Submission to the Australian Energy Market Commission

Review of Demand Side Participation in the National Electricity Market

Stage 2: Issues Paper

UNITED ENERGY Distribution

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UED KEY MESSAGES

- United Energy Distribution (UED) recognises that Demand Side Participation (DSP) has potential to deliver significant benefits through better utilisation of assets, lower network investment costs and market benefits through lower peak demand and more efficient prices. It is recognised that there may be unnecessary impediments to non-network solutions in the current framework.
- However, UED observes that the removal of presumed impediments to DSP requires a focus on three key matters for an effective regulatory framework:
  - The regulatory framework should foster a culture of innovation within the businesses to uncover DSP solutions by giving distributors maximum opportunity to discover business solutions to solve potential network constraint problems;
  - DSP will not be maximised through central design from regulators, using regulation and control. Rather, effective DSP solutions require the experts within the businesses themselves to be engaged in developing the necessary solutions together, with network customers and demand side experts generally;
  - The removal of impediments should be efficient and avoid creating a new set of distortions, so that businesses are not required to systematically favour either network or non-network options.
- UED submits that the most timely process for articulating both network and non-network solutions is at the stage of submitting a regulatory proposal for approval by a regulator. At this stage, the distributor is able to put forward a complete package of policies and processes network and non-network solutions and initiatives, quantify the benefits and costs, and seek appropriate funding.
- This is measurably superior to a piecemeal approach of relying on specific regulatory approval for expenditure on demand-side solutions under Rules, guidelines or formulas. These alternatives are uncertain in their application, and diminish incentives for businesses to respond in the most effective manner to DSP opportunities.
- A key task is to establish a regulatory design which encourages businesses to be innovative and not unduly risk-averse in seeking demand-side solutions. UED submits that this will only occur when there is a minimum of detailed regulatory control, and when businesses are able to retain realistic rewards for their successes in applying these solutions.

INTRODUCTION

Background to UED

United Energy Distribution (UED) is one of the largest Victorian electricity distributors and provides services to some 600,000 end-users in Melbourne's southern and eastern suburbs.

UED is responding to the Australian Energy Markets Commission (AEMC) issues paper solely from the viewpoint of a distributor.

Structure of submission

The issues paper has identified potential barriers to DSP in:

- economic regulation of networks
- network planning
- network access and connection arrangements
- wholesale markets and financial contracting
- reliability

The submission responds to the majority of the 16 sub-issues raised in the AEMC's paper under the above headings. We have offered no comments at this time on wholesale markets and financial contracting, and make only brief comment on reliability.

1 Objective of the review

The terms of reference of the review state that the aim of the current review is to examine the Rules more broadly to identify barriers to efficient DSP, and to develop proposals for Rule changes to reduce or remove them when efficiency would be improved.

UED welcomes the comment in the introduction to the issues paper that obligations on participants in the electricity market related to *reliability, security and quality of supply* cannot be considered as impediments to DSP. UED agrees with the view in the issues paper that these are legitimate requirements of the market.

UED considers that any proposals for changes to the Rules to reflect DSP must give full consideration to potential effects on *reliability, safety, security and quality of supply* as well as efficiency. Network users have high expectations of the services to be provided by distributors, and meeting these expectations must be a distributor's first priority.

2 Potential barriers in the economic regulation of networks

2.1 The balance of incentives may not encourage the efficient inclusion of demand-side options

General

UED acknowledges that the highly structured 'incentive' features of regulation (including the carryover of penalties into subsequent regulatory periods) can act as a disincentive to DSP. This adds weight to UED's view that businesses should be able to make proposals for efficient demand-side solutions early in the regulatory reset process and receive clear approval for those proposals.

Under the National Electricity Rules (NER) one objective of operating expenditure (opex) is to allow businesses to manage demand. Therefore an allowance for expenditure on specific demand management initiatives could be provided as part of a business's opex forecast at the time of presenting a regulatory proposal. For the Australian Energy Regulator (AER) to approve forecast opex for demand management, that forecast would have satisfied the opex requirements in clause 6.5.6 of the NER[1].

Once approved through a distribution determination, opex for demand management would be treated the same as any other category of opex.

Preference for capital over operating expenditure

In Victoria, the regulator has recently removed the capex component of the efficiency carryover mechanism (ECM) and we consider that incentives for businesses to seek efficient capital spending reductions, including use of DSP, may have suffered as a result.

UED would support a balanced incentive regime, which combined incentives for efficient capital expenditure and a fair sharing of efficiency benefits from avoided expenditure (including through demand-side projects). The aim would be to provide adequate incentive to pursue efficient DSP without exposing the businesses to additional risk through service standard penalties and unrealistic forecasts of expected efficiencies from DSP.

