Registered Office:
Newington House
237 Southwark Bridge Road
London SE1 6NP

Registered in England and Wales No: 3870728

Company:
UK Power Networks
(Operations) Limited

Lia Santis
Ofgem
9 Millbank
LONDON
SW1P 3GE

15 December 2011

Dear Lia

Smart Grids Evaluation Framework – A Smart Grids Forum Consultation Report

We are pleased to respond to the above consultation on behalf of our four distribution licence holding companies – Eastern Power Networks plc, London Power Networks plc, South Eastern Power Networks plc, and UK Power Networks (IDNO) Ltd.

This is an ambitious project in that it attempts to reconcile a wide range of inputs, the majority of which have no 'history' on which to benchmark assumptions. Nevertheless, in order for the modelling to be manageable and yet credible, we appreciate that a balance has to be struck between the need to simplify assumptions and the need for the scope to be sufficiently broad to capture the key value drivers and solution options.

On the whole we believe this balance has been achieved and our comments, while constructively critical, should be viewed as supportive of the approach while highlighting some important qualifications.

The output of this work will be helpful in providing an indicative high-level evaluation of smart grids from the perspective of future electricity load growth and low carbon technologies.

The work of Smart Grid Forum workstream 3 will provide a more comprehensive evaluation of technological and commercial solutions and a more granular appraisal of likely smart grid investments when it completes its work in 2012. We are therefore pleased to note that the model will be able to receive future, more refined inputs as they become available. We also believe that is important that other scenarios are considered that reflect the current uncertainty in market and legislative mechanisms meeting the UK's carbon commitments.

It will nevertheless be important to understand that, in reality, evaluation will be a continuous process as the levels of low carbon technologies increase, smart grid technologies mature, and the results of key research and deployment trials (such as LCNF projects) become available.

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We hope that you will find our detailed answers in the appendix useful and confirm that we have no objection to this letter being published on Ofgem's website. If you have any questions about our response, please do not hesitate to contact me.

Yours sincerely

Keith Hutton
Head of Regulation
UK Power Networks

Copy: Ben Wilson, Director of Strategy & Regulation and Chief Financial Officer, UK Power Networks
Dave Openshaw, Head of Future Networks, UK Power Networks
Paul Measday, Regulation Manager, UK Power Networks

Appendix

Section 2: Smart grid evaluation framework

Do you agree with our definition of smart grids?

The definition of smart grid (derived directly from the European Technology Platform for the Electricity Networks of the Future definition[1]) is adequate in the context of the evaluation framework, provided that the phrase 'efficiently deliver sustainable economic and secure electricity supplies' is considered from a 'whole system' perspective i.e. including generation, transmission and distribution. However, while the stated characteristics are typical, they are by no means exhaustive; and while they describe functionality, they do not describe the benefit of that functionality.

We also observe, with reference to the characteristics described in Section 2.1, that while the European Technology Platform for the Electricity Networks of the Future definition goes on to describe one of the characteristics of a smart grid as being to 'deliver enhanced levels of reliability and security of supply', this is not a characteristic which is explicitly described in the smart grid evaluation framework document. Indeed, the basis of the evaluation, as we understand it, is to hold quality of supply as a constant. We return to this point in our answer to the next question.

Have we captured the main complexities associated with assessing the costs and benefits of smart grids?

From an evaluation perspective, it will be important to understand the full whole system benefits that functionality (and hence investment) will deliver. For example, the statement under 'key challenges' in the Executive Summary (referring to decarbonisation and security of supply goals) that 'these goals can generally also be achieved through traditional reinforcement' might suggest that the evaluation is ignoring avoided peak (generally fossil fuelled) generation benefits that smart grids can deliver, and is instead constrained to evaluating only avoided network reinforcement benefits.

Avoided peak generation (through peak load shifting and/or more closely matching demand to low carbon variable generation) delivers not only 'carbon' benefits but also mitigation of spot price volatility, imbalance risk, and reduced reliance on part-loaded generation (or Open Cycle Gas Turbine plant) for residual balancing services. These are all 'avoided cost' opportunities which should be included in the benefits evaluation (or at the very least identified as significant non-quantified benefits).

