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EnergyAustralia®

12 June 2009

Dr John Tamblyn
Chairman
Australia Energy Market Commission
Level 5
201 Elizabeth Street
SYDNEY NSW 2000

By email to submissions@aemc.gov.au

Dear Dr Tamblyn

**AEMC Review of Demand Side Participation in the National Electricity Market**

EnergyAustralia welcomes the opportunity to respond to the AEMC's Draft Report of 29 April 2009 into Demand Side Participation in the National Electricity Market. EnergyAustralia operates Australia's largest distribution business and has developed significant expertise in demand side participation (DSP). During the last five years, EnergyAustralia has carried out many effective DSP projects including:

- Active take-up of a range of projects approved under the IPART D-factor regime. Twenty two demand management projects have been implemented within EnergyAustralia's network since 2004 to 2008 costing a total of $5.6million. These projects have affected $135 million worth of capital investment;
- The roll out of approximately 400,000 smart meters and over 227,000 customers with Time of Use (ToU) prices – ToU is the standard offering for new and upgraded sites;
- Australia's largest pilot program of dynamic (critical) peak pricing, involving over 1,000 customers; and
- Trial of 1700 AMI meters with a view to test ability of AMI to facilitate customer response.

Historically, regulators and policy makers have attempted to increase the use of DSP to defer or substitute network investment. Regulatory arrangements have experienced varying degrees of success in delivering significant levels of DSP and have either focussed on modest (but positive) incentives for network deferral or information disclosure requirements which have evoked little, if any, proponent response.

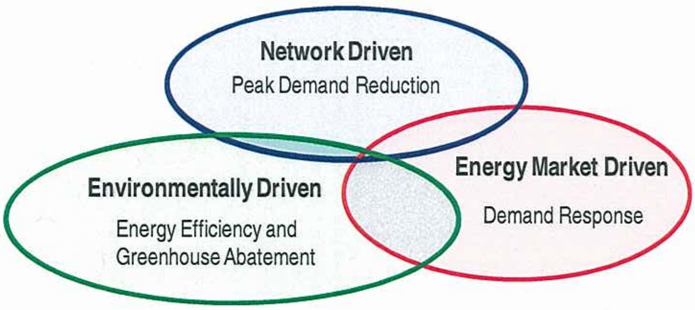
EnergyAustralia agrees with many of the findings of the AEMC in relation to the barriers inherent in the Rules to the development of efficient DSP and will support appropriate Rule changes. We are confident that DSP will develop further in the short term if the right signals and incentives are developed. However, current arrangements may not sufficiently provide the necessary signals.

It is also worth noting that there are a range of investments undertaken by DNSPs for which DSP is not typically appropriate, and it is important that regulators understand this inherent limitation.

A particular matter which EnergyAustralia believes has not been given sufficient weight in the AEMC's review is the interplay between differing forms of DSP. This needs to be recognised as a major determinant of the level of incentive which will be necessary to enable a DNSP to deliver economically efficient DSP, where this also provides benefits to other sectors of the industry and to consumers.

In considering the effect of the substantial array of greenhouse and energy efficiency policy initiatives on a DNSP, it is necessary to distinguish between DSP initiatives which are implemented in the electricity market for quite different purposes. Three distinct drivers of DSP must be considered:

- ***Environmentally driven.*** These include all Government sponsored greenhouse gas abatement and energy efficiency policy measures, which are mainly aimed at encouraging reduced overall energy consumption or fuel substitution.
- ***Energy Market driven.*** Primarily aimed at reducing bulk energy purchase costs by reducing energy consumption in high pool price periods, possibly by transferring consumption to lower price periods.
- ***Network driven*** (traditional demand management)***.*** Targets reducing the capital expenditure on the network by reducing demand during periods of network congestion, possibly by transferring consumption to periods of lower network loading.




These forms of demand management and their interrelationship are depicted below.

