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17th May 2010

Our Reference: UE-SU-01

Dr John Tamblyn
Chairman
Australian Energy Market Commission
P.O. Box A2449
Sydney South NSW 1235

BY EMAIL TO: aemc@aemc.gov.au

(And through the electronic lodgement facility)

Dear John,

Re: Consultation Paper. National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010

Please find enclosed a submission prepared by United Energy Distribution in response to a proposed amendment to the National Electricity Rules which has been put forward by the Ministerial Council on Energy.

Should you or your staff have any queries in relation to this submission, please do not hesitate to contact Jeremy Rothfield, Regulatory Economist, on (03) 8540 7808.

Yours sincerely

Andrew Schille
Regulatory Manager

National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010. Submission to the rule change consultation by United Energy Distribution.

United Energy Distribution
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Revision Log

Rev	Revision Status	Date	Prepared by:	Checked	Authorised
A	Preliminary	11 May 2010	Dr Jeremy Rothfield		
B	Final	17 May 2010	Dr Jeremy Rothfield		

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1. Efficient investment in electricity services

1.1 Efficiency in the construction of connection assets

In Victoria, a key feature of the distribution planning cycle is the release, by distributors, of forward planning documents, including the Distribution System Planning Report (DSPR) and the Transmission Connection Planning Report (TCPR). In circumstances where a major augmentation or enhancement to the network is planned, a regulatory test must be undertaken, and AEMO plays a monitoring or oversight role in this regard. The AEMC Review of Distribution Network Planning and Expansion recommended the introduction of two new tests, the RIT-D and the RIT-T, with AEMO expected to take the lead when presiding over the latter.

The arrangements generally work satisfactorily when comparatively modest changes, or incremental expansions to the network are required. In most circumstances, the augmentations and extensions to the distribution system are underpinned by growth in electricity demand, which is typically seasonal, or, alternatively, by location-specific increases in electricity consumption. Capital expenditure is low when outlays are measured as a proportion of the regulatory asset base. The distribution planning arrangements haven't been comprehensively tested in situations where major new infrastructure is needed to connect to remote and renewable generation. The issue at stake is not that inefficiencies may arise, but rather that the incentives offered by existing arrangements may be insufficient to support and to give rise to major new infrastructure.

As a distribution business, UED is not in a position to comment directly on the efficacy and effectiveness of the existing national regime for transmission planning. However, reference should be made to a report by the Allen Consulting Group (ACG) on the implications of climate change policies for the application of the regulatory investment test for transmission (RIT-T)[1]. The ACG noted that investments in transmission networks were often made to uphold a deterministic standard, which was essentially concerned with the resilience of the network in the face of contingencies. The report also pointed to a wider range of economic benefits which would be delivered by additional transmission transfer capability. The benefits were comprised of:

- **Reduced generation operating costs**. A transmission upgrade would permit the despatch of lower cost generation which might, conceivably, be precluded from operating at present by the transmission line constraint. The economic benefit would be the difference in the average generator operating cost both before and after the transmission line upgrade.

- **Reduced generation capital costs**. If the capacity of the transmission network to receive energy from a particular location were enhanced via an

[1] Review of energy market frameworks in light of climate change policies. Climate change policies and the application of the regulatory investment test for transmission (RIT-T). A Note to the Australian Energy Market Commission, December 2008.

upgrade, then there would be greater potential to construct generation plant with lower up-front capital costs.

- **System reliability.** Investment in transmission would permit a reduction in expected, unserved energy because additional sources of supply would be connected, providing greater redundancy in the event of generation or network outages. A formal estimate of the benefits to system reliability could be obtained by conducting a Monte Carlo simulation of the predicted, unserved energy both before and after the transmission upgrade. For each of the two scenarios, known failure rates would be used for the different generation and transmission equipment. A value would then need to be assigned to the change in unserved energy.

- **Avoided transmission costs in other parts of the grid.** Building a transmission link would enable the deferral of alternative transmission projects that might otherwise have been necessary.

- **Reduced transmission losses.** Constructing further transmission plant would reduce the amount of energy that is ordinarily lost during transportation to the customer.