While we understand the need to limit the number of variables when considering value options in relation to a counterfactual, we would observe that:

- increasing levels of dependency on electricity for heat and transport are likely to give rise to higher levels of expectation for reliability and security of supply in future; and
- since smart grids are in any case likely to deliver improved quality of supply as a consequence of higher levels of observability, controllability and automation, it would be a significant omission not to include such consequential benefits in the framework evaluation.

[1]European Technology Platform SmartGrids Strategic Deployment Document for Europe's Electricity Networks of the Future – Executive Summary:
http://www.smartgrids.eu/documents/SmartGrids_SDD_FINAL_APRIL2010.pdf

Do you agree with our approach to dealing with these complexities, in the overall evaluation framework, in particular:

We propose to take a two-stage decision tree approach, rather than relying on a conventional cost-benefit analysis framework alone. Does this constitute an appropriate approach, given the need to measure differences in the "option value" that different smart grid investment strategies provide?

Real-options is an appropriate approach to evaluation given the uncertainties over the form and rate of low carbon transition and its impact on electricity distribution networks. A conventional CBA approach would rely on assumptions which could not at this stage be substantiated and hence could provide misleading indications of the cost-effectiveness and value of any given smart grid development strategy.

However, we do not underestimate the difficulty in deriving reliable inputs to the modelling – for example future costs (both capital and operating) and asset lives (and hence depreciation rates) of as yet immature smart grid technologies i.e. applications currently with low 'technology readiness levels' (TRL). A further difficulty lies in determining the level of confidence that can be assigned to the credibility of the necessary simplifying assumptions. However, provided these limitations are acknowledged and, ideally, the level of confidence in the outcomes is broadly quantified, then we believe that the proposed approach is valid and should provide a useful indication of the relative benefits of options.

Do you agree that the year 2023 constitutes an appropriate decision point in our analysis?

2023 is an appropriate 'decision point' as it coincides with the end of the RIIO-ED1 period and broadly coincides with Smart Grid Forum Work Stream 3's initial conclusions as to the period during which a second, more advanced phase of smart grid evolution might begin to gain traction. However, the relevance of 2023 as a smart grid transition point clearly depends on future energy scenarios and assumptions regarding the scale and mix of low carbon technologies. Smart Grid Forum Work Stream 1's scenarios are now due and the relevance of 2023 under different scenarios should be reviewed in light of this input.

Section 3: Value drivers and scenarios

Do the technologies set out in Table 2 constitute a sensible list of value drivers?

Although we are concerned that some readers of the document might find the term 'value driver' confusing (i.e. a 'cost driver' that might increase the 'value' of a smart grid solution), we agree that Table 2 constitutes a list of smart grid value drivers that are likely to be relevant to the period out to, say, 2023. We would, however, question the practicality of projecting value drivers out to 2050 due to the inevitable degree of uncertainty over future policy, technological development and, not least, the degree of global warming and climate change being experienced. By contrast, Smart Grid Forum Work Stream 3's report has considered two time frames: from today to 2020 and from 2020 to 2030.

By 2050 it is conceivable that: fuel cells might prove a viable and economic source of energy (for example for private cars and commercial vehicles); currently unforeseen groundbreaking/ disruptive technologies might have displaced current approaches to electricity transportation architecture; and we might at least have begun a transition towards a 'hydrogen' economy.

Nevertheless, we agree that in the inevitable absence of robust evidence to the contrary, it is appropriate to consider scenarios that assume a status quo in terms of the range of viable evolutions of technology.

While the value drivers as stated are valid, we do have some concerns regarding the omission of other value drivers and technologies which we shall address in our following comments.

Do you agree with our assessment of the technical characteristics of each?

In terms of smart grid value drivers, we agree that Table 2 is broadly accurate in its assessment in terms of impact on peak demand load and voltage.