The essential points to be made concerning this diagram are as follows:

- Environmental and energy efficiency options, which encourage an overall reduction in consumption, are unlikely to have a great effect either on high energy market prices or network congestion, both of which have durations of a small number of hours per annum. However, for DNSPs subject to a price cap, these measures can have a marked effect on revenue where such impacts have not been included in forecasts. For example, the federal Minimum Energy Performance Efficiency standard which was initially applied to set top boxes and external power supplies from 1 December 2008 will have the effect of reducing the energy consumption of appliances which are typically permanently connected to the supply. However a reduction of 1 MWh in the annual consumption will have an effect on the maximum demand of only about 0.1 kW.
- The converse also applies, in that measures targetted to reduce consumption during network and market peak periods do not necessarily have much effect on overall consumption.[1]

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1 EnergyAustralia has seen some reduction in usage during peak times that does decrease overall usage. For example, a decision to turn off an air-conditioner during peak network times, typically does not defer the usage, but results in a real reduction of energy

- Finally, there is a very poor degree of correlation in the NEM between network congestion periods, which are related to periods of high demand, and periods of high energy market price. In 2007-08, the correlation or $R^2$ between the half hourly NSW demand and pool price was 0.07. This is illustrated below (the trend line is curved because of the logarithmic scale of the Regional Reference Price).
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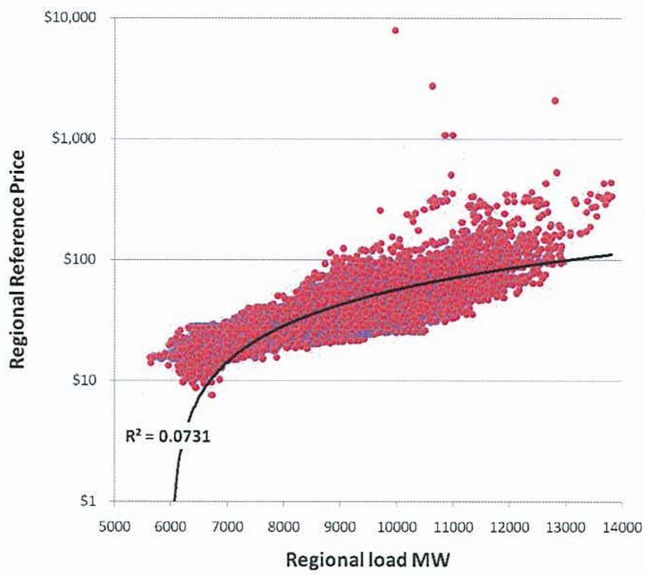


A second high level issue which EnergyAustralia wishes to draw to the attention of the AEMC is that of consistency of approach between its concurrent reviews of DSP and the Framework for Distribution Planning and Expansion.

In this review of DSP, the AEMC has effectively proposed that sufficient incentives to elicit efficient DSP are created through the economic regulatory framework and the form of price control. Additional support or incentives to promote the deployment of operational-level DSP are not considered necessary.

On the other hand, the principal focus in the AEMC's review of the Framework for Distribution Planning and Expansion appears to be the imposition of an excessively broad and onerous range of reporting and information requirements for DNSPs, aimed at rectifying some perceived disadvantage by DSP proponents.

These two propositions - that DSP faces a comparative disadvantage, and that economic signals within current frameworks are sufficient to allow implementation of DSP – cannot both be true and highlight a potential inconsistency in the treatment of DSP in the current reviews being undertaken by the AEMC.

We include specific comments on the AEMC's draft report on DSP in the attachment and discuss the proposition of whether incentives are in fact sufficient to implement DSP. The section headings of the report have been retained in the attachment in order to facilitate reference to the source.

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consumed. However, a decision to defer using a pool pump or a dishwasher to non-peak times merely defers the energy being consumed and therefore does not reduce overall consumption.

EnergyAustralia will separately respond to the AEMC in relation to Distribution Planning and Expansion.

Should you have any questions in relation to this submission please contact Ms Catherine O'Neill on 9269 4171.

Yours sincerely

**TREVOR ARMSTRONG**
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# Attachment - Comment on draft AEMC Report of 29 April 2009 into Demand Side Participation in the National Electricity Market

(Note that headings below are from the AEMC's draft Report.)

## 2 Economic regulation of networks

### *Network prices and the ability of consumers to respond*

There are two aspects with very different timeframes involved in setting efficient prices for customers.

