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Claire Richards
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Our Ref: JC 2017-043 1 December 2017

Dear Claire,

S&C Electric Company response to the Issues Paper on the Frequency Control Frameworks Review (EPR0059)

S&C Electric Company welcomes the opportunity to provide input into the Issues Paper on the Frequency Control Frameworks Review.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports "wires and poles" activities but has delivered over 8 GW wind and over 1 GW of solar globally. S&C Electric Company has been actively engaged in deploying Battery Energy Storage Systems for over 10 years, supporting a full range of business models and using a range of battery technologies, at the kW and MW scale, and currently has 76 MW/189 MWh in operation. In Australia, S&C projects include the Ergon Grid Utility Support System in Queensland, which reduces peak loads and provides voltage support on rural Single Wire Earth Return lines and the 2 MW battery for PowerCor in Victoria.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further support to the Australian Market Energy Commission on the treatment and potential of these technologies.

Yours Sincerely

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General Comments

Inertia is not a Selective Service

If a synchronous generator is connected to the system and operating, then they will be providing inertia, whether they intend to or not. For this reason, inertia provision and primary response should be a mandatory services and the issues around deadband settings need to be resolved and a mandatory requirement to deliver frequency support, within specific deadband settings, is likely to be the best route to delivering frequency control at least cost. If there is still a shortfall in "inertia" then the requirement for an inertia market should then be reviewed, but it would be preferable to create a "frequency control service", which is technology neutral, rather than an "inertia" service, which is not.

Obligations on Renewable Generators

Newly connecting non-synchronous generators are currently being required to provide some sort of frequency response as part of the technical requirements for connection. If AEMO and AEMC are going to require (mandate) frequency control from non-synchronous plant, then it would be consistent to require the same technical delivery from synchronous plant.

If any new mandated frequency service is remunerated, then non-synchronous generators should also be remunerated for any services they provide.

Location is important

AEMO currently procures lowest cost frequency services to support the system and deliver value to the end consumer. However, this has resulted in occasions when a single region is delivering frequency support to the entire NEM. It would seem prudent, particularly in light of the requirement now placed on TNSPs to support inertia in their regions, that while lowest cost is important, adequate provision of frequency in all regions should be ensured.

Short Term Operating Reserve

One of the concerns for maintaining frequency is the issue of ramping as demand and or variable generation vary. This is particularly true for the loss or return of rooftop solar as a cloud front passes, or on the boundary of operation, at various wind speeds, for wind turbines. Managing ramping requires fast response, flexible resources and this may be better secured as a distinct new service, rather than trying to manage through frequency control services.

Black start from Aggregated DERs

The AEMC states that SRAS (black start) can be delivered by distributed resources. We would be grateful if the evidence that aggregated small-scale resources can deliver a grid-forming service, that supports synchronization, could be shared.

Large-scale single batteries of a capacity of greater than 30 MW have demonstrated an ability to deliver black start in Europe and the USA, but we are not aware of any aggregated small-scale systems that have successfully delivered black start.

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Response to Questions

Question 1 Scope

Are there any other issues relating to frequency control that should be included within the scope of this review?

The scope of the review is well-framed. Frequency control will come with a cost, whether it is mandatory or a market service. These costs need to be assessed.

Question 2 Drivers of degradation of frequency performance in the NEM

(a) Do stakeholders agree with the drivers of the observed long term degradation of frequency performance as identified by DIgSILENT?

Yes

(b) Are there any other drivers of frequency degradation in the NEM that are not mentioned here?

FCAS and the AGC are not designed nor capable of delivering inertia and primary response. The AGC is too slow, taking 30 seconds to respond to a frequency issue. Inertia is immediate and primary should follow contiguously.

Question 3 Materiality of frequency impacts from non-dispatchable capacity

(a) What are the likely impacts on frequency of increasing proportions of non-dispatchable capacity, and reducing proportions of scheduled generation?

Currently, even with withdrawals, there is sufficient *potential* inertia and primary response in the NEM (although it is not evenly or useful distributed through the regions), but that *potential* inertia is not being provided. Some inertia is being provided, but it is rapidly damped by either governor control or AGC signals.

If operational priority is given to frequency support (rather than energy dispatch), then those plant that can deliver frequency support should be designated "must run" plant, with their energy prioritised as a result. In GB "must run" large combustion plants are prioritised over all other generators, bar (a) nuclear, which is deemed to be inflexible and (b) solar PV, which is deemed to be un-constrainable. This means that in summer at midday, when minimum demand due to distributed small-scale solar PV is an issue, wind is constrained off. Wind is a highly flexible generator and can be paid for this service.

