how it benefits them. (This is important because benefits may not always accrue to the party undertaking the investment or to customers in an equitable way, e.g. the benefit of upgrades to CBD energy security may primarily accrue to CBD business customers, and less so to suburban households.

It would be appropriate for the list of factors to be considered in costs/benefit analyses to be prescribed in the NER, but the proxy values may need to be subject to regular review and revision and so best kept outside the rules.

17. How should the range of benefits to be quantified under the project assessment process be determined?

We believe this is the subject of the Review, as per *Question 16*.

18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?

This appears to be a circular question. Environmental benefits need to be quantified, assigned a financial value and treated accordingly. We believe this could be most efficiently done through establishing proxy values for different technologies as described in response to *Question 16*.

19. How should a net benefit test be designed for distribution investments assessments? What are appropriate circumstances where a least cost assessment should be applied, and if so, should the two limbs of the regulatory test be maintained?

Any assessment of network investment needs to factor in costs and benefits and should seek to maximise the effective utilisation of capital over time, considering the NEO and broader policy objectives. An approach based purely on cost minimisation or maximising net benefits is unlikely to deliver the NEL objective. The net benefit test needs to maximise the benefit to cost ratio at any given time. However, by taking this approach, it is important that cost benefit analyses also considers the impact an investment makes today on future investments. For instance, if an investment today is relatively costly, but opens up significant potential for future investment that has great benefit, and this needs to be considered.

20. Is there a need for a more specific decision making criterion compared to the existing regulatory test?

Perhaps more important than the decision making criteria is the structure of the costs/benefit analysis. If the analysis is too limited, any decision made will also be limited. The decision making criteria should maximize the effective utilization of capital over time, considering the NEO and broader policy objectives.

Dispute Resolution Process

21. Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSPs' annual planning processes?

The dispute resolution process should apply to assessments, but alternative measures, perhaps not best characterised as dispute resolution, may be needed to provide discipline to the planning process. For instance, interested parties may be able to challenge the legitimacy of information provided, and if successful, DB's could be penalised for providing incorrect information.

22. What is the appropriate scale of distribution projects that should be subject to the dispute resolution process? Should the threshold for the dispute resolution process be aligned with the threshold for the project assessment process?

Yes, access to dispute resolution should be available for any project assessment. Although there may be concerns over the cost of this, we believe that precedents could quickly be established that streamline future dispute resolution.

23. Who should be able to initiate the dispute resolution process?

Only parties to the project assessment should be able to dispute a project assessment. Any interested party should be able to bring a challenge to information provided by a DB in a planning report.

24. What process should be followed to resolve disputes and what should be the timing for this process? Should parties be required to undertake formal mediation process before the dispute is referred for a binding determination? What aspects of the proposed process for transmission should apply to distribution?

Disputes need to be resolved in a timely way so that any delay to network or non-network alternative investment does not compromise network reliability requirements.

One benefit from assigning proxy values to non-network alternatives could be that disputes over cost benefit assessments would be much less likely to occur. Proxy values could be established through consultation and any disputes regarding their value could be dealt with on timeframes independently of specific project assessments.

Disputes may be subject to an initial mediation process, but many disputes are technical in nature and need specialist understanding to assist resolution. The dispute process should allow for the engagement of technical experts who can advise on matters of an engineering and/or economic nature.

The arrangements for access to dispute resolution for transmission should be applied to distribution.

25. Who should make binding determinations to resolve disputes? Is the AER the most appropriate body? If a mediation process is used, who should be the mediator for disputes?

Whichever body makes binding determinations, they must be appropriately resourced to do so. This includes having access to engineering, economic and legal skills. If the AER is to make binding decisions, it is likely they would need greater capacity to deal with engineering related disputes.

26. Should the appointed arbiter have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance?

No. The arbiter should be required to inform parties to the dispute if there are grounds for immediate rejection so that the parties can amend their application for dispute resolution where possible.

27. Should the dispute resolution process be restricted to reviewing the DNSP's compliance with the NER and requiring the DNSP to amend its analysis in its project assessments or annual planning report if it is found that it has not fully complied (i.e. compliance review)? Or, should the dispute resolution process provide for a review of the outcomes of the DNSP's project assessments or annual planning report and if it is found that the DNSP has not reached the best outcomes, direct the DNSP to implement the most suitable outcomes (i.e. merits review)?

Both processes should apply.

Common Issues

28. The appropriate balance of specification on the national framework between the NER and supporting guidelines.

Where timing flexibility is required the AEMC should use supporting guidelines to guide the AER. On matters of fundamental principle, the AEMC should use the NER.

29. Should "urgent" investments be exempt from aspects of the national framework? If so, how should "urgent" be defined?

We believe that defining “urgent” is problematic and exempting certain investments from the national framework based on urgency is likely to exacerbate any conflict of interest DB’s may already have in assessing and implementing non-network alternatives.

30. What consequential amendments should be made to other arrangements to reflect the implementation of the national framework?

At this stage, we are not aware of any.

If you have any further queries regarding the details of this submission please contact Tosh Szatow, CUAC Policy Officer on (03) 9639 7600.

Yours sincerely

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