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RE Power of Choice: Giving consumers options in the way they use electricity

As a global supplier of across the energy value chain with 116 years' experience in the Australian market, General Electric (GE) welcomes the opportunity to provide its comments on the Australian Energy Market Commission's (AEMC) "Power of Choice: Giving consumers options in the way they use electricity" draft report.

GE notes and supports the objectives of the AEMC review "identifying opportunities for consumers to make informed choices about the way they use electricity.... [and] addressing the incentives needed for network operators, retailers and other parties to maximise the potential of efficient DSP and respond to the consumers' choices, in a manner that minimises the total cost of electricity services".

The draft report identifies nine areas of effort to implement the objectives of the review and the then Ministerial Council of Energy direction for the Stage 3 Demand-Side Participation (DSP) Review "should seek to identify market and regulatory arrangements that enable the participation of both supply and demand side options in achieving an economically efficient demand/supply balance in the electricity market".

These nine areas of effort, as recommended by the AEMC, are:

1. rewarding DSP in the wholesale market;
2. gradually phasing in time varying network tariffs;
3. protecting vulnerable consumers;
4. separating DSP actions from the sale and supply of electricity;
5. enhancing consumers' ability to access consumption information;
6. enabling technology (metering);

7. distribution network incentives;
8. establishing formal consultation when setting network tariffs; and
9. energy efficiency measures and policies.

GE provides smart metering and demand response software to the retail and distribution sectors (as well as selling consumer electrical appliances). In this context, we seek to contribute to the AEMC's understanding of the economics for vendors, and the costs and benefits along the energy value chain to the consumer. GE's input relates particularly to meters and adjacent technology, but also encompasses distributed generation and demand response management platforms.

GE's response and recommendations are set out as follows:

1. response to proposed meter specification;
2. indicative pricing for smart meters;
3. other issues relating to smart meters;
4. other technologies for which efficient investment incentives may need to be reviewed;
5. availability of information; and
6. impact on existing load control activity.

1) Response to proposed meter specification

GE notes the recommended minimum specification for meters is for a very low level of minimum metering functionality. Based on GE's experience, low-functionality meters are likely to be replaced earlier in their lifespan, as consumers seek to take advantage of time-varying tariffs and smart appliances that require full-function meters.

In addition, meters that are currently being produced in volume for international metering markets have far greater capability than the minimum specification metering; these meters (which can satisfy the current NSMP specification) benefit from substantial economies of scale. If AEMC's current proposed minimum specification were implemented, a lower end meter would need to be developed specifically for the Australian market, and it would not benefit from these international scale economies.

Future tariffs are important because meter assets are generally expected to last 10 or 15 years. As a result, it is important to consider all of the benefits that could be expected to accrue to a high-functioning meter which is amortised over that time frame. Of those benefits, more flexible and efficient tariffs are one of the most important. However, many of these more efficient tariffs will depend on substantial penetration of smart appliances[1], a phenomenon which is not expected to happen in the next three to four years.

Tariffs that take advantage of full-function meters could include direct load control or automated user-configurable load control. Direct load control involves the retailer, aggregator or network directly switching an appliance, such as putting an air conditioner into compressor-cycling mode.

[1] Smart appliances based on the full Smart Energy Profile specification will include sub-metering as well as the capability to communicate wirelessly with the meter, including exchanging price updates and load control signals with the individual appliance. As a result, a substantially broader set of tariff options is opened up once smart appliance penetration starts to increase.

Automated user-configurable load control involves an automated response (configured by the user) to price signals sent by a retailer or an appropriate third party. For example, the consumer might configure their energy management such that when the price reaches a certain threshold, the pool pump is to defer operation, and at a higher threshold, the air conditioner will start cycling. Such price signals could include the full range of time-varying pricing (including critical and variable peaks), and could be triggered by any participant in response to either market or network constraints. Automated, user-configurable response would substantially reduce the consumer's transaction costs (for example, the effort of getting off the couch to switch off the pool pump in exchange for a relatively small dollar sum) while triggering action that reflects the consumer's marginal utility of consumption (for example, cycling the air conditioner above a certain price point). As a result, they would allow consumers much greater flexibility to respond efficiently to the full range of issues that affect power prices, based on each consumer's personal circumstances.