***Long term considerations***

Standard distribution prices are of necessity averaged across customers. It is important that the long run costs of network augmentation are built into prices and that economic cross subsidies between customer classes are removed through cost reflective pricing.

Tariff design and prices are dependent upon the type of metering installed and the frequency with which it is read and billed. For small customers with Type 6 meters (accumulation meters), which comprises the majority of the demand imposed on the network, a form of inclining block tariff is the most cost reflective variant available. An inclining block tariff applies a lower price to consumption below an amount and a higher price for consumption above that amount. For customers with Type 5 meters (interval meter), a ToU price with differential energy rates can reflect the cost of network expansion during peak load periods.

***Short term considerations***

Averaged distribution prices are unable to convey the costs associated with supply to specific geographic areas and supply situations Where augmentation of the network is required due to capacity constraints, it may be efficient for higher short-term price signals to be employed, to elicit a greater customer response to reduce consumption at times of peak local demand. Prices like dynamic or critical peak pricing[2] and baseline load pricing[3] have been demonstrated to elicit significant response. Further, direct load control (such as that trialled in South Australia) may be used in agreement with customers in concert with a range of tariff structures.

As the AEMC has recognised, these short term pricing signals and controls require bilateral communications and contracting with the customer to be effectively implemented. It is also worth noting the importance of the framework that allows the network to have a relationship with the customer. If this relationship does not exist, there is potential for network pricing signals to be swamped by retail pricing initiatives that may not be aligned with those of the network business.

Pricing in the conventional sense is not the only means of conveying a short term economic signal for change in demand. Many successful demand management programs have involved working directly with customers to identify, facilitate and sometimes fund changes to equipment or practices that lead to lower peak demand. These actions provide a benefit to those customers who participate, rather than a cost to those who do not. Such demand management programs can be considered as part of the overall 'pricing' package the customer sees and reacts to, and can be much more flexible, in both geographic and temporal terms, than tariff based approaches.

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2 Critical peak pricing is when high prices are set for critical peak times which are typically of short duration as an incentive to customers to avoid paying higher prices and lower their overall bill.

3 Baseline load pricing is similar to critical peak pricing, but instead of a "stick" mechanism of higher prices, customers are incentivised to reduce load during critical peak times through a rebate – a "carrot" for reducing consumption.

***Framework for regulation of prices***

The AEMC has found that the WAPC form of price control provides the appropriate incentives for DNSPs to deliver peak-use prices that reflect marginal cost. EnergyAustralia agrees with this proposition. However, limitations in network price structures, primarily due to metering, preclude fully cost reflective pricing.

Another aspect of the WAPC form of price control which must be considered is the volume risk that is associated with targetted, cost reflective price signals. This can act to limit the extent to which a DNSP will pursue DSP through tariffs, particularly as the reduction in capital expenditure which is being targetted may not materialise during the current regulatory period.

Examples of cost reflective tariffs that create an increased volume risk for the DNSP are as follows:

- ***Inclining block tariffs*** - where there is a significantly higher price in the upper consumption block, the DNSP becomes more vulnerable to the loss of revenue due to initiatives like the CPRS and energy efficiency;
- ***Time of Use*** – peak period network prices are generally significantly higher than the average network price and off peak prices significantly lower. In the case of EnergyAustralia's 2009-10 prices, this differential between the ToU peak and off-peak price components is 240% of the average energy rate. As a consequence, a customer that responds to the peak price signal by shifting a kWh of energy consumption (which is what the tariff is designed to achieve) would reduce revenue by far more than a customer on a standard tariff that saved a kWh of consumption.
- ***Dynamic (critical) peak prices*** – this approach involves very high prices, imposed for specific, relatively short periods (say 2 hours) on a number of occasion during the year (say 12 events in total). Extensive trials have demonstrated the effectiveness of these signals, but EnergyAustralia has decided not to proceed to further trial or implement this form of pricing. A major reason for this decision is that under the WAPC there would be a very significant proportion of revenue that is typically earned at peak times being placed at risk of not being recovered. There is also a very strong incentive to impose peak period prices up to the agreed maximum frequency, even if there was no reason to manage demand at the time in order to recover as much revenue as possible in order to cover allowed costs.