The issue is determining the minimum required amount of frequency support and its associated energy output and then building up generation around that amount.

(b) Are there any significant impacts on frequency that may occur from changes in output from individual large scale semi-scheduled generation (large solar and wind farms)?

System security only becomes an issue when forecasting of wind is either at the low wind speed threshold (some output to no output) or at the cut-out wind speed threshold (maximum output to no output). Accurate weather forecasting should enable accurate management of the wind fleet. National Grid

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quotes an accuracy of forecasting for wind of >94% and also has the ability to call on wind to provide flexibility (when generating).

(c) Does the analysis for wind generation above hold true for large scale solar PV? Does large scale solar PV output change more rapidly than wind output? Are changes in solar output more difficult to forecast?

Wind forecasting is relatively more straightforward. Forecasting of solar insolation is also very straightforward, but clouds complicate solar generation and are very difficult to forecast. There is an active team at the Bureau of Meteorology looking at forecasting for solar project development and forecasting of generation output. The former is a little easier as it can be based on historical data, both from the Bureau's surface radiation network and analysis of satellite images. Forecasting of generation output (future) is complex and computationally demanding. It is based on satellite imagery and numerical weather prediction techniques.

There are researchers working on predicting clouds and cloud fronts (latter would be easier to predict), but it's not clear whether these forecasting tools are operationally ready (Ian Grant, at the Bureau of Meteorology, Melbourne, would be a useful contact). Aviation weather also requires a good understanding of clouds and it is possible that some combination of the forecasting used for aviation and the forecasting used for solar generation could yield a useful forecasting product for AEMO, but collaboration is needed between the two national agencies to develop the tools needed.

Observations from surface networks are vital to "ground-truth" satellite data, but are costly to maintain (see details of the ground network here: http://www.bom.gov.au/climate/data/oneminsolar/stations.shtml, noticing the changing number of stations). It may be useful for the Bureau to work with solar developers to extend and support the network, plus improve forecasting.

We also note that renewable generators deploy their own meteorological equipment and because income is highly dependent on generation output, they do their own forecasting (or contract for forecasting services), which is probably not shared with AEMO. Therefore, it seems beneficial for large-scale renewable generators to collaborate with AEMO on developing forecasting tools.

There are other approaches, including a combination of known generation output (particularly at the rooftop scale) and weather forecasting to help track the movement and development of clouds over urban areas. This would give a now-casting to forecasting capability, which is probably better than no forecasting.

This is certainly an area that needs significant work, since accurate forecasting of solar output would make managing the NEM very much easier.

The addition of batteries at the domestic-scale will complicate the forecasting of solar PV generation considerably, since a fleet of batteries will all be in different states of charge and will reduce export until fully charged, before the solar generation reappears on the system (as negative demand). The battery register may help, but compliance in adding an installation to the register may be difficult. Certainly any battery that wishes to participate in the market should be registered.

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Question 4 Drivers of change

Are there other drivers of change affecting frequency control that are not set out in this section? If so, how material are they?

Frequency control is the balance of generation with demand. The review has a major focus on generation, but, other than a brief discussion of DER, doesn't assess the impact of demand. Is changing demand (forecasts) or responsive demand something that is within scope? Is forecasting demand becoming more challenging? Are any issues with forecasting demand largely the result of distributed rooftop solar (seen as minimum demand) or are there other factors that are impact on the ability to predict demand? Or are all the issues only with generation forecasting?

Question 5 Assessment principles

(a) Do stakeholders agree with the Commission's proposed assessment principles?

Yes

(b) Are there any other relevant principles that should be included in the assessment framework?

AEMC has already mandated particular approaches for newly connecting non-synchronous generators. Meeting these mandatory requirements may require additional investment, without the opportunity to earn an income when a service is provided. All connectees should be treated fairly and equitably. If frequency control is mandated and remunerated for large-scale combustion plant, then system services provided by non-synchronous generators via mandated assets should also be remunerated.

Where a system support service cannot be delivered by a connectee, then the connectee (particularly an established connectee, rather than new connectee) could purchase that service via a market.

Question 6 Assessment approach

Are there any comments, or suggestions, on the Commission's proposed assessment approach?