The ACG analysis appears to have been framed around improvements to existing transmission networks, when the emphasis should more appropriately have been on the measurement of economic benefits when a brand new transmission line has been built to link into sites of remote generation. When considering the establishment of scale efficient network extensions (SENE), benefits such as system reliability may be diffuse, because the SENE is likely to be joined to the shared network through a single connection point. The gains to reliability from a radial line may be uncertain and difficult to quantify. Furthermore, transmission line losses are likely to be significant along a SENE, precisely because long line lengths are needed to reach remote areas.

In practice, a principal source of economic benefit from a SENE is likely to be the potential to connect to low carbon intensity generation. A transmission project that permitted additional low carbon generation would reduce the cost to the industry of purchasing carbon permits, which is a valid economic benefit to attribute to the transmission upgrade.

In general, the research by the ACG cannot be used to justify the adequacy of existing arrangements for transmission planning. The ACG report only considers a particular aspect of current arrangements, notably the application of the RIT-T, and does not examine broader issues surrounding the framework for bilateral negotiations between generators and transmission network service providers (TNSPs). It is possible that the existing provisions in the National Electricity Rules (NER) provide insufficient incentives for TNSPs to build scale efficient network extensions for connections.

UED believes that the AEMC should provide specific examples of the failure of the planning and regulatory arrangements currently in place for transmission entities. Evidence of possible policy failures would provide a firmer basis for decision-making than mere presumptions about deficiencies of coverage and scope in the Rules.

Discussion points

1.1. Under the existing Rules, are inefficiencies likely to arise as a result of the significant new investment in renewable generation?

1.2. If so, do the costs associated with these inefficiencies justify amendments to the Rules?

1.3. Do you agree that the proposed Rule change will lessen the risk of the inefficient duplication of assets?

There is a potential for inefficiencies to arise under the existing Rules because network service providers are not given sufficient latitude to make plans for connecting multiple generators over a period of time. In Victoria, existing regulatory practices are influenced not only by the Rules, but also by the provisions set out in electricity distribution licences, codes and guidelines. The existing regulatory practice is geared towards providing additional network capacity in a timely fashion so as to improve reliability for customers and to meet the projected demand for electricity. The codes, guidelines and other instruments are not framed around an objective of building major new distribution links in a staged and modular fashion.

The current regulatory arrangements are unlikely to provide sufficient support for the development of scale efficient network extensions. There are aspects of the codes and guidelines which could potentially impede new developments, although the AEMC has yet to identify more precisely what these specific provisions might be. Nonetheless, there does appear to be a reasonable *prima facie* case for amendments to the Rules.

A risk associated with the new Rules is that assets built and installed under the new framework could become redundant in a time frame which is shorter than the relevant economic and engineering lives would suggest. However, UED also believes that there are adequate safeguards in the proposed Rules to mitigate against the risk of asset stranding. The consultative procedures, and the requirement to produce forecasts which are then vetted by AEMO, will lessen the risk of the inefficient duplication of assets. However, it will be incumbent upon network service providers to prepare a comprehensive range of scenarios for the forecast generation profile.

On balance, UED believes that the greater opportunities for new development afforded by the proposed Rules will offset the potential downside caused by a slightly elevated risk of asset stranding. However, there remains a significant shortcoming in the proposed Rules, and this is to do with the process of selecting an NSP to carry out the works associated with a SENE.

UED supports the notion that the process of nominating an NSP, with responsibility for putting forward options for the development of a SENE, should be presided over by AEMO, and should be undertaken in conjunction with preparations for the National Transmission Network Development Plan (NTNDP). In accordance with the proposed Rule 5.5A.2(a), AEMO should be obliged, as part of the NTNDP, to identify scale efficient generation zones and to issue instructions to the NSP or NSPs with jurisdiction to operate in the same or nearby geographic areas. The instructions should be about the preparation of a scope of work for the development of potential SENEs. Network Service Providers which are either adjacent to, or co-located with the proposed scale efficient generation zone will generally have the best information about potential connection points, and about the characteristics of the network which they themselves operate. The affected NSPs should consider all reasonable variants of the possible project and publish a preliminary scope of work. The supporting data should be published and the likely constraints should also be described. UED contends that the evaluation of the various options should not, however, be undertaken at this preliminary stage.