However, impact on fault level (which can be a significant smart grid value driver) is not a characteristic considered by Table 2; nor is impact on power quality (for example, due to inverters used in conjunction with PV installations or (future) V2G applications).

We suggest that large scale distributed onshore wind (or perhaps, more typically, concentrated clusters of onshore wind farms giving rise to DG-dominated networks) might also increase peak thermal load on distribution networks (for example the 33kV network, which is the focus of UK Power Networks' Flexible Plug and Play LCNF project). Moreover, as clearly illustrated in section 5.14 of the SEDG/Imperial College/ENA report 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks'[2] (referenced in the bibliography to the consultation – 7.5.2), large volumes of transmission connected wind generation could have a sufficiently strong market price-setting influence to drive future electricity demand peaks on distribution networks.

This same report also illustrates that heat pumps, when used in conjunction with a heat store (for example a hot water tank), can contribute significantly to the amount of demand that is flexible (see sections 3.15–3.19). Indeed, heat pumps used in very well insulated homes (for example, potentially post 2016 zero carbon homes) can be operated with greater flexibility due to the very slow degradation of in-home ambient temperature levels when the heat pump is not running.

Are there any other technologies that could have a significant impact on the value of smart grids?

Table 2 makes no reference to CHP/CCHP plant which, as well as potentially increasing peak demand, can also give rise to fault level issues, especially on urban networks. Conversely, CHP (and biomass) plant can, in some circumstances, be employed to provide network support. CHP plant used in conjunction with heat networks or a heat store can be operated more flexibly and hence provide greater (or more dependable) levels of network support, and hence in this mode is a potential 'value provider' rather than a 'value driver'.

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[2] http://www.energynetworks.org/electricity/futures/smart-meters.html

Our analysis suggests that the most important factors to vary across the scenarios will be:

- **the pace of electrification of heat and transport;**
- **the increase in distributed generation; and**
- **the increase in intermittent and inflexible generation.**

Do you agree? Are there any other variables that we should look to vary across the scenarios and why?

We agree that these are by far the most significant factors in terms of the potential impact on electricity networks of low carbon transition (as it is currently envisaged). We believe that both pace and (ultimate) scale should be considered. However, it will be important to differentiate between technologies within each of these categories; for example, with regard to electric vehicles (EVs), the relative impacts on electricity networks of PHEV, BEV and EREV variants will be significantly different. Similarly, the impact of micro-CHP will be significantly different (actually more benign) to that of micro-PV.

A significant factor to consider for heat electrification is the peak heat effect. Heat pumps are unlikely to be designed to cater for extreme cold weather events and in the absence of any other fuel or energy source there is a high probability that supplementary heating will be in the form of electricity resistive heating; indeed, air sourced heat pump based systems often include resistive heating top-up elements. This has the potential to significantly increase the heating 'load'; indeed, the resistive heating element of the load can easily be dominant in extremely cold conditions.

Distributed generation should be regarded both as a smart grid value driver and – at least for controllable technologies – as a potential value provider.

It is also surprising that all of the scenarios assume that the UK will meet all of its Carbon targets, with the only variation in the speed of change. Initial UK Power Networks analysis indicates that unless there is a significant change to the incentive mechanisms and or legislative framework there is a risk that the UK will need to find other mechanisms (purchasing or trading in carbon allowances) to meet its commitments. Understanding the consequences of this would appear to be a valid consideration for assessing the smart grid framework.

Section 4: Smart grid and conventional investment strategies

Out of the options presented, which set of assumptions should we make on smart meter functionality?

The evaluation should be undertaken in full cognisance of recent DECC consultations and of the current dialogue surrounding smart meter and WAN functionality. The DECC September 2011 consultation on the detailed policy design of the regulatory and commercial framework for DCC[3] summarises, in Tables 6.2 and 6.3, the smart meter message flows that are believed to have a high and low/moderate (respectively) impact on Wide Area Network (WAN) cost/performance. Latencies (response times) are indicated for each described functionality.