No

Question 7

Are stakeholders aware of any other costs or impacts linked to the degradation of frequency control performance in the NEM?

Other than those articulated at the recent (28 November) AEMO Ancillary Services Technical Advisory Group and those detailed in the DIgSILENT Report, no.

Question 8

Are there any other risks that stakeholders are aware of with respect to degradation of frequency control as represented by the flattened frequency distribution within the normal operating frequency band shown in Figure 5.1?

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As of 28 November (AEMO AS-TAG), it appears frequency is now outside the NOFB for more than the allowable time. This would suggest the problem is deteriorating. AEMO are no obliged to take action to correct frequency issues. Frequency control may still be within the bounds of the FOS (but perhaps we are now straying outside the FOS), but if the FOS is no longer delivering the control required in the NEM, then this suggests the FOS needs updating. It would not be sensible to sit back and do nothing, just because it appears we're meeting a particular standard.

Question 9

Are stakeholders aware of any other international experience in relation to primary frequency control that is relevant for this review of frequency control frameworks in the NEM?

The recent tightening of deadbands in the Texas (ERCOT) in response to the increasing penetration of variable generation.

The wholesale overhaul of system services in the Northern Ireland-Ireland (EirGird-SONI) system to accommodate the increased penetration of renewable generation, mainly wind, but solar PV is expected to grow.

The review of system services, including a review of frequency services, in the GB system by National Grid (https://www.nationalgrid.com/uk/electricity/balancing-services/future-balancing-services, see "SNAPS").

Question 10 Mandatory primary frequency control

(a) What are the advantages and disadvantages of mandating primary control for all generators in order to improve frequency control during normal power system operation?

Inertia and primary frequency response are near-immediate responding services. They cannot be signaled by the AGC. Plant appear to provide (limited) inertia regardless of deadbands and governor settings. If plant is connected to the system, it will provide inertia and possibly some primary response. It therefore seems appropriate that all connected and operational synchronous plant is uniformly asked to provide inertia and primary response and the most appropriate mechanism to ensure all plant is involved is a mandatory requirement.

The mandatory requirement should be valued (remunerated). Examples of remuneration can be found in the Monthly Balancing Services Summary reports from National Grid (https://www.nationalgrid.com/uk/electricity/market-and-operational-data/system-balancing-reports). See https://www.nationalgrid.com/sites/default/files/documents/MBSS_Sep_2017%20V2.pdf for the September report. Prices for Mandatory Frequency Services are on pages 12-13, with commercial frequency response on page 14. There is a useful summary table on page 36 that details the spend on mandatory Primary, Secondary and High, the total spend on availability (holding) and utilisation (energy).

(b) What factors should be considered in the specification of a mandatory primary frequency control response?

No comment. Perhaps review the mandatory requirements from other jurisdictions (e.g. GB Grid Code).

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(c) Are there any regional issues that should be considered in assessing whether primary frequency response should be a mandatory obligation for registered generators in the NEM?

Currently, frequency control is procured at lowest cost, with no requirement for an appropriate distribution of FCAS (other than the newly imposed limits on FCAS from Tasmania). It would be sensible to assess and determine a minimum level of inertia and primary frequency response required for each region. AEMO will be undertaking this assessment anyway, as part of the new requirement on TNSPs to support a minimum level of inertia. The TNSP requirement cannot be viewed in isolation to the Frequency Control Framework Review. A holistic assessment is likely to deliver system stability at lowest cost. Perhaps the TNSPs need to provide a "top up" inertia service, with an opportunity to explore new technologies as part of their approach, since "baseline" inertia and primary response will be mandated via AEMO.

(d) Should an obligation for generators to be responsive to changes in system frequency outside a pre-defined dead band include a required availability reserve, such as 3 per cent of a generators registered capacity, as is the case in Argentina?

No comment.

Question 11

What are the advantages and disadvantages of procuring primary control through bilateral contracting as a means to improve frequency control during normal power system operation?

Are the details of bilateral contracts publicly available? If not, then it would be preferable to avoid bilateral arrangements and go through the market (e.g. National Grid's commercial frequency response holding).

NOTE: National Grid's commercial frequency response costs £7.47M for 418 GWh versus £1.8M for 293 MW Primary, 165 MW Secondary and 331 MW of High mandatory frequency response (see https://www.nationalgrid.com/sites/default/files/documents/MBSS_Sep_2017%20V2.pdf).