EnergyAustralia therefore believes there is a continued need for the regulatory support of targetted, cost reflective pricing initiatives directed at evoking DSP. This would best be achieved through incentives to mitigate tariff revenue loss in the current period in an extension of the AER's DMIA regime to tariff based demand management initiatives.

***Economic regulation and the profitability of DSP for networks***

The AEMC has found that a profit maximising price-capped network business has commercial incentives to offer DSP inducement payments up to the difference between the network charge and the peak demand capacity costs avoided by DSP and that this equates to the payment required to achieve a socially efficient level of DSP.

EnergyAustralia accepts that, in a theoretical economic sense, the AEMC's finding may be valid. This approach aligns with the AER's stance in its recent Framework and Approach papers for several jurisdictions, where tariff related losses are restricted to the (very constrained) innovative demand management projects undertaken under Part A of the DMIS.

Whilst this approach may be theoretically correct, it fails to recognise the many issues associated with the practical development of DSP, including:

- The additional transaction and procurement costs associated with establishing DSP, as against a network augmentation which is well understood and has a guaranteed outcome that will meet the constraint;
- The fact that not all demand management alternatives will address a network constraint – the solution must match the time of day and duration of the constraint, must be geographically located to be able to address the constraint, and must be of sufficient size to meet the constraint.
- A lack of equivalent DNSP experience and familiarity with demand management alternatives;The variability of demand management measures in their relative tariff impact, which for small customers is generally driven by energy consumption; and
- The risk that the DSP solution may not deliver, or not deliver a sufficient demand reduction to avoid overloading of system assets or shedding load.

Some positive form of incentive is necessary to overcome the barriers which discourage a rational DNSP from carrying out DSP. It should be noted that IPART's D factor, established during the 2004-09 determination, included provision for an incentive payment to offset risks related to the use of non-tariff demand management as well as the revenue impacts associated with demand management projects such as power factor correction that result in lower volumes. This scheme has been reasonably successful in providing an incentive for NSW DNSPs to invest in DSP. The scheme did not result in an overinvestment in demand management during the course of the 2004-09 determination, but did deliver DSP that had an impact on capital deferral.

***Economic regulation and financial risk for networks using DSP***

The AEMC has correctly identified that there are different incentives under the regulatory regime applying to capital and operating expenditure. EnergyAustralia agrees that there are inherent structural aspects of the regime that may potentially disadvantage DSP relative to supply side solutions.

DSP generally involves additional operating expenditure (payments for demand reduction) in order to defer or reduce capital works. An unintended bias against the adoption of DSP in created by the fact that over-expenditure on operating expenditure hits DNSP's bottom line where DM payments have not been included in operating forecasts. This is particularly the case where such payments are ongoing. As the AEMC notes, the DNSP must justify operating costs to the regulator at the time of the reset and faces risk that its forecast costs will not be allowed.

In the 2009 regulatory proposal, EnergyAustralia calculated the expected cost of implementing an amount of demand management that was estimated to be achievable as part of its capital program for the 2009-14 period. The AER rejected the operating costs associated with these projects, but accepted the capital deferral that was used to smooth the program. As a result of the AER's decision, EnergyAustralia will now need to achieve its demand management program without funding to cover the expenditure of implementing these programs. There is no deferral of capital that will be achieved relative to the forecast within the period, as the forecast agreed to by the AER has already extracted this benefit. This is unreasonable and EnergyAustralia has argued will impact our ability to recover the efficient costs associated with meeting the capital expenditure objectives in the 2009-14 period. The AER's failure to accept the costs associated with demand management whilst accepting the forecast benefits sends a clear signal to DNSPs that Regulators will more readily approve costs associated with supply side solutions than those associated with demand side solutions.

The AEMC is incorrect in its statement on p25 that "the residual (i.e. undepreciated) value of capital expenditure incurred during the five-year period just ended is 'rolled in' to the Regulatory Asset Base".