Applications for connection, connection enquiries, and the responses to connection enquiries, should, arguably, also be handled by the incumbent NSP. However, in the interests of transparency, and to enable contestability to be introduced to other parts of the process, the handling of connection enquiries should be opened up to scrutiny.

UED contends that contestability should be brought into the SENE planning process at a reasonably early stage. The precise phase in which contestability can be introduced is likely to depend upon administrative feasibility, the ease with which processes can be re-arranged, and the complexity of the planning and/or development tasks to be undertaken. Based on the sequence of events that is currently envisaged in the draft rule change, there would be scope to allow contestability at the 'preparation of offer to connect' stage, or when preparation of the SENE planning report has commenced. There might be some merit in allowing other participants or businesses to produce an alternative SENE planning report, however these entities are likely to be disadvantaged, relative to the incumbent, by a lack of detailed knowledge about the existing, shared network to which the SENE would be joined. Confidentiality considerations would come into play, implying that the release of the alternative SENE planning documents would need to be delayed. The incumbent would potentially benefit from asymmetric information.

A variation on the aforementioned approach would involve the introduction of competitive bidding following the release of the SENE planning report, and once a SENE connection offer had already been made. However, the incumbent would be greatly disadvantaged in these circumstances, because the terms of its offer to a generator would be revealed to other participants. The range of planning options and line configurations which the incumbent had evaluated would also be made available to other NSPs. The incumbent would be aware from the outset that its information would be liable to be disclosed to other participants, and this knowledge would dampen its incentives to participate fully and transparently in the SENE planning process.

The optimal method would be to allow bilateral negotiations to take place between generators and competing NSPs, each of which would be vying for the right to establish a regulated SENE. If the policy objective was to implement a fully competitive process, then various aspects of the proposed Rule change would need to be modified.

1.2 The sizing and location of SENEs

Discussion points: Will SENEs be efficiently sized and located so as to minimise risk to consumers? 2.1. Are NSPs likely to construct SENEs that are efficiently sized and located? Is there a significant risk of over-investment?

2.2. Are the risks associated with asset stranding outweighed by the potential efficiency gains from efficiently sized network extensions?

2.3. Does the Rule change, as proposed, provide sufficient checks and balances to minimise the risks to consumers?

There is every likelihood that NSPs will construct optimally sized and located SENEs because the process leading up to the development of the SENE will be comprehensively documented and subject to rigorous review. In particular, the Rules stipulate a wide range of information that must be incorporated in the SENE planning report. The information will be available for both formal and informal review. The data could also be used to conduct a regulatory test, even through, under the provisions of draft clause 5.5A.1(d)(3), scale efficient network extensions will be officially exempt from the requirements of the RIT-T or other applicable regulatory test. NSPs will be aware that the information will be used in a regulatory assessment process, which bears some resemblance to a *de facto* regulatory test. NSPs will therefore be disciplined in choosing carefully from amongst a range of possible development options, and will be diligent in avoiding over-investment.

The SENE planning report will be compiled and structured according to guidelines prepared by the AER. Under the proposed clause 5.5A.7, the forecast generation profile will also be subject to an assessment by AEMO. In addition, the AER will be empowered to make a determination in respect of the SENE connection offer, and may require the NSP to submit a revised SENE planning report and/or amended SENE connection offer.

UED believes that there are ample checks and balances in place because AEMO will be able to oversee part of the process, while the AER will play a monitoring role, and will also have the capacity to intervene. The risks to consumers will therefore be minimised, and will certainly be no greater than the risks which consumers currently bear through the planning processes already in place for DNSPs and TNSPs.

There is a genuine possibility of asset stranding because generators may renege on commitments to build a facility and then connect to the SENE. Clause 5.5A.11, as currently drafted, states explicitly that generators may withdraw a connection enquiry or an application to connect at any time. The implication is that generators may back away from any agreements or undertakings without sanction. The Clause appears to be designed to offer re-assurance to generators, and there is a suggestion that other generators may come along and make revised offers.