Question 12 Market based options for primary frequency control

(a) What are the advantages and disadvantages associated with the two options presented for earlier provision of primary frequency control:

(i) Using the existing contingency FCAS for provision of primary frequency control and narrow the normal operating frequency band to trigger a primary frequency response closer to 50 Hz.

FCAS and the AGC are not able to accurately deliver inertia or primary frequency response in a timely manner.

(ii) The establishment of a new primary regulating service to provide primary frequency control within the normal operating frequency band, separate from contingency FCAS.

This would be preferable as it would allow the specification of a new service to best meet system needs and it would need to be an automatic response, rather than signalled.

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Question 13

Are there any aspects of the existing Causer pays procedure that stakeholders believe are acting to discourage the voluntary provision of primary frequency response?

There is a perception that wide deadbands limit “Causer Pays”, however DIgSILENT and AEMO have shown that plant with tight deadbands have lower “Causer Pays” liabilities. It seems there is some work to be done on convincing potential inertia and primary response providers that responsiveness reduces “Causer Pays” liabilities.

Question 14 Frequency monitoring and reporting

(a) What are the potential benefits or costs associated with a requirement for AEMO to produce regular frequency monitoring reports?

AEMO should certainly be monitoring frequency control in the NEM to ensure that frequency is within the NOFB and that the FOS (or any amended FOS) is being met. It would be useful to know on a monthly basis how much was spent on maintaining frequency within the NOFB (e.g FCAS costs) and if standards were met or not met. The cost information is similar to the Monthly Balancing Services Summary provided in the UK, by National Grid for the balancing of the GB system and is also useful for current and potential new market participants in determining the opportunities for providing a service.

Presumably, cost data and whether standards were met/not met (how often did frequency stray outside the NOFB?), are needed internally, so the cost would be presenting that data in a useable public form.

(b) What metrics should such frequency monitoring reports include?

Cost of inertia and frequency services; whether the FOS was met/not met and an assessment of how well frequency was maintained within the NOFB. It may be helpful to provide a regional breakdown of data, if there are significant differences between regions. The regional data would also be a beneficial signal to the industry on where such services are needed (valuable).

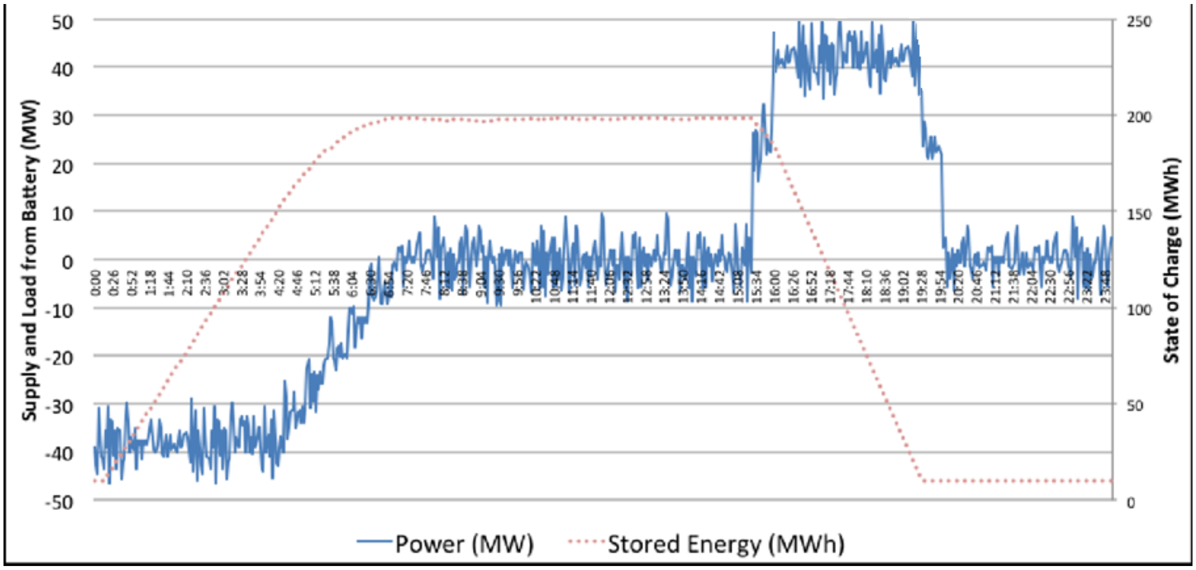
Question 15 Defining FFR

What are your views on AEMO's advice on how and when FFR might emerge in the NEM?