The AER has decided to use actual depreciation to establish the regulatory asset base for the NSW DNSPs at the commencement of the 2014–19 regulatory control period.[4]

Under the current regulatory regime, the financial incentives are as follows:

- The incentive to avoid capital expenditure comes from the return on, and return of, capital components which may be incurred or avoided until the end of the determination. This incentive varies with the timing relative to the next review and is in the range of 20-45% of the capital value.
- Operating expenditure is subject to the AER's EBSS, in which a carryover mechanism is designed to ensure the incentive to reduce opex is the same regardless of the timing of the expenditure. A sustained change in operating expenditure compared with the regulatory allowance attracts a fixed bonus (or penalty) of approximately 25%.
  Because operating expenditure is subject to review by the AER at the next determination, there is an additional risk that that expenditure under a DSP agreement which spans the reset may not be approved by the AER.

Some partial solutions to these issues discussed in the draft AEMC report include:

- The removal of operating expenditure on DSP from the EBSS;
- The introduction of an equivalent efficiency carryover mechanism (ECM) for capital expenditure; and
- Not subjecting ongoing DSP payments to regulatory approval at the reset.

Comments on the above alternatives are as follows:

- Removing operating expenditure on DSP from the EBSS would be a worthwhile step in providing a level playing field for demand management.
- The introduction of an efficiency carryover mechanism for capital expenditure would not be favoured, since the existing incentive already has the potential to be "high powered".[5] EnergyAustralia argued against the adoption of this high powered incentive in its 2009 regulatory submissions. The further modification of this regime to deliver a constant five-year loss of return on and return of capital would deliver an excessive incentive structure.
  Whilst the AEMC has not detailed whether the capital expenditure ECM would apply to all capital expenditure or only to that affected by DSP, its partial application would be asymmetric, by only carrying over the benefit of deferred expenditure.
- An arrangement whereby ongoing contracted DSP payments were not subject to regulatory scrutiny would remove uncertainty as to their funding.

EnergyAustralia has pointed out above that there remains a need for some form of positive incentive payment to DNSPs to offset the risks to long term and short term revenues associated with an efficient level of DSP. EnergyAustralia has found that IPART's D-factor was sufficient to facilitate an effective level of DSP, although other mechanisms could be used.

IPART's D-factor regime allowed DNSPs the benefits of capital deferral to be absorbed, but also provided a positive incentive payment (that was set at an amount equivalent to the cost of the project) to overcome the inherent disadvantages and risks in choosing DSP options.

EnergyAustralia has consistently maintained that the only effective means of ensuring an efficient level of DSP is utilised by DNSPs is to ensure that the private interests of the DNSP are aligned with the

4 Final decision - New South Wales distribution determination 2009–10 to 2013–14, Australian Energy Regulator, 28 April 2009, p81.
5 A high powered incentive is an incentive that incorporates the loss/gain of both depreciation and the return on capital for any over - / under-expenditure on capital.

broader public interest. Because the practice and markets for DSP are in their infancy there are significant skill, information and experience barriers to be overcome before it can compete on an equal footing. Without positive incentives and neutralisation of disincentives, DNSPs commercially prudent decisions will remain conservative and weighted toward well understood and well rewarded conventional network options.

By providing DNSPs with a refund of the whole of DSP costs for the deferral of works already included in the capital expenditure allowance, it may appear that IPART allowed the duplication of funding to meet or manage demand. However, IPART recognised that some form of positive incentive was necessary to overcome the range or risks and disincentives associated with the use of DSP. It found that this was a simple, reasonable and proportional basis to set the value of the positive incentive and encouraged DNSPs to undertaken DSP that was inherently more risky than traditional network investment.

***Incentives for innovation***

EnergyAustralia believes its current IPART regulatory regime, including the D-factor, provides a moderately effective incentive for DSP using proven technologies. In the last 5 years, EnergyAustralia has invested in the order of $2 billion of growth-related capital expenditure and has undertaken a demand management investigation process for each augmentation projects with an estimated cost greater than $1 million. Approximately $135 million of this growth-related capex has been impacted by non-network alternatives. Some $12 million of benefit has been achieved through deferred capital investment and $5.6 million spent to date in direct costs to achieve these savings.