The implications for low-function meters are as follows:

> ***At the time of initial installation***, it may be that retailers offer relatively few of these more-flexible tariffs, and penetration of smart appliances (which are helpful in taking advantage of the home area network functionality of full-function smart meters) is likely to be low. A rational consumer, faced with these facts and unaware of the future potential of full-function smart meters, might be inclined to choose a low-function meter, and expect to get value from that meter for ten to fifteen years.
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> ***By halfway through the meter's useful life*** (five to eight years after deployment), it is likely that penetration of smart appliances and availability of rich tariff plans will be substantially greater. Indeed, this is AEMC's express goal. This is unlikely to have been clear to many consumers at the date the choice was made on metering. Any consumer who has chosen a low-function meter would not be able to take advantage of these tariffs or smart appliance functionality without incurring substantial cost in replacing their meter. The result will either be inefficient replacement of meters, or consumers being unable to access efficient tariff options.

In addition, full-function meters benefit from substantial economies of scale in international markets. A meter produced to the existing national smart meter specification (similar to that used in the Victorian deployment) would be able to be sold in South Africa, New Zealand, Australia, Brazil and Chile – markets with an aggregate total of over 70 million meters. A minimum-functionality meter on the lines proposed in the draft report would be saleable only in Australia, and with some consumers choosing higher-functioning meters, could be expected to have an addressable market of only three to four million meters.

As a result, a minimum specification along the lines that AEMC has proposed is likely to result in:

(a) a relatively small price difference between full-function and low-function meters, due to the latter not being able to benefit from economies of scale in international markets (see also section (2) of this response);

(b) substantial replacement of low-function meters before the end of their useful lives, with the result that consumers will pay a lot more over time for metering services than they would if full-function meters were specified at the outset; and

(c) lower overall functionality of the installed base of meters, with the result that the market as a whole behaves less efficiently and prices to consumers are ultimately higher.

The result of this would be a material inefficiency in the markets for both energy and metering services, with consumers either overpaying for metering, or being unable to access the full range of efficient tariff options.

GE recommends that AEMC specify a single minimum specification for metering, replicating the existing national smart meter specification (which will attract international scale economies as described above). This will result in minimum long-term metering costs for consumers as well as maximising the medium-term efficiency of the energy market.

2) Indicative pricing for smart meters

On page 50 of the draft report, AEMC attributes to "industry sources" its claim that the price of a smart meter including communications module runs from AUD$250 to AUD$400, before installation costs, depending on the number of metering elements. GE is unaware of the basis on which this has been calculated, or whether it includes related expenditure such as back-end software or integration with enterprise systems such as billing.

GE recommends that AEMC revisit these cost assumptions. As with any mass-produced device, costs per unit are driven primarily by order volume (and to a lesser extent by other factors like functionality). GE submits that prices for residential meters[2] with a GPRS wide-area communications module, for order volumes in the 100,000 unit range for Q2 2013 delivery, will range from AUD$130 to AUD$250. The price within this range depends on the number of metering elements; given that the number of meters at the higher price points is relatively quite small, the weighted average cost per unit should be close to the lower end of the range. GE anticipates that these prices will fall over time, and particularly will be lower if order volumes increase as a result of economies of scale. This is why a single meter specification is important. If vendors need to produce multiple meters for low-, medium- and high-spec customers, unit costs will increase.

3) Other issues relating to smart meters

In addition to supplying meters, GE is Australia's leading supplier of distribution management systems and geospatial information systems. GE also has a substantial presence in the market for energy management systems (used by transmission utilities), as well as other types of network automation products and services.

Based on this experience, GE considers that there are substantial network benefits to the availability of smart meter data. For example, end-of-line voltage sensing can be useful in understanding when certain network operations need to be undertaken (such as changing tap settings or re-balancing between phases). Smart meter data become particularly important for efficient network investment in the context of widespread distributed generation. If DNSPs are able to access this information, it will allow them to optimise both capital and operating expenditure, with consequent benefits to consumers.

[2] Assuming current national smart metering programme specification.

As a result, GE recommends that:

(a) The minimum meter specification should include:

i. current, voltage and power factor measurement;

ii. outage identification;

iii. capability for over-the-air software upgrades. Even with a basic smart meter, much of the relevant functionality resides on software within the device. Over the life of the meter, there are many reasons why this would need to be updated: updating business rules around tariffs within the meter (for example, to support a new product offering by a retailer, such as pre-paid or load control); ensuring availability of the latest functionality; optimising access for third-party data services; and fixing bugs. Without over-the-air upgrade capability, the upgrade must be done by someone driving around and visiting each meter personally. An over-the-air upgrade costs cents; an update by a technician costs tens of dollars. As a result, including over-the-air upgrade capability (which is not expensive) will maximise consumers' access to the latest functions of the meter, which will better support retailers' latest product bundles. This will also improve compliance of the deployed meter base with rule changes that AEMC may wish to introduce in future;

iv. support for tariffs that may be partly or wholly calculated based on maximum demand;