[3] http://www.decc.gov.uk/en/content/cms/consultations/cons_smip/

However, these tables contain errors and omissions (and inconsistencies with the current Industry's Draft Technical Specifications (IDTS)[4] which will form the basis of the formal Smart Metering Equipment Technical Specification (SMETS)). A corrected and updated list of requirements from a 'DNO' perspective has been issued to DECC (through DNO representatives acting on behalf of the Energy Networks Association (ENA)) and further discussions are scheduled with a view to agreeing a final specification. A copy of the corrected and updated requirements is appended to our response. Both the ENA and UK Power Networks, in our responses to the above consultation, have recommended that DECC have regard to future likely volumes of low carbon technologies in finalising the performance characteristics of the WAN and in their assessments of tenders, and awarding of contracts, for the provision of WAN services. In particular, we have recommended that DECC take full account of the possible need for future WAN expansion (or upgrade) and are careful not to select technology solutions that might lead to future technical or economic stranding of WAN assets.

Assuming that the IDTS and these corrected and updated WAN performance requirements are incorporated within the SMETS, then we believe that the functionality within the smart meter, coupled with the performance characteristics of the WAN, will be sufficient to enable both Time of Use Tariffs (incorporating both 'energy' and 'use of system' time of day variable prices) and dynamic load switching within sufficiently 'fast' latencies to be deployed.

We would however emphasise the inherent dependency on suppliers for introducing time of use tariffs (and/or passing through any marginal cost-reflective use of system time variable prices). While suppliers would appear to have an increasing incentive to introduce more flexible (but uncomplicated) tariffs, there can be no guarantee of when such tariffs might be introduced, or to what extent they will be sufficiently granular to fully exploit flexible responsive demand. In this respect, it should be noted that the idealised ('smart') load shapes modelled for electric vehicle charging and heat pump operation in the report on 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks' (see Figure 3.3) assume perfect elasticity of electricity demand with regard to price signals and the introduction of real-time dynamic tariffs. The former of these assumptions is of course unrealistic in practice (even with the introduction of smart appliances), while the latter is an unlikely near-future development. It follows that these idealised load shapes represent a purely theoretical scenario, albeit a very useful reference for understanding the ultimate potential for responsive demand to contribute to distribution network cost efficiency.

Taking all of the above into consideration, we believe that the most likely medium term (to 2023) solution scenario for leveraging responsive demand is a hybrid of options 2 and 3 i.e. a combination of some enhanced smart meter communication combined with some smart grid investment.

It is important however to note that, whichever scenario is selected, considerable investment will be required in DNO systems to leverage the high volumes of data from smart meters that will be necessary to deploy either time of use tariffs or smart grid solutions. This investment should not be regarded as 'business as usual' under any of the smart metering scenarios.

[4] http://www.decc.gov.uk/en/content/cms/tackling/smart_meters/regulation/regulation.aspx

Do you agree with our proposed approach of including smart appliances in the business as usual?

We agree that smart appliances are fundamental to releasing the full potential of wet appliances and white goods to provide domestic responsive demand. However, sections 3.20–3.27 (and especially Figures 3−7) of the report 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks') illustrate that the scope is limited in terms of magnitude, duration and time-flexing.

While the incremental cost of 'smart' is relatively small, the benefit is nevertheless dependent on the availability of time of use tariffs and a home area network (HAN) solution that is able to communicate with smart appliances. While such a HAN solution is envisaged in DECC's August 2011 consultation on draft licence conditions and technical specifications for the rollout of gas and electricity smart metering equipment[5], the use of smart appliances for responsive demand will be dependent on suppliers or other parties providing the necessary controls and incentives, for example through time of use tariffs and price (and/or control) signals.

While it is reasonable to treat smart appliances as 'business as usual' in the context of not requiring intervention by DNOs, it is by no means clear as to how much of the potential from wet appliances and white goods will be realised in practice, and over what timescales.