On the other hand, the D factor arrangements are inflexible in that they only apply where some deferral of investment can be demonstrated. There is therefore a bias against funding development of innovative or unproven DSP, even though it may deliver future benefits. Despite this lack of flexibility, EnergyAustralia has felt obliged to undertake some limited research during the current regulatory period, in order to explore more effective and innovative ways to facilitate and achieve demand management outcomes.

In its regulatory submissions during the 2009 determination, EnergyAustralia consistently supported the introduction of an innovation allowance (or I-factor), modelled on the scheme which was so successfully introduced in the United Kingdom. An innovation allowance in the vicinity of 0.5% of annual revenue was envisaged, as is the case in the UK. OFGEM's I-factor arrangements have been used to overcome a barrier in existing regulatory regimes (such as ours) with regard to innovation. The I-factor has supported a wide range of innovation activities that extends beyond DSP related innovation, although the majority of funding has been directed to demand management and energy efficiency development.

In ESCoSA's 2005 determination, ETSA Utilities was provided with an allowance of approximately $20 million to develop demand management, representing around 0.8% of revenues over the period. The scheme is subject to firm regulatory oversight and has been used by ETSA Utilities to develop a broad range of demand management options, including their Peakbreaker+ approach to the direct control of air conditioning and other appliances currently being trialled.

The AER, however, continues to set very low limits for its equivalent Demand Management Innovation Allowance (DMIA). In its 2009 determination, the AER permitted EnergyAustralia funding of $5 million over five years[6]. This represents only 0.06% of the allowable revenue. The AER has continued to set

6 Final decision - New South Wales distribution determination 2009–10 to 2013–14, AER, 28 April 2009, pp203, 265.

very small proportionate limits for DNSPs and most recently indicated its likely approach will provide an aggregate of $20 million to the five Victorian DNSPs during their 2011-15 regulatory period.[7]

EnergyAustralia strongly supports the AEMC's finding that ESCoSA's framework is appropriate for implementation in the NEM. However it is apparent that clear guidelines to the national regulator will be necessary to ensure that the funding to be applied to innovation is sufficient to achieve any worthwhile outcome.

It should be noted that IPART's D factor scheme was never intended to fund innovation. In fact, the requirements for high levels of confidence in achieving specific, identifiable deferrals mean just the opposite. EnergyAustralia argued at the time that a form of innovation funding was necessary in addition to the D-factor to enable less well understood demand management options to be explored and developed to the point where they might be able to be considered for implementation under the D-factor approach. The DMIA is a step in this direction, but remains too low.

## 3 Service Incentives and Reliability Standards

***Mandatory service standards – planning and reliability standards***

EnergyAustralia agrees with the AEMC that network options and DSP options are not perfect substitutes as they generally offer different probabilities of meeting and managing network demand. This mismatch may be exacerbated by design planning conditions which impose a strictly deterministic (n-1) level of system security.

It is acknowledged that an economic approach to the analysis of planning options which extends to the probability and expected value of meeting demand is a theoretical ideal. This would accommodate DSP options and network planning options on an equivalent basis within a uniform planning framework. However, it is not practicable to apply such a framework to the myriad of augmentation projects that are associated with distribution networks. The extent of analysis applied to a large number of projects needs to be proportional to the estimated value and type of investment.

A more appropriate solution for the higher voltage levels of distribution networks is the development of design planning conditions which are in effect a hybrid of the deterministic and probabilistic approaches. Such a standard is in the form of a deterministic (n-1) rule, but supplemented by a maximum permissible number of hours at risk above that level. This approach imputes a value on customer reliability. It permits a guided level of judgement to be exercised by the DNSP concerning the type of load and its duration near the peak, offset by the expected effect of any DSP.

We note that in NSW, load at risk is allowed within the licence conditions for major urban and non-urban substations. However, the licence conditions explicitly exclude load at risk for the CBD and for large substations. This reflects the NSW Government's view that the associated benefit of reliability in these circumstances outweighs the costs of providing that level of reliability.[8]

***Discretionary service standards – service incentive schemes***

The AEMC has found that service incentive schemes do not provide a barrier to DSP as they allow DNSPs to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits.