v. access to standards-based home-area network (HAN) functions, including standards-based load control. This will be necessary to support any tariff plan that differentiates a load on a specific device (such as an air conditioner, pool pump or EV); and

vi. remote connect/disconnect capability. First, remote disconnection enables an isolation point for photovoltaic or other embedded consumer generation, which is a safety issue for network service providers. In addition, anecdotal experience has been that connects/disconnects increased dramatically once metering was handed to the retailer. In cases where distributors controlled the meter, they often decided not to action disconnects because the costs outweighed the benefits (such as when the customer moves premises & requests a disconnect). Once the retailer controlled the meter (and carried the credit risk without facing the direct cost of the disconnect operation), the retailer has tended to demand a far higher number of disconnect operations. Including a remote disconnect function adds about $10 to the cost of the meter; GE modelling estimates that this would save approximately $60 (NPV) in metering field operations and improved collections over the life of the meter.

(b) DNSPs should be able to promptly access as much of this meter data as is required for the optimal efficiency of their network planning and operations. In particular, outage notification should be provided in as close to real time as distributor systems are able to handle[3].

4) Other technologies

GE has worked with customers around the world to model the impact of a range of technologies designed to optimise capital spending on the grid. We have observed that many of these technologies have substantial benefits across the energy value chain, not just within the distribution network.

Accordingly, the Rules should define DSP projects to include dynamic voltage management and power factor correction (in addition to other relevant technologies), and should facilitate investments based on the net benefits across the whole value chain, not just those in distribution.

In the absence of this clarity, DNSPs may feel compelled to prefer projects with certain but limited benefits in the distribution network, at the expense of projects with larger NPV across the total chain.

It is critical to ensure that the definition of DSP projects includes all possible technologies that could have a positive impact on the value chain. For example, conservation voltage reduction (dynamically managing transformer tap settings to keep voltage at the lower end of the regulated range) can allow DNSPs to reduce energy delivered; when enhanced via state-of-the-art load flow analysis, this can be done without affecting customer satisfaction. To do so has benefits at the distribution level, by deferring spending on network infrastructure, but also has substantial benefits through reducing capital and operating expenditure on generation.

Based on GE Energy's understanding of the current Rules, the attractiveness of such projects is reduced by (a) inability to monetise benefits outside the distribution sector and (b) revenue foregone as a result of the reduction in energy sold.

As a result, any amendment to the Rules which is aimed at encouraging energy efficiency and DSP should be drafted broadly enough to cover DNSP investment in any NPV-positive project which will optimise spending on network upgrades (specifically including CVR and dynamic power factor correction[4]). GE Energy's financial modelling, which has been validated in collaboration with Australian DNSPs, indicates that there are substantial benefits to the energy value chain from deployment of IVVC at the 11kV/22kV level on Australian distribution networks.

GE Energy does not express an opinion as to the most effective way for such projects to be incentivised, such as whether benefits outside the distribution network are best recognised through the spot market or through the AER mechanism. DNSPs are better placed to comment on the optimal mechanisms for achieving the outcome.

[3] GE understands that in New Zealand, services such as this may be offered as a value-added service by metering services providers.

[4] These technologies are collectively referred to as "Integrated Volt-VAr Control" (or IVVC). We note that IVVC is currently being trialled by Ausgrid at Nelson Bay, as a part of the Federal Government's *Smart Grid, Smart City* project. Initial results have been positive.

5) Availability of information

Based on GE's experience in other markets, we consider that information on the operation of distributed generation and demand response projects should be available to all affected market participants in a timely manner. This will allow participants to better manage the unintended impacts of the deployment of these technologies, resulting in mitigation of potential adverse effects as well as higher ultimate penetration of distributed generation and demand response.

Side-effects of demand participation projects could have a substantial negative impact on the energy market if they are not appropriately managed. In particular, GE's modelling and experience elsewhere in the world indicates that demand response events often trigger a "post-peak" (and sometimes also a "pre-peak") around the event itself. For example, if consumers switch off air conditioners for two hours at 3pm in response to a demand event initiated by a retailer in response to market energy prices, those air conditioners are all likely to be switched back on at 5pm – running at maximum capacity – as consumers try to cool their homes down again. The market peak (felt by the retailers) would thereby have been avoided, but GE's modelling indicates that the resulting "post-peak" is likely to actually exacerbate the *network* peak (felt by DNSPs). As a result, it is important for NSPs to have maximum visibility of market-driven DSP events (including estimated pre- and post-peaks), and for retailers to have visibility of network-driven DSP events.

The need for NSPs to access this information (for use in distribution management systems) will increase as aggregators and retailers manage larger volumes of load. In particular, the restoration of those loads is likely to become an increasing issue for NSPs (particularly DNSPs), because the restoration of a large volume of load in a short space of time can have serious consequences for network system integrity (including voltage and frequency)[5].