Service reliability and DSP

The issues paper correctly identifies an interrelationship between incentives for service reliability in the Rules and incentives for DSP.

DSP projects typically offer lower reliability than network options.

[1] The Rules have a similar provision for consideration of demand management in a DBs capital expenditure forecast (capex) (clause 6.5.7 of the NER).

This has practical implications for the kinds of projects that can be pursued by businesses. Where penalties of failure to meet service targets are high, the risk assessment must reflect this higher cost.

2.2 The building blocks control setting method may limit the incentives for innovation on demand-side participation

Research, development and innovation schemes

Specific funding should be provided as an incentive for businesses to undertake research, development and innovation on demand-side options.

As a small example, the ESC in Victoria has included a modest allowance in the regulatory revenue requirement for each business for negotiating and developing technical/operating standards, and legal costs associated with entering agreements with demand-side suppliers.

There are current (although limited) examples of the willingness of regulators to support 'pure' network innovation and research and development. UED observes that the AER will apply a 'demand management innovation allowance' in NSW and the ACT in the 2009 to 2014 regulatory control period (up to $1 million per annum). The AER may apply a version of this scheme to the Queensland and South Australia resets for the 2010 to 2015 regulatory control period.[2]

Need for policy direction in the Rules

Overall there is a lack of policy incentive within the National Electricity Rules (NER) for research and development on DSP. Although, as noted, the AER has recognised the value of allowing revenues for DSP research, there is no requirement for the AER to do so. UED submits that the Rules should positively encourage businesses to seek funding for DSP research, development and innovation.

As an alternative to providing stand-alone funding for research and development, the Rules should allow a business to identify in a regulatory proposal the level of funding for research and development it requires. When approved, the funding should simply be a component of the total building blocks revenue allowance.

2.3 The form of price control may not facilitate efficient demand-side participation

Form of price control

UED considers that the choice of price control (whether price, revenue or hybrid cap) should be based on the most appropriate control for a particular network, rather than its DSP

[2] AER, Issues Paper, Potential development of demand management incentive schemes for Energex, Ergon Energy and ETSA Utilities for the 2010-15 regulatory control period, April 2008 p 15.

incentive properties. UED notes that the National Electricity Rules do not favour one form of control over another, and UED strongly supports this arrangement.

When regulated under a price cap, businesses will always face a disincentive to pursue DSP projects that pose risks that the business will not recover approved revenue.

UED would support the Rules including an incentive mechanism that compensates businesses operating under the price cap form of control for the revenue lost as a consequence of undertaking efficient DSP initiatives. One way to address the issue is by adjusting the load forecast for the next regulatory period (during price resets) by the aggregate value of DSP taken up in the current period.

If this were a Rules requirement, then it would (from the business's perspective) remove any perceived distinctive for DSP. Essentially, this is a carry over mechanism akin to the opex carry over mechanism. However, it may be unduly complex to make this type of adjustment. UED therefore recommends that alternative approaches also be investigated for compensating businesses operating under price caps.

Another approach is the NSW D factor scheme

The NSW D factor scheme is a cost recovery mechanism for business spending on demand management. Its key characteristic is that it balances the risk exposure faced by businesses for demand management compared with network investment. It does this by ensuring that a prudent demand management project will recover its costs regardless of whether expected demand management efficiencies are achieved or not. While not necessarily advocating a D factor nationally, UED commends its risk-reducing properties for businesses[3]. This should be a key consideration when considering alternative ways of enhancing the uptake of DSP under a price cap regime.

UED notes that the AER has opted to retain the NSW D factor scheme for application to the ACT and NSW 2009 distribution determinations.

2.4 The structure and components of tariffs may not provide customers with efficient signals about electricity use

Pricing principles

Efficient price signals are an important aspect of an efficient market. UED supports approaches which remove distortions and barriers to efficient pricing. Such distortions may include:

- side constraints on pricing
- restrictions on tariff reassignment

[3] The scheme places a ceiling on eligible demand management projects that can be included in the D-factor, which is the expected value of avoided distribution costs. This is a very high threshold for projects to pass, which ensures that only efficient projects will proceed.

The Rules provide that side constraints need not apply to customers with remotely read interval metering (cl 6.18.6). This is obviously necessary to obtain the potential DSP benefit of time of use pricing available with advanced metering infrastructure (AMI or 'smart meters').

Benefits of AMI

Advanced metering is expected to provide scope for distribution and retail businesses to offer more efficient prices that signal the costs of energy usage and the provision of peak load capacity. In turn, this is expected to encourage customers to respond to time-of-use price signals, leading to a reduction of energy consumption at times of peak prices.