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7 Final Framework and approach paper for Victorian electricity distribution regulation - Citipower, Powercor, Jemena, SP AusNet and United Energy - Regulatory control period commencing 1 January 2011, AER, May 2009.

8 Design, Reliability & Performance Licence Conditions for Distribution Network Providers, Dec 2007.

This finding is believed to be theoretically correct. However, such incentive schemes will inevitably lead to a greater focus on the expected relative performance of network augmentations with DSP alternatives. The increased risks (or perceived risks) associated with DSP alternatives will be imputed an expected economic value by the service incentive schemes.

One option would be to modify service incentive schemes to at least partially exclude poor performance arising from the non-performance of DSP. As a preferred arrangement, explicit subsidies to ensure the development of economic DSP would include the reimbursement of any expected service incentive effects.

## 4 Distribution Network Planning

***Distribution network planning***

Distribution network planning requirements are only broadly covered in the Rules and the AEMC's current review of the national framework for electricity distribution network planning and expansion is designed to address this.

The jurisdictional planning requirements for DNSPs are in most cases detailed and specific. Most involve the publication of a detailed system development report, which is intended to identify through preliminary screening tests any opportunities for DSP and elicit a response from potential DSP proponents.

With regard to the suggestion on p39 that the current five-year planning horizon for distribution networks did not permit sufficient time for DSP proponents, EnergyAustralia would point out that it is in the interest of DSP proponents that a firm commitment to rectify a specific capacity shortfall is made before expressions of interest in such solutions are sought. Within distribution networks, a limited number of major projects such as those addressing zone substation and subtransmission system capacity issues would be sufficiently well defined more than five years in advance.

EnergyAustralia supports the national adoption of a five year planning and reporting horizon for sub-transmission assets for the purpose of informing DSP of forecast constraints. It should however be noted that at a distribution level constraints often arise from the actions of individual customers and may only be known 1-2 years in advance.

EnergyAustralia accepts that there is sufficient diversity in the jurisdictional arrangements to present an issue for some DSP proponents. EnergyAustralia agrees it is appropriate that the proposed National Framework for Planning and Expansion require a thorough and transparent consideration of DSP and other non-network options and the harmonisation of the current jurisdictional reporting arrangements is supported as a positive step. However it is worth noting that EnergyAustralia's experience[9] indicates it is a misconception that publishing large amounts of information in distributors' annual planning reports will, at least at this point in time, provide the information necessary to facilitate development of, and opportunities for, the market to provide efficient demand management options.

Other approaches are likely to be much more effective in promoting the development of non-network solutions. These might include, for example, establishing a Demand Management Register of Interested Parties, information exchange with Interested Parties regarding; potential demand management opportunities, current demand management policies, and updates on the progress of demand management initiatives; provision of incentives to assist in the development of the market for

9 EnergyAustralia has undertaken approximately 170 Demand Management investigations in the last 5 years.

non-network options; and special purpose public consultations related to specific opportunities. EnergyAustralia has found such communication channels to be an effective and efficient mechanism to distribute information to DSP proponents without imposing significant additional cost of the DNSP, and has developed these approaches in response to the desire to achieve more cost effective and widespread use of DSP, not as a result of regulatory requirements.

EnergyAustralia looks forward to participating in the development of the national arrangements during the AEMC's distribution planning review.

***Consultation and case-by-case assessments***

The AEMC has raised the possibility that since the threshold value for application of the Regulatory Test relates to the value of the network augmentation, this may bias consultation in favour of network options. EnergyAustralia does not believe the current arrangements result in biased outcomes, as all economically feasible alternatives are accorded equal treatment.

The Transmission Regulatory Investment Test which is the subject of a draft Rule determination by the AEMC now requires that the test be undertaken when a transmission planning issue exists and the most expensive economically credible option is estimated to cost more than a threshold dollar amount. The AEMC considers it may be appropriate for a similar change to be made for distribution network planning and will consider the matter further as part of the distribution planning review.

If the Regulatory Test threshold were to be based on the most expensive economically credible option, this option could not be the most cost effective and therefore would not be selected. Moreover, the DNSP would not be sufficiently aware of all non-network options to reasonably determine the cost of DSP options in specific installations and customers' circumstances.