In the short term, it is foreseeable that these system integrity issues could be severe enough to trigger network overload protection, with the result that thousands of affected customers would be cut off from supply. In the medium term, DNSPs may feel that the only course open to them is to install *increasing* network capacity to cope with the resulting instability, which is the opposite of the effect AEMC is seeking to achieve.

As a result, AEMC may wish to consider the situation where DSP activity by market participants has an adverse impact on system stability which could push up capital investment by network providers. Where this is the case, there would ideally be a mechanism by which the market can operate to prevent the adverse impact on the network, and preserve the efficiency of outcomes for consumers.

As a result, measuring and managing this is likely to lead to greater realisation of the benefits of the relevant technologies. In addition to the examples above, giving DNSPs prompt or real-time access to information about distributed generation (such metering of DG and its impacts on

[5] This is because most loads have a startup current which is substantially greater than the operating current for that load. The aggregate of many startup currents, such as when a large number of DSP customers restore loads at the end of a DSP event, has the potential to create an enormous local or system-wide peak. For this reason, load-control systems currently used by DNSPs (primarily hot water load control in New South Wales and Queensland) feature randomised startup for affected loads across an extended time frame (around fifteen minutes). State-of-the-art demand response management software, integrated with distribution management systems, also has this capability.

power quality, voltage and other factors) would allow them to run load flow modelling with greater accuracy, thereby increasing the efficiency of distribution network operations as well as improving the effectiveness of capital planning.

6) Existing load control activity

GE currently provides (or is implementing) distribution management systems to DNSPs covering a majority of the connected endpoints in Australia. From this point of view, we are aware that many Australian distribution networks rely heavily on existing load control schemes that have been in place for decades (such as residential off-peak hot water in New South Wales and Queensland[6]). These systems are not mentioned in AEMC's draft report. Given their importance to network security, GE recommends that AEMC consider how best to ensure that the benefits of these systems continue to be available to consumers.

These systems control substantial volumes of load (well over a gigawatt at the peak on the NEM). The affected networks are sized on the assumption that this load control will continue to be available to the DNSPs. Loss of this controlled load would negative that assumption, requiring the network to build additional capacity in affected areas. Of course, this runs counter to AEMC's goal of moderating network investment.

In the short term, other market participants are unlikely to replicate the controllable load which these existing systems control. As a result, AEMC may wish to consider arrangements to ensure that networks (and therefore consumers) are not deprived of the benefits of this load control. The current technology requires audio-frequency load control ("AFLC") receivers within the meter; we note that AEMC's draft specification does not require this feature[7]. Incremental replacement of AFLC-capable meters will therefore steadily diminish the volume of AFLC controlled load unless arrangements are made to counteract this[8]. Organisationally, these programmes rely on customer outreach conducted by DNSPs; if that outreach is affected by AEMC's proposed rule changes, volumes of controlled load may likewise erode. GE recommends that AEMC consider the impact of the proposed rule changes in the period between implementation and when networks are able to achieve similar load control through other means.

In summary, GE recommends that AEMC:

- **specify a single minimum specification for metering, replicating the existing national smart meter specification;**
- **revisit the cost assumptions for smart meters published in the draft report;**
- **set a minimum specification for metering which includes the functionality for:**
    - **current, voltage and power factor measurement;**

[6] Given that hot water load control has a limited ability to affect a summer network peak, most of these DNSPs recognise a need to access analogous load control on other appliances.
[7] GE has not requested that this feature be included in the minimum metering specification, because similar functionality can be achieved through the HAN features that we have requested.
[8] We note that currently, in New Zealand, metering service providers make AFLC functionality available to DNSPs for a fee; they are currently considering whether the same can be done via HAN, eliminating the expense of the AFLC relay. For current purposes, the important thing is that the DNSP's ability to control the load is retained.

  - **outage identification;**
  - **over-the-air software upgrades;**
  - **access to standards-based home-area network (HAN) functions; and**
  - **remote connect/disconnect capability;**
- **provide for DNSPs to have access to information about DSP activities which will enable them to calculate the effects of those DSP activities on system security, and to provide feedback to market participants in a way that ensures that system security is maintained with minimal additional capital spending; and**
- **provide for interim arrangements that ensure that the benefits of existing DNSP load-control programmes continue to be available to DNSPs (and, by extension, consumers).**

GE would welcome the opportunity to provide AEMC reviewers further information or clarification. Please contact GE Government Affairs and Policy Director (Australia and New Zealand) Kirby Anderson on (07) 3001 4339 or kirby.anderson@ge.com.

Yours sincerely

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