Fast Frequency Response (FFR) is being delivered in a variety of jurisdictions. Where an FFR service is developed or valued, it is largely served by batteries and currently only Lithium ion batteries. Where accuracy is valued, as well as speed of response (e.g. the original PJM Reg D signal), this increases participation, noting that there is a finite amount of FFR available/needed (batteries “eat” their own opportunity). Prices for FFR services, such as the Enhanced Frequency Response service in the GB system, are typically lower than for primary services.

Batteries can deliver all or nothing, so essentially a vertical line for ramping. They can also provide considerable flexibility in the “shape” of any response and can the speed and shape of any response easily be adjusted (e.g. Kilroot 10 MW battery, Northern Ireland).

Batteries can also provide capacity and frequency simultaneously:



Battery continuously delivers frequency support, while charging and discharging (red dashed line) and delivers capacity from ~1600 to 1930.

Batteries also provide grid-forming capabilities (islanding mode) in micro-grids and this is being demonstrated at a number of locations globally. Utility-scale batteries are also providing black start capabilities in the USA and Europe.

FFR should be developed as a new stand-alone service (outside of FCAS and AGC) and should respond automatically to measured system frequency, in order to deliver sub-cycle responses. The potential of FFR should be explored (and is being explored) in trials, ahead of more routine deployment. Care is needed as a large battery in one region/system, may have different impacts and need different operational parameters in another region.

FFR should only be developed as a new service (excluding trials, which are needed to understand how FFR might act in each region – this could be part of the TNSP requirement/role), once all issues with inertial and primary response from currently connected synchronous generators has been resolved. If current synchronous generators return to providing primary frequency response and sustained inertia (undamped by station controls), this will modify the amount of FFR required. Priority should be given to existing assets, as this is likely to deliver frequency control at lowest cost (although this dependent on any likely price for a mandatory and/or commercial service).

The Kilroot 10 MW battery in Northern Ireland sits behind the connection of a coal and oil power station and the primary purpose of the battery is enable the thermal plant to run efficiently. A great deal of attention has been given to the partnership of renewable generation with batteries, but there may also be beneficial partnerships between batteries and large-scale combustion plant.

Question 16 Potential options for making changes to FCAS frameworks

What are your views on the above indicative approaches to varying the design of FCAS services, and on other potential changes?

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It would preferable to develop the new service outside FCAS.

Question 17 Technical characteristics of emerging sources of FCAS

What other emerging sources of FCAS should the Commission be aware of?

Wind is already covered.

Frequency control by Demand Management and footroom (increasing demand, Demand turn up service in GB) are other services that may help support the system.

Question 18 Managing the frequency impacts of non-dispatchable capacity

(a) Is the existing FCAS framework sufficient to maintain frequency as greater proportions of non-dispatchable capacity enter the power system?

No.

(b) Would it be more efficient to improve the forecasting of non-dispatchable capacity to reduce imbalances in supply and demand, or to rely on higher levels of regulating FCAS to manage those imbalances?

Forecasting non-dispatchable capacity is likely to be challenging, particularly for solar-dependent generation, and unlikely to be achieved in the timeframe needed to address incidents where frequency is outside the NOFB. Forecasting of demand and generation is essential to deliver system balancing at lowest cost, so forecasting does need to be improved, but we have a significant and pressing issue in maintaining frequency within the NOFB now (AEMO are obliged to take action).

It would be preferable to ensure that the potential inertial response and primary response currently connected to the system is delivered.

(c) What other efficient options are there to manage imbalances in supply and demand resulting from the variability of non-dispatchable capacity within the five minute dispatch interval?

Other jurisdictions have Short-Term Operating Reserve (slower than 5 minutes: https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/short-term-operating-reserve-stor) and Fast Response/Fast Reserve (e.g. https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/fast-reserve) services to support fast ramping of demand.

Question 19 Cost recovery arrangements

(a) Do you consider existing cost recovery arrangements for contingency FCAS to be appropriate?

Current arrangements seem to cause a great deal of angst.

The cost of FCAS, particularly regulation, has increased significantly and yet frequency control is steadily deteriorating. This means providers of the service are not delivering the service they are being paid to

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deliver. It is critical to assess whether paid participants are actually delivering the required service and if not, take action to ensure that participants are only paid for what they actually deliver.