A far more pressing requirement, ultimately, will be to ensure that controls and/or incentives are in place to discourage electric vehicle recharging at times of winter day peak demand (or, in the particular case where the distribution network has been designed to serve electrically heated homes using storage heaters and an 'E7' tariff, that electric vehicle charging does not coincide with the heating load).

Do our proposed smart grid strategies capture the main deployment options?

The potential smart grid deployment options are best described by the Work Stream 3 report and the 12 solution sets replicated in the consultation as Table 6. It follows that any simplification deemed necessary to undertake the evaluation exercise could potentially understate the scope – and hence both the benefits and costs of smart grid deployment.

In that regard, the four proposed 'representative' technologies (pages 81−82 of the consultation) are a small subset of the richer deployment options covered by the Work Stream 3 solution sets. In relation to these four technologies we would comment as follows:

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[5] http://www.decc.gov.uk/en/content/cms/consultations/cons_smip/

Electrical energy storage (EES)

The consultation notes the current high cost of storage, and while the advantage of EES in having no specific requirements in terms of geographic or geological features is acknowledged, the required physical footprint is nevertheless likely to be a significant deployment constraint as a retrofitted technology on an established network. Deployed in conjunction with and electrically adjacent to onshore wind farms (or at landing points for offshore distribution connected wind farms), EES has the potential to improve effective wind farm load (export) factors. Improving local network load factor would also confer benefits in terms of reduced variable losses which would, at least partially, compensate for conversion losses (cited in the consultation as typically 75% albeit we believe this to be pessimistic).

UK Power Networks has installed a proof of concept scale lithium ion based EES device adjacent to a wind farm in Norfolk as part of an IFI/LCNF project. However, as a universal deployment option to release capacity headroom, we would regard EES as having limited scope due to cost and footprint considerations, at least in the medium term. As a demand-side option (for example, in the form of EV batteries used in V2G mode), there might be greater scope in the future though the economics, bearing in mind impact on battery life and the need for an inverter, do not currently look attractive. SHEPD's Thames Valley LCNF2 project will deploy both demand side and street based EES modules.

To fully leverage the value of EES and ultimately make it an economic option, we believe it will be essential to exploit its potential to provide upstream ancillary services such as fast reserve or STOR (or even frequency regulation/response). This is a classic case of the smart grid value chain extending beyond the boundaries of the distribution network.

While not mentioned in the consultation, EES installations such as the lithium ion device installed in Norfolk, which uses a voltage source converter to simulate an AC voltage waveform, can provide important additional benefits such as power factor correction (continuously variable import or export of reactive power); harmonic filtering (which will 'clean up' harmonics imported from the network as well as those generated by the DC-AC voltage conversion process); and a limited duration source of standby power that could be used to support a self-islanded network in the event of a network power failure.

Dynamic Thermal Rating

The consultation correctly notes the potential benefits of dynamic rating in releasing thermal capacity headroom. In general, the additional amount of headroom created is small and this will need to be balanced against the cost of deployment. In practice, the economic application of dynamic rating in any given circumstance is critically dependent on whether the additional headroom created 'buys' sufficient capacity headroom (and time) to justify the NPV cost of deferred reinforcement.

(a) Overhead lines

While not mentioned in the consultation, as with EES, there is a natural synergy when dynamic ratings are applied to overhead lines serving wind farms. Put simply, when the wind is blowing, wind farms will generate electricity and overhead line ratings can be increased (this assumes that the line is not artificially shielded from the wind source due to geographic features). WPD's Low Carbon Hub LCNF2 project will examine the application of dynamic ratings to increase the rating of a 132kV network in support of an offshore wind farm connection.

(b) Underground cables
In the case of underground cables, the economics of deployment will generally be difficult to justify as a retrofit option due to the relatively low amount of headroom released and the cost of deploying sensors. Again, the economic test will depend on the (relatively low in this case) amount of headroom released being sufficient to justify the NPV cost of deferred reinforcement.

Dynamic ratings based on state estimation techniques, while potentially cheaper, will necessarily include a safety margin due to the inherent uncertainty in the accuracy of estimation of cable temperature, and the extremely high costs of replacement should the cable be damaged due to excessive core temperature, or should the cable suffer uneconomic life reduction.