The risks of asset stranding, which result from the ease of entry and exit by generators, are mitigated in part by a provision in clause 5.5.A.5(f)(6) which appears to authorise an NSP to seek prudential support from a generator. The risks appear, on balance, to be outweighed by the potential efficiency gains that would result from the establishment of appropriately sized network extensions. Moreover, the proposed Rule change may facilitate transmission or distribution projects for which there is support by generators, but in respect of which standard regulatory tests would not yield a favourable result. Standard regulatory tests would fail to show a positive NPV, in some cases, because the market benefits are measured simply in terms of the NPV of unserved energy, with little, if any, actual value assigned to the connection of new, committed generation.

The proposed Rule change will make it more likely that new distribution and/or transmission links to remote areas are suitably sized with potential built-in for future augmentations.

If, as UED has suggested, NSPs were permitted to bid or tender for the right to build SENEs, then the potential gains for consumers would be enhanced. Consumers would benefit from being able to access the least cost or best designed option.

An important caveat on these findings is that NSPs should either have access to, or else should be able to produce, planning information that is well researched and of high quality. NSPs generally have strong capabilities in network planning because the addition of new links and segments is a core business function. For major projects, external assistance is often sought to supplement internal expertise.

At present, NSPs possess only limited experience in the task of forecasting generation output, although TNSPs probably have a larger number of employees with the requisite skills than DNSPs. Distributors are better equipped to formulate projections of electricity load and consumption. A requirement of clause 5.5A.5(c)(1) is that both transmission businesses and distributors would be required to present a best estimate of the forecast generation profile in the SENE planning report. Hence, the two types of business would need to assemble in-house teams with suitably skilled personnel.

In preparing forecasts of generator output, NSPs would remain heavily reliant on the information provided by the proponents of generation projects. In particular, generators would have the best information about the precise location and capacity of generating plant, and would also be better placed to give an indication as to the likely dates of installation and commissioning. NSPs would develop the forecast generation profile by aggregating the data from individual generating units. NSPs would be unable to verify business specific cost information, and would instead have to resort to industry benchmarks. However, generic market information covering pool prices and the prices of renewable energy certificates (RECs) would be readily available. NSPs would also have access to data on the marginal cost of generation from particular fuel sources using specific technologies.

The consultation paper has noted that accurate forecasts of the entry of future generation are a pre-requisite to ensuring that the potentially large costs associated with under-utilised assets are attenuated. NSPs will use their best endeavours to formulate projections of generation output but will still have to make educated guesses about the timing and viability of the more marginal generation projects. Accordingly, the mandatory review by AEMO of the forecast generation profile will provide an important safeguard for consumers. Under the proposed clause 5.5A.7, AEMO will be obliged to assess whether an NSP has employed reasonable methods and assumptions in deriving conclusions about the magnitude and profile of the anticipated generation output.

UED believes that the clause should be strengthened so that AEMO is required to provide explicit endorsement of the forecasts if it is satisfied that the methodology, assumptions and conclusions are reasonable. There should also be obligations placed on AEMO to ensure that it remains accountable and does not simply use the review process as an opportunity to reject the SENE planning report put forward by an NSP. If AEMO is not satisfied with the forecasts submitted by an NSP, then, as the market operator, it should be required to either:

- Suggest improvements to the methodology, assumptions and techniques employed; or

- Compile and document an alternative set of projections, using external assistance where necessary and applicable. The forecasts should be developed transparently.

1.3 Are alternative risk mitigation measures more appropriate?

Discussion points 3.1. Who benefits from SENEs and who is best placed to manage the risk of asset stranding? 3.2. Should the framework include a more explicit economic efficiency test? If so, what form might it take? 3.3. Would a market-based approach to the sizing and location of SENEs be more appropriate? If so, what form might this approach take?

At the outset, the beneficiaries from a SENE project can be expected to be the parties which gave rise to it. Generators to whom a connection offer was made will benefit because they will have access to the SENE at regulated charges. The Rules as currently proposed will require generators to pay a fixed annual SENE charge which is expressed in terms of dollars per megawatt (MW) of connected generation capacity. In effect, generators will only have to pay for their reserved capacity. The operators of generation facilities will not have to pay for unused capacity on the network which has been built to accommodate future increases in generation output. In addition, generators will not be obliged to bear the risk of asset stranding, even though they are, arguably, the parties in the strongest position to manage the risk. If the proposed Rules take effect, then the proponents of generation projects may well find that schemes in remote areas which were previously unviable, owing to a lack of distribution or transmission network capacity, are suddenly more feasible.