(b) If not, how should cost recovery arrangements be changed?

No Comment.

Question 20 Co-optimisation with other markets

(a) Are there other system services, such as inertia, system strength or system stability, that should be co-optimised with FCAS markets?

System services are inter-related. A holistic assessment of system needs is required to deliver system security at lowest cost.

System security (frequency) should be prioritised over energy dispatch and delivering other services.

Other jurisdictions require mandatory frequency response (e.g. GB Grid Code), and this takes priority over other activities, but does not prevent the delivery of energy.

(b) If so, can one service (such as inertia) be optimised first and, if so, why?

Inertia and primary response need to be a mandatory services for relevant connectees. These services need to be paid for and performance needs to be monitored to ensure that the "system" receives the service "it" (end consumers) pays for. Inertia and primary response need to have priority over other services/dispatch.

See earlier comments on "must-run" plant that have priority for frequency/system support, but also provide capacity (that is, they must be on the system and their energy dispatch takes priority over other generators, since system support is vital).

(c) Would co-optimisation impact on cost recovery and, if so, how?

Not sure, but there may be cost-efficiencies.

Question 21 Consistency in the provision of system security services

To what extent is it important that the NER arrangements for the provision of system security services are consistent between providers of such services, e.g. large, transmission-connected generators and distributed energy resources?

Inertia is not a service that small-scale DERs could ever provide.

Question 22 Frameworks for the connection and operation of distributed energy resources

(a) Do the existing connection frameworks inhibit the ability of the owners of distributed energy resources to provide system security services?

DER connectees do not face the obligations placed on larger-connectees who are active in the NEM. DERs do cause system issues at both the distribution and transmission (NEM) level, but currently connection is

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free and must be supported by the DNSPs and export is free as no network charges are levied on small-scale DERs regardless of the impact such export may have the on distribution network or the wider system. As such, DERs currently have carte blanche to connect and it is difficult to see how DER connectees can be motivated to minimise their impact on the system.

(b) If distributed energy resources are to play a bigger role in supporting power system security, would it be more appropriate for the distributed energy resources to be required to provide system security services, or to be incentivised to provide them?

Distributed Energy Resources (DERs) should be incentivised to provide the limited number of services that they can technically provide. DERs can be incentivised via tariffs and network charges. However, the value of a service to the system from a small-scale asset may not be sufficient motivation for the owner of the small-scale asset.

Distribution system services from domestic customers in the UK, were valued at £50 per year per household, for 15 events, involving full control of all domestic appliances (fridge, and wet appliances). Frequency services from full control of the charging of electric vehicles (EV, but not directly accessing the battery) were valued by National Grid at £25 per year per EV. Various projects in the UK show remarkably consistent values of around £40-70 per year for a full range of automatically (no choice) provided services, this represents 10 % of the average electricity bill. None of these services take account of the impact on the asset of delivering a particular service and there is a range of research that shows the use of domestic-scale batteries and EV batteries has a negative impact on the life and capacity of the battery, that is not valued by the payment for any service.

(c) Are there any other regulatory barriers or opportunities relevant to the provision of system services via distributed energy resources that are not discussed in this section?

No Comment

Question 23 Frameworks for distributed energy resources to participate in the NEM

Are there any other regulatory barriers or opportunities relevant to the provision of system services via distributed energy resources that are not discussed in this section?

Distributed energy Resources (DERs) cannot provide inertial response and are unlikely to provide primary response. This is particularly true of small-scale (domestic) assets that would have to be aggregated together. Aggregation takes time and non-response (unavailability) has to be allowed and addressed. Frequency control on longer timescales (e.g. secondary) may be possible.

Large-scale DERs, of a sufficient size to deliver a meaningful response as a single asset, such as C&I batteries or demand response (likely to be 3-5 MW minimum), may be useful resources for system support and dependent on the asset (e.g. battery), may be able to provide a primary response.

It cannot be assumed that all DERs, regardless of size, can deliver a frequency service. DERs are primarily deployed to manage energy costs, therefore any DER will always be prioritised by the owner (operator) to maximize benefit to that owner (operator). This customer benefit may be contrary to the system benefit.