As a means of increasing firm capacity (for example 132kV or 33kV cables serving grid or primary substations), since dynamic ratings will take effect only under outage conditions (assuming adequate safety margins), sacrificed life will be relatively low.

(c) Transformers
Due to their relatively high thermal inertia, transformers are normally rated according to cyclic ratings (i.e. a rating higher than a 'continuous' rating can be applied due to the fact that the core and windings will cool during lightly loaded parts of the day and heat up relatively slowly when load increases towards the daily peak). Moreover, for winter loaded transformers (the majority) it is not unusual to apply an overload rating (typically up to 130% of nameplate rating) without recourse to forced cooling. For summer loaded transformers (typically serving central business districts with significant air cooling load), then, depending on the cyclic loading pattern, even nameplate rating may not be achievable in some circumstances.

As with underground cables, the greatest scope for applying dynamic ratings is in respect of increasing firm capacity. Due to the thermal inertia of large primary or grid transformers, it is possible to apply bespoke dynamic ratings by studying the precise load profile of the transformers and their thermal characteristics[6] and hence understanding the rate of increase of winding temperature under an overload condition due to an unplanned outage on the adjacent transformer(s). Used in conjunction with automated load transfer where necessary, it is possible to apply short time ratings considerably in excess of normal or continuous emergency ratings that would ultimately result in a winding temperature trip operation without significant loss of life.

Since this technique need not involve additional monitoring, and since the transformers are in any case protected through winding temperature trip relays, the economic case is relatively easy to justify. This is a 'smart' technique that has been applied by UK Power Networks for many years.

Enhanced Automatic Voltage Control (EAVC)
We would broadly agree with the described scope for EAVC. Conventional AVC schemes serving rural networks traditionally apply line drop compensation which compensates for higher voltage drop along 11kV feeders at times of peak demand by boosting voltage at the primary substation busbar. However, if DG is connected close to the end of one or more of the 11kV feeders, this may undermine the principle of operation and result in voltages outside statutory limits.

UK Power Networks has deployed EAVC on 11kV networks where DG would otherwise be constrained due to its effect on voltage regulation, using a technology known as GenAVC. These were registered as 'Registered Power Zones' under the provisions then available during the DPCR4 period.

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[6] Based on CP1010 – loading guide for oil immersed transformers

It is important, however, to be mindful of downstream effects of applying EAVC at the higher voltage levels of the network hierarchy. The combined impact of EVs and micro-PV generation on LV networks will give rise to greater variations in steady state voltage to the extent that full use of the available voltage bandwidth (400/230V + 10% / -6%). AVC is not currently applied to MV/LV distribution transformers due to the prohibitive cost and hence LV voltage regulation is dependent on AVC at upstream primary substation transformers. It is therefore important to take full account of the downstream impact on LV voltage regulation of applying EAVC techniques at primary substations, in order to further exploit the available statutory voltage bandwidth of 11kV +/- 6%.

It may be that circumstances will arise in future where DNOs have little option but to install AVC at distribution substations and/or to install in-line voltage regulators (although replacing the transformer with a higher capacity unit or even overlaying sections of LV cable might often be a cheaper option). This is an example where DNO-led demand side response might prove a more cost-effective solution. SPD's 'Flexible Networks for a Low Carbon Future' LCNF2 project will deploy in-line voltage regulators and reactive compensation to combat the impact of heat pumps and renewable generation, while WPD's 'BRISTOL' LCNF 2 project will employ in-home batteries to store energy from PV panels.

Apart from EAVC, power factor correction through switched capacitor banks or D-Stacoms might be cost-effective options where poor power factor is giving rise to excessive voltage regulation on MV and HV circuits. Correcting power factor will also have benefits in terms of releasing thermal capacity headroom.

Technologies to Facilitate DNO-led Demand Side Response

These have been discussed above in the context of smart meter functionality and smart meter WAN capability.