The developers and operators of a SENE will benefit by earning a regulated return on the network assets which they have constructed. Prices and charges will be determined in a similar manner to the prices and charges determined for the principal regulatory asset base owned and operated by the relevant NSP. For TNSPs, the form of regulation applied to the SENE will be a revenue cap, whilst for DNSPs, the form of regulation will be a price cap.

In the short term, consumers will be required to fund any shortfall amount in the relevant network service provider’s annual SENE revenue requirement. However, consumers will still benefit in totality because the SENE is likely to be motivated by a desire to gain access to low marginal cost forms of renewable generation. Consumers will therefore gain by being able to tap into electricity generated from distant renewable sources. The benefits to consumers will be more pronounced in the event that a carbon pollution reduction scheme is implemented. This is because the marginal cost differential between low and high carbon intensity sources of generation will either be maintained or else will increase, depending upon the interactions observed between the market for RECs and the market for carbon abatement.

Consumers will gain further advantages if, as UED has argued, competitive bidding is brought into the process for allocating rights to build a SENE. UED believes that the choice of NSP to develop a SENE should not simply be determined through bureaucratic means.

1.3.1 Economic cost-benefit appraisal

An additional test for economic efficiency is not required and may be unhelpful because there are generally comparatively few options available when the development of infrastructure links to remote areas is being contemplated. However, there is certainly a strong case for examining the merits of any proposal for a SENE via a broadly based economic impact assessment, or economic cost-benefit analysis. The evaluation should be divided into two categories: The costs and benefits of the SENE proposal to the electricity market, and the broader societal costs and benefits. The conduct of a regulatory test is generally circumscribed by the narrower considerations of the electricity market, with costs and benefits evaluated from the perspective of agents which consume, produce or transport electricity. In contrast, a more general economic assessment would take into consideration all of the effects on social and economic welfare.

The rationale for a wider economic cost-benefit analysis is that significant green field projects such as new transmission or distribution links may not be justifiable when only the narrow financial costs and electricity market benefits are considered. A more extensive economic analysis would consider the effects on agents other than the parties immediately involved in the transaction. Importantly, government policy on renewable energy hasn't simply been motivated by a desire to satisfy energy needs at lowest financial cost. Government policy on renewable energy has been underpinned by objectives including the development of new technologies, a reduction in fossil fuel dependence, and a decrease in the carbon intensity of electricity generation.

Regulatory tests such as the RIT-T specifically preclude the measurement of externalities, with the latter defined as spill-over effects that accrue to parties other than those which produce, consume or convey electricity. The AER guidelines on the RIT-T state that the classes of costs and benefits to be considered are those which are incurred or obtained, respectively, by parties in their capacity as consumers of electricity[2]. Thus, the costs or benefits which arise but are incidental to parties' electricity consumption should be exempted from an analysis under the RIT-T.

An economy-wide cost-benefit analysis would incorporate some of the costs and benefits measured in a RIT-T assessment, but would also consider the more general ramifications for a regional or State economy, or the nation as a whole. Externalities would typically be valued or estimated, and then included as a line item. When undertaking an evaluation of a distribution or transmission link to a remote area with

[2] Regulatory investment test for transmission application guidelines (draft). Australian Energy Regulator, March 2010.

strong potential for renewable energy, the types of effect that might be measured are summarised below:

- Greater competition amongst generators in the electricity market.
- The prolongation of fossil fuel reserves.
- The benefits from carbon dioxide abatement, measured using the marginal social costs of carbon emissions. Note that these social costs differ from the marginal traded cost of permits for carbon dioxide.
- The impact of fewer disruptions to electricity supply.
- The encouragement given to the exploration and development of renewable resources.
- The stimulus to new industries, and to the harnessing of new technologies.
- The promotion of regional economic development, taking into account displacement effects and resource constraints.
- Other effects on the natural or built environment.