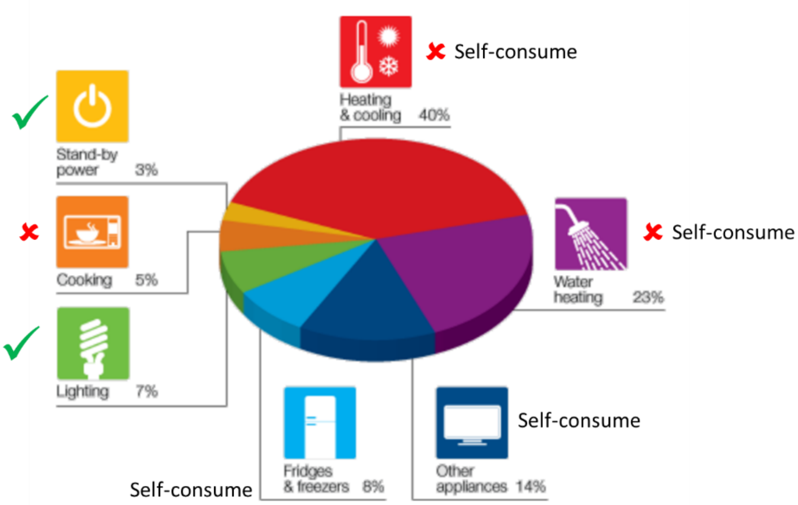
Question 24 Technical challenges

(a) Is the aggregated capability of distributed energy resources sufficiently 'firm' for aggregators to provide the system security services that AEMO needs?

No. Studies in the UK (Low Carbon London, UKPN) show that domestic demand response from those enabled (who had agreed to provide a response) was 24%. This means that to deliver 1 MW of firm response, 4.2 MW must be held to allow for non-response. The project also showed that engaging domestic customers and keeping them engaged in a programme to support the network (to avoid reinforcement, rather than provide frequency services) was time consuming and expensive (of the order £2000-4000 per kW of service. The higher value includes the cost of equipment to enable the service). The project demonstrated that it was far easier to find a single C&I load to meet the required response, then attempt to engage, maintain engagement and manage non-response from domestic customers.

Any aggregation will increase the time between a signal to respond (change in frequency or AGC) and delivery of any response. This means that aggregated resources could not deliver inertia or primary response. A secondary service may be possible. Frequency Control by Demand Response is a service that is provided by aggregators in the UK, but is restricted to large single users, rather than many loads aggregated together.

The reality is, that when the energy use of a household is examined, the bulk of the energy needs are thermal. These thermal needs cannot be addressed by a battery.



This along with wider research indicates that:

i. batteries do not yet represent value for money for households, even with solar PV;

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ii. The payback period is longer than the lifetime of the batteries and much longer than the lifetime of some critical components (e.g. inverters);
iii. Self-consumption, using delayed start, thermostats and energy management software is a more cost-effective solution to maximising use of rooftop generation;
iv. The provision of services has a negative impact on the lifetime of the battery;
v. The value of a service to the system, may not be a sufficient motivator for or adequately compensate (for the impact of not having access to their asset or the damage the service may have on the asset) the householder.

(b) Are there any other technical challenges relevant to the provision of system services via distributed energy resources that are not discussed in this section?

Frequency control is typically a rapid response service required by the transmission system or the wider NEM. Orchestrating large number of DERs may present technical operational issues to the DNSP, in terms of thermal/voltage management, of transmitting a frequency service over the distribution network to the wider system. This will have impacts and costs. DERs may be able to provide locational services to DNSPs, that provide greater benefits than providing a system service to the NEM.

The loss of advanced metering data, through recent rule changes, limits the monitoring capability of the DNSPs.

Question 25 Commercial challenges

Are there any other commercial challenges relevant to the provision of system services via distributed energy resources that are not discussed in this section?

While the potential capacity of aggregated resources may be significant in system terms and the total value that the aggregated portfolio can earn by providing services may be significant, the value to each individual participant is likely to be very small (see response to 22b). If at the un-aggregated level, the value to each individual provider is small, the value (income) may not be sufficient to motivate or engage participation.

It is possible to encourage system-friendly behaviour from DERs through tariffs and network use charges. These are likely to be scalable and support a locational signal, in a way that an AEMO driven service or market would not. For instance, if the use of a network at midday in summer to export rooftop solar PV was more costly than to export at evening peak, this would be likely to incentivise self-consumption or storage at midday, with storage allowing later use at peak (or export to the wider system at peak), supporting peak management of, say, air conditioning load.