However, AMI is at an early stage in Australia, and the extent of consumer response to time of use tariffs is subject to some uncertainty. There is very limited Australian data as to how consumers would be likely to respond to fully cost reflective pricing. Some issues are:

- determining what 'costs' should be reflected in prices – ie whether fully location specific, short term marginal costs (which may be very volatile); or longer term marginal costs which may be smoother. The latter would be likely to have a lesser effect on revealing network management options;
- If network cost reflective pricing does not completely flow through to customers, the potential demand response will be muted, with reductions in the demand-side benefits. In this regard, UED considers that any regulatory barriers to retailers passing on network time of use tariffs should be removed;
- There are equity issues for vulnerable customers, who may be exempted from time of use pricing (or require compensation).

National meter trials and extensive customer research may resolve several of these uncertainties.

Capacity pricing

For managing demand through price signals, UED considers that capacity pricing structures are a more efficient form of pricing than the current arrangements where the majority of the charge to small customers is a usage (non time-related) component. This type of pricing assists customers to accept load control, load cycling and capacity limitation as various means of limiting their exposure to higher prices.

Capacity pricing should be accompanied by appropriate demand resets for end users. Any regulatory barriers to capacity pricing (both at the network and retail levels) would need to be removed.

3 Potential barriers in the network planning arrangements

3.1 The Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered

Regulatory Investment Test (RIT)

The issues paper appears to raise concerns that the current test as applied to distribution may be inhibiting demand side options. The AEMC has clarified that its current review of the Regulatory Investment Test (RIT) will only apply to transmission and not distribution.

Given that a RIT for distribution is a matter for future policy development and consultation, UED is unclear why the issues paper is addressing this matter now.

UED cautions that any proposals to apply a lower threshold test to distribution augmentations would result in an unmanageable, unnecessary and costly regulatory investment test. This is due to the fact that the bulk of distribution augmentations do not have market impacts. Further, distribution incurs a significantly greater number of small augmentations compared to transmission. Any widening of the current RIT to solely address perceived DSP issues, without consideration of equally important objectives under the Rules, would most certainly increase costs for disproportionate benefit.

3.2 The planning arrangements may not allow sufficient time for demand-side options to integrate in the planning process

Victorian planning process and DSP

UED agrees that the market would benefit from some level of information disclosure and planning requirements on network businesses regarding upcoming constraints and proposed augmentations.

In UED's view, the main contributors to effective *public* demand-side participation are transparency, lead times and information provision.

In Victoria, businesses are required to publish an annual planning report. This covers five years and includes information on load forecasts, load at risk, planning standards and a list of projects having potential for non-network options, including opportunities for demand-side solutions.

Businesses do not publish small network constraints in the five-year forecasts. Projects are generally limited to sub-transmission lines, zone substations and high voltage lines as required by the Victorian Electricity Distribution Code. Large customer initiated connection projects are excluded from the above process due to a need for timely completion.

The issues paper suggests that demand-side proponents need more time to develop potential solutions. UED considers that a five year planning horizon is more than adequate for proponents to assess what demand-side contributions they can make, and for network businesses to respond. UED observes that businesses may, at the same time as other proponents, be evaluating their own demand-side options.

UED considers that businesses should not be directed to actively seek demand-side proponents. Businesses should only be required to publish network constraints and the market should respond with demand-side options. UED has a number of proposals which it believes will assist DSP:

- businesses should develop capacity network tariffs and be adequately funded to do so;
- businesses should be compensated for ‘feed-in’ tariffs (i.e. paying customers with small roof mounted photovoltaic cells for the energy they feed into the grid). UED considers this will greatly encourage small demand-side provision in the market.

3.3 Consultation on augmentation options rather than on the needs of the network may create a bias against demand-side options

UED observes that demand and supply side options cannot be considered in isolation from each other. For efficient evaluations, they must be considered in parallel.

The scenarios put forward in the issues paper appear to assume that businesses will always have a particular network default option to counter a demand-side proposal. UED does not consider this to be the case. When network plans are published with a long time horizon, it is unlikely that the network businesses would have developed specific default options at that time. Further, both the market and network businesses will have adequate time to develop optimal demand-side proposals.

4 Potential barriers in network access and connection arrangements

4.1 Arrangements for avoided TUOS and DUOS may under / over value demand management options

Avoided TUOS payments

The issues paper correctly identifies some of the shortcomings of the current approach of payment to embedded generators for avoided TUOS and DUOS charges.

UED considers that TUOS payments should only be recovered where embedded generators contribute to the deferral of transmission network expenditure at an individual or aggregated level. Predetermined payment under the Rules causes other customers to bear greater costs for transmission services without any benefits from identified deferred expenditure, effectively leading to a double counting of benefits and additional costs to other users. Embedded generation does not require more favoured financial treatment compared with other demand-side options such as interruptible load or reduced load.

Where embedded generators can offer quantifiable network support capabilities, network businesses have an incentive to negotiate for access to those services through network support agreements. This assumes that the Rules provide appropriate incentives to pursue demand management.