The forecast financial costs to be incurred in building and operating a SENE would also be appropriately included in an economic cost-benefit appraisal. Since the SENE is connected to a shared distribution or transmission network, then the costs of deeper augmentations to the existing network should also be taken into account. A deeper augmentation would, in this context, mean an expansion to the shared network, occasioned by the linkage to the SENE, which went beyond the installation of connection assets, and extended further into the distribution or transmission system than the first point of transformation. Importantly, the costs of deeper augmentation should only be added to the project costs of SENE development, to the extent that recovery through the normal tariff mechanisms is not feasible.

Suitable guidelines for cost-benefit analysis include those prepared by the Commonwealth Department of Finance[3].

The option to undertake an economic cost-benefit analysis should be made available to NSPs under the proposed Rule change. NSPs would engage suitably qualified practitioners to conduct the work, and would then, at their discretion, submit the results of the analysis with the SENE planning report. NSPs would have the option to include categories of cost and benefit that are plausible, realistic and amenable to measurement or valuation.

The Rule change proposal should also contain provisions which would require the AER to make use of the results from the economic cost-benefit analysis. The AER would take the costs and benefits into account when making a determination about

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3 Handbook of Cost-Benefit Analysis, January 2006. Commonwealth of Australia. Financial Management Reference Material, No. 6.

the SENE connection offer and the SENE planning report. However, the Rules should also express clearly that NSPs would not be compelled to submit cost-benefit analyses in circumstances where the NSP deemed that there would be little merit in so doing. An NSP may validly decide that a full cost-benefit analysis is unnecessary.

1.3.2 Market-based options

The AEMC should explore more fully the range of market-based options that might be available for the development of SENEs. In particular, incentives may need to be provided to promote the establishment of privately-owned distribution and transmission network links. Investors in these networks would need assurance that their assets would remain undeclared and unregulated, and that they would not be forced to provide third party access. The owners of the networks would also need to be able to earn above average rates of return. In these circumstances, generators might be more prepared to underwrite the costs of a network extension. However, they would still require customers who would be prepared to pay higher than normal rates for transmission and/or distribution tariffs.

Market-based options would present a greater likelihood of the inefficient duplication of assets over time.

1.4 Configuration of connections to the SENE

Discussion points: Will generators be able to connect to the SENEs in the most efficient configuration?

4.1. Should the draft Rule allow for configurations other than a “hub and spoke”?

4.2. If so, how could the charging arrangements best promote efficient locational decisions by generators and by NSPs in locating SENEs?

4.3. Should the costs of the SENE be spread across all generators irrespective of where they locate?

The draft Rule change should be flexible enough to permit the emergence of alternative design configurations for the SENE. There is absolutely no requirement for the Rules to be prescriptive on design features, even if, on the available evidence, the hub and spoke seems to represent the preferred form of spatial arrangement. If guidelines on appropriate design features are needed, then these should be prepared by the AER, with expert input from electrical engineers. In general, however, neither the Rules nor the guidelines should seek to restrict configurations for the SENE because to do so would potentially result in less efficient network designs being chosen.

When the SENE is first built, charges for connecting to it should be based on the reserved generation capacity, and not on the physical location of generators. The geographic position of the hub will have been chosen so that it is convenient for the majority of generators, and the AER will have reviewed the process leading up to site selection. The SENE will have been developed in such a way as to minimise the net present value of the aggregate costs of connecting a series of generators over a period of time.

A reasonable interpretation of the proposed Rule change is that the location of the SENE will not be overly influenced by the position of the first connecting generator. The two infrastructure installations may be co-located, but this will not automatically be the case. An alternative position may be chosen for the SENE if there is evidence that the majority of the generators which are expected to connect at a future date will be situated elsewhere.

The disregard of generator location, when apportioning the capital and operating costs of the SENE to generators, should not continue on an indefinite basis. A case can be made that location-based charging should take effect after a certain, pre-determined period of time, although location specific charges should not be applied retrospectively to pre-existing generators.

A new charging regime could take effect after a pre-determined period, though it would not be applicable to foundation generators. Under this system, newly-connecting generators would be 'rewarded' for locating close to the hub of the SENE by being subject to discounted charges. In contrast, generators which set up operations at a distance from the SENE would pay a higher unit rate for the capacity charge. Importantly, however, the 'penalty' for being further away should not be excessive because the guiding philosophy behind the SENE (and the underlying purpose of the infrastructure) was to expedite and facilitate connections to remote generation.

UED believes that the AEMC should explore further the notion of differential charging regimes for generators spread across different locations.

1.5 Classification of services

The mechanisms that are invoked to charge for the use of the SENE will depend, in part, on the manner in which the service is classified. Clause 5.5A.1(d)(1) of the proposed Rule change states that scale efficient network extensions will be:

> Negotiated transmission services or negotiated distribution services comprising Generator transmission use of system services and Generator distribution use of system services (as relevant).

UED believes that the classification of the SENE as a negotiated service would be appropriate if the Rules were modified to allow competitive bidding amongst NSPs for the rights to build, own and operate a SENE. However, the current expectation, based on the proposed Rule change, is that the requirement to construct a SENE would depend upon the geographical location of an incumbent NSP, and would be determined by AEMO through a bureaucratic process. In these circumstances, UED has cause to question the merits of the classification of the network extension as a negotiated service.

The AEMC consultation paper on the SENE has not presented the arguments leading up to the classification of the service, but UED considers that reference should be made to the Transmission Revenue Rule which was discussed in an AEMC Rule Determination dated November 2006[4].

[4] Rule Determination. National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18. Australian Energy Market Commission, 16th November 2006.

The Revenue Rule defined Prescribed Transmission Services as those services provided by shared network infrastructure, where there were strong economies of scale and where network externality benefits existed, such that competition for these services would not be economically feasible. Prescribed Transmission Services were also said to be limited to services that have relatively uniform performance characteristics across the network.

In contrast, Negotiated Transmission Services were defined in the Revenue Rule as services dedicated to or requested by specific parties which are characterised by either a lack of homogeneity, limited market power, or material countervailing buyer power.

The categorisation of the services provided by the SENE needs to be reviewed in light of these definitions, and in the context of the additional discussion presented in the Transmission Revenue Rule decision paper.

For Negotiated Transmission Services, in relation to which there are fewer market failure concerns, the Revenue Rule specifies the less intrusive and less administratively costly commercial negotiation form of regulation. The end-users for these services are likely to be larger and better resourced, providing a counterweight to the market power possessed by the TNSP and making commercial negotiation a feasible proposition. Moreover, requiring generators and large end-users to negotiate with TNSPs about the recovery of costs directly incurred by the TNSP as a consequence of their connection will ensure that the efficiency of those costs is subject to scrutiny by a well informed and commercially interested counter-party.

There are a number of considerations which suggest that if the SENE is a transmission network, then the services which it provides should be more appropriately classified as prescribed. Firstly, there are scale economies in the construction of transmission lines, meaning that, for a given line length, the incremental costs of building a higher capacity network are less than the average costs per megawatt of building a network with an ‘average’ level of capacity. Economies of scale are a distinguishing feature of prescribed services.

Secondly, there are significant network externalities associated with the SENE, and chief among these is the benefit made available to consumers by being able to consume electricity generated from low carbon intensity sources. The marginal social cost of the avoided carbon dioxide emissions is a positive externality. Another externality is provided by the shared nature of the network. Competition for the services that it provides would not be feasible because the network cannot be supplied to consumers in a piecemeal fashion. In addition, duplication of the infrastructure would be both costly and inefficient.

Thirdly, transmission services should really only be classed as negotiated if there are few or no market failures apparent, and if the end-users of the service are well-resourced, and capable of acting as a bulwark against the market power possessed by the TNSP. In the context of the SENE, neither of these conditions would appear to be satisfied. The market’s apparent inability to deliver distribution or transmission line linkages to remote areas has prompted the Rule change proposal that is currently under review. As discussed previously, the AEMC has not adduced direct evidence of the failure of the market, however there appears to be a lack of confidence in the willingness and resolve of market participants to deliver major new network extensions in a timely fashion. Furthermore, electricity from renewable generation will be used by all types of electricity consumer, and not simply the large customers that are capable of exercising influence over the electricity market. The ultimate end-users of the services provided by a SENE will, potentially, be millions of residential electricity customers.

UED therefore concludes that in transmission networks, the services provided by a SENE should be prescribed transmission services.