The application of the Regulatory Test for distribution already imposes a significant administrative burden and any lowering of the threshold or change to the threshold which causes an increase in the number of instances for which it would be required, would be inappropriate. Indeed, EnergyAustralia believes that raising the threshold of the Test for distribution augmentations would be appropriate, in order to relieve its significant administrative burden, and would not have a negative impact on the level of demand management implemented across our network.

In addition to the current requirements for new investment in the Rules, EnergyAustralia is also subject to longstanding jurisdictional requirements, in the form of DNSP Licence conditions imposed under the Electricity Supply Act 1995 (NSW). EnergyAustralia would in principle support the development of similar national provisions for inclusion in the Rules and looks forward to achieving this through participation in the AEMC's distribution planning review.

## 5 Network Access and Connection Arrangements

***Connection arrangements and minimum technical standards***

***The process for connection***

The AEMC has found that for the connection of small generators, the detailed connection process in the Rules which is available to all connecting parties irrespective of their size reduces any barrier to connection applicants which may be imposed by jurisdictional arrangements. EnergyAustralia supports this conclusion.

***Minimum Technical Standards***

The AEMC considers that the arrangements covering the minimum technical standards create a barrier to embedded generators below 5 MW connecting, since the minimum technical arrangements of the Rules do not apply and the various jurisdictional arrangements apply in their place.

In principle, EnergyAustralia would support the inclusion of a greater level of guidance in the Rules on the technical requirements for smaller generators and looks forward to contributing to their development. However, in establishing threshold levels to which the guidelines and standards apply it is important to ensure that the limitations of the network at the proposed point of connection are factored in. That is, it is not necessarily the size of an embedded generator which determines the technical requirements which apply to ensure the ongoing safety, reliability and quality of supply to customers, but the capacity of the generator compared with that of the network at the point of connection. Very small generators can present technical issues on remote rural distribution networks.

***Connection charges***

The connection and pricing framework under the Rules is the same for transmission and distribution connected generators. The only difference which applies to embedded generators is their eligibility for the reimbursement of "avoided" TUoS charges.

The AEMC's statement on p51 "Generators that are connected to the transmission network only pay the costs directly attributable to their connection (i.e. shallow connection costs)" is only correct for those transmission connected generators that were in place at the commencement of the NEM. The generator connection arrangements embodied in the Rules would require a new generator to negotiate a connection arrangement which could well include deep connection costs, if that were required for that generator to adequately access the market. This is the same as for distribution connected generators.

***Benefits of embedded generation***

The AEMC finds that the existing avoided TUoS arrangements provide appropriate price signals and should be retained.

EnergyAustralia does not agree with this position and has consistently maintained that the current avoided TUoS regime simply constitutes a subsidy paid by customers to embedded generators, rather than being justifiable on economic grounds. Quite apart from being founded on an assumption that the variable TUoS charge and its structure represent the long run avoided costs of the transmission network, in EnergyAustralia's experience this arrangement has presented two very significant disadvantages:

- It is unstable, in that at a transmission connection point where the load and generation are closely matched, the variable TUoS rate will increase asymptotically[10], dramatically overstating the avoided TUoS payments to any embedded generator in that portion of the distribution network.
- It can significantly distort the generator's preference of connection voltage and location, in networks configured like EnergyAustralia's. EnergyAustralia has had first-hand experience of this aspect with negotiation of the connection of a large generator (which did not in the end proceed) in the inner Sydney suburbs. The generator preference was for connection at 33 KV, which would have embedded it within the distribution network and entitled it to a substantial avoided TUoS rebate, rather than to the nearby 132 KV transmission network.

EnergyAustralia therefore favours a more transparent approach whereby any avoided augmentation costs are directly assessed by the TNSP (on an averaged regional or connection point basis for smaller generators) and applied directly, rather than the current distortionary avoided TUoS regime.

[10] The variable TUoS rate is the allocated variable cost divided by the net volume at the connection point. The allocated variable cost relates to the maximum utilisation by loads of adjacent transmission network elements at the particular point of connection and will thus reflect a period when the generator is out of service and the full load connected to the transmission network.