UED recommends that the Rules should remove the requirement for businesses to make avoided TUOS payments to embedded generators or demand-side providers. The same would apply to avoided DUOS payments where there is no quantifiable benefit.

The Rules should continue to provide for businesses to make network support payments to embedded generators or demand-side providers, where the planning and regulatory investment tests in the Rules identify that non-network solutions represent the most efficient means of alleviating a network constraint.

Note: In Victoria, businesses are required pass through a share of any identified avoided DUOS costs to embedded generators. The amount is negotiated between the parties.

4.2 Minimum technical standards for connection to the network may provide a barrier to potential embedded generation options

UED supports the development of consistent connection arrangements for small embedded generators (assuming the generators themselves have reasonably consistent features). UED notes that the Chapter 5 technical standards of the National Electricity Rules has recently been revised to reflect minimum connection requirements, but still allow for individual connection arrangements.

Nevertheless, UED recognises that there could be greater consistency in technical connection standards across jurisdictions in order to streamline processes and reduce transaction costs.

For larger generators, some degree of streamlining of the application and connection process may be possible. Currently, the Rules provide for both automatic and negotiated connection standards.

For micro embedded generators (for example, photovoltaic cells on domestic customer premises) no connection agreements are required in Victoria, thus removing impediments and simplifying the connection processes. The concerns of both distributors and generators were addressed in amendments to the Victorian Electricity Distribution Code.

4.3 Deep connection costs to the network may be a barrier to potential embedded generation options

Shallow and deep connection costs

Economically efficient pricing would reflect the costs which both transmission and distribution connected generators impose on networks. This would require embedded generators (and load customers) to meet the costs associated with shared network usage as well as the direct costs of their dedicated (shallow) connection equipment.

Just as benefits of embedded generation should be accurately recognised and compensated, so should the costs. In this regard, embedded generators are no different to new customer loads which have a similar size and impact on the network.

The definitions of “shallow” and “deep” connection costs can vary. In Victoria, the Essential Service Commission, has defined shallow connection costs as the cost of connection and any network augmentation up to and including the first point of transformation. In UED’s view, this is an appropriate and objective definition of shallow connection costs.

In summary:

Embedded generators should pay for all connection costs, shallow & deep, required to provide them with agreed power transfer capabilities. For deep connection cost, proponents would pay for a share reflecting their usage. If the Rules require embedded generators to only pay shallow costs, then the boundary of what is considered to be shallow becomes an important point. We support the Victorian definition of “shallow”. Embedded generators should share costs associated with reducing fault levels, which are generally “deep”.

4.4 Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided

Pricing of negotiated connection charges

The current approach for connection of large embedded generators is essentially a negotiate-arbitrate regime, guided by a number of regulatory requirements and checks. This means that price and service elements are usually negotiated and resolved with a proponent as part of a single connection and use of system contract.

Connection charges for large generators are likely to remain part of a negotiate-arbitrate regulatory approach. This is because connection requirements for large generators usually must be tailored to the particular characteristics of the site and generator in question.

It is important, however, that the dispute resolution processes are proportional to the size of the connection, and exclude consideration of aspects that are appropriately subject to commercial negotiation.

Non-price issues (access standards)

UED's view is that existing technical standards in the schedules of Chapter 5 of the Rules reflect the minimum connection requirements for embedded generators (even if they appear to be excessive for the size of embedded generators that distributors generally deal with). However, there is sufficient flexibility in the Rules for businesses to negotiate acceptable access standards with proponents.

5 Potential barriers in wholesale markets and financial contracting

5.1 Wholesale market processes may exclude potential demand-side resources from efficiently participating

5.2 The costs of involvement in the wholesale market and in financial contracting may be unnecessarily high

5.3 Demand-side participants may not be adequately compensated for providing a demand-side response

While these are all important issues, UED does not wish to comment at this time.

6 Potential barriers in the reliability framework

6.1 The use of a short-term emergency reserve trader may not facilitate the development and use of efficient demand-side participation for reliability

To the extent that a reserve trader mechanism (of some kind) underpins demand-side options, then this may assist networks in planning and developing their own options at lower cost. It is possible that the existing reserve trader scheme, being only an emergency response, leaves a "gap" in the market which creates uncertainty about system reliability. Thus, it would not appear that the existing scheme is optimal in encouraging demand-side options.

6.2 The use of reserves may not allow demand-side participants to obtain a fair market value for their services

A permanent system reliability mechanism would appear to benefit all network parties, both supply and demand-side, by providing greater certainty about the kinds of investments that they need to make. The NEM places maximum emphasis on reliability, and to the extent that DSP proponents cannot formulate secure proposals because of doubts about reliability, then the "demonstration effect" of potentially useful DSP options may be weakened.