If the SENE is a distribution network, then negotiated distribution services would be a similarly inappropriate classification. In Victoria, the AER has limited the coverage of negotiated services to the following types of activity and service:

- Connection and augmentation works for new customer connections.
- New public lighting assets; and
- The alteration and re-location of existing public lighting assets.

The categorisation provided above is current as at the date of the AER Framework and Approach paper for Victoria[5]. In their regulatory proposals, the Victorian distributors have questioned the appropriateness of categorising new customer connection and augmentation works as negotiated distribution services on the grounds that such an approach would be inconsistent with current Victorian regulatory arrangements. The AER has recognised that the existing Victorian guideline[6] concerning the partial recovery from customers of the capital cost of new works and augmentation should be maintained in some form.

The upshot is that the grouping of the SENE as a negotiated distribution service category would be inconsistent with service classification arrangements in Victoria.

2. Efficient use of electricity services

2.1 Will capacity be efficiently allocated to connecting generators?

Discussion points:
5.1. Will the framework promote the efficient allocation of capacity on the SENE?
5.2. More generally, will the SENEs framework result in efficient outcomes in the wholesale market?
5.3. Could an interruptible generator connect to the SENE? If so, what arrangements would need to be in place to ensure that the full cost of the SENE can be recovered?

5 Framework and approach paper for Victorian electricity distribution regulation. Citipower, Powercor, Jemena, SP AusNet, and United Energy. Regulatory control period commencing 1st January 2011. Final version prepared in May 2009.

6 Electricity Industry Guideline No. 14. Provision of Services by Electricity Distributors, Issue 1. Essential Services Commission, Victoria, April 2004.

The allotment of capacity on the SENE will take place through negotiations between the NSP and groups of generators, and the outcomes achieved should reflect the wishes of all participants. Negotiation is a reasonably efficient method of determining the initial capacity, and then divvying it up between generators. There is a risk, however, of strategic behaviour by individual generators. A generator may choose to adopt a wait-and-see approach rather than engage in discussions. The particular generator would only apply to connect once the SENE had already been built. If capacity on the network had been fully allocated by that stage, then the in-coming generator would have the option of funding an augmentation to the SENE. Strategic behaviour would be more likely to occur if the incremental cost of network augmentation were less than the initial contribution that the generator would have to make to develop a full scale network, which offered the same share of overall capacity, from the outset.

There is a reasonable expectation that the SENE framework would result in efficient outcomes in the wholesale market. However, the AER would have to consider a range of possible approaches to calculating an administrative marginal cost that would be applied to determine the compensation due to constrained generators.

Interruptible generation should only be permitted once a group of incumbent generators has subscribed fully to the available capacity on the SENE. To sanction interruptible generation when there is unallocated power transfer capability on the SENE would potentially encourage “free-riding”. This is because the interruptible, self-despatching generators would not have a contract for capacity on the SENE, and would seek to avoid paying amounts which take proper account of the network’s capital and operating costs.

2.2 How could loops to the shared network and load connections to SENEs best be accommodated?

Discussion points:

6.1. Should SENEs be “ring-fenced” from the shared network to enable the framework to operate? If so, should a time limit apply to such ring-fencing arrangements?

6.2. Alternatively, how could SENEs best be incorporated into the shared network? In particular, how could the challenges arising from capacity rights to the former SENE best be addressed?

The SENE should be ring-fenced for the entire duration of its economic life. Alternatively, if the SENE were incorporated into the shared network at some stage, then compensation payments would be due to the holders of capacity rights on the formerly separated part of the network.

3. Concluding remarks

The pricing arrangements under the proposed Rule change would result in the coverage of economic regulation issues under chapter 5, as well as under chapter 6 of the Rules. A separate determination would be required once every five years for each SENE, and there could, potentially, be several SENEs in a distribution network.

If the SENE were a distribution network, and the services which it provided were classified as standard control, then the pricing arrangements under chapter 6 would require only limited adjustment to become applicable under chapter 5.

Finally, UED believes that AEMO should consider whether thresholds ought to apply before particular zones are identified and declared as being fit for the development of SENEs. The types of threshold which might be examined would include a minimum size limit on generators, either individually or in aggregate, and a specific criterion for geographical remoteness.