The consultation is right to note that additional functionality and telecommunications capability might be provided through enhancements to existing (or new) SCADA systems (reference is made below to a new IP based telecommunications system which UK Power Networks will deploy as part of an LCNF project).

While the smart meter system is rightly seen as a key enabler of DNO-led demand side response (in terms both of a source of active load switching and the means by which time of use tariffs will be deployed), it is by no means the only supporting technology. For example, as part of its 'Low Carbon London' LCNF Tier 2 project, UK Power Networks is contracting with commercial aggregators who in turn contract with larger industrial and commercial consumers to provide responsive demand ancillary services. In order to enable the service, the aggregators will typically install monitoring and telecommunications systems to dispatch the demand response 'on call'.

The potential value of such a service lies in the hypothesis that it is possible to operate primary substations above (conventionally derived) firm capacity without loss of security of supply to consumers at large, through being able to call on a contracted level, speed and duration of demand reduction in the event of a 132kV or 33kV fault outage. Applied in conjunction with dynamic ratings (discussed above), the ‘Low Carbon London’ trials will test the reliability of demand response as an ancillary service alternative to conventional network reinforcement. If successful, UK Power Networks will work with other DNO representatives to draft a proposed update ETR 130 to enable responsive demand in future to be considered as an alternative to network reinforcement under ER P2/6 (or a further revision thereto).

Meanwhile ENW’s ‘Capacity to Customers’ project will examine the scope for interruptible connection agreements.

Have we provided an accurate overview of the main services that smart grid technologies can provide?

Although not described in the consultation, we note that Table 7 includes an additional (fifth) deployment option: that of dynamic network configuration. We believe this is a core smart grid technology solution which is already at a relatively advanced level of TLR (at least in its basic form), and which is capable of further development and wider application as a means of releasing capacity headroom by ensuring optimum relative loading of electrically adjacent circuits.

An obvious example would be that of two 11kV circuits sharing a common normal open point (NOP) where the relative loading on each circuit might vary over a 24 hour period (for example, one circuit might serve an industrial estate and the other a residential area). At present, NOPs are generally regarded as ‘fixed’ in the sense that they are changed only in the event of an arranged or fault outage (in the latter case increasingly through automated switching) whereupon a section of the network is isolated for maintenance, alteration or repair and supplies to other parts of the two circuits are continued (or restored).

While dynamic reconfiguration is increasingly now deployed to deal with fault outages (i.e. through prescribed automated switching sequences), especially on 11kV circuits, such reconfiguration might also be used in future to dynamically optimise headroom, for example in order to relieve a constraint (either a demand or generator export constraint), or simply to reduce network losses (which could also include de-energising primary substation transformers during light load conditions to reduce iron losses). UK Power Networks’ earlier AuRANMS (Autonomous Regional Active Network Management System) IFI project examined potential simulations of autonomous (as opposed to centrally dispatched) active network management as a potential forerunner to a Decentralised Energy Management System (DEMS). Meanwhile SHEPD has demonstrated real-time active management of dispatchable generation with its Orkney Islands based project.

UK Power Networks' 'Flexible Plug and Play' LCNF Tier 2 project will apply dynamic network reconfiguration, in conjunction with dynamic line ratings, to a wind generation dominated 33kV network; the objective being to minimise network constraints and maximise wind generation output without recourse to conventional network reinforcement, which would be both costly and potentially problematic in terms of obtaining route consents and planning permissions. As well as active management of generation output, the project will trial frequent-use switches (so that network configuration can be frequently changed to optimise headroom without fear of wear related degradation to the switches) and a phase-shifting transformer which will continuously optimise power flows across parallel 33kV circuits and relieve an existing CHP generator export constraint. IEC 61850 internet protocol technology will be used to provide the necessarily intense and low latency telecommunications capability.

At the other end of the distribution network voltage level hierarchy, as the consultation notes in the footnote on page 72 of the consultation, UK Power Networks has an IFI/LCNF project that will deploy active network reconfiguration to an LV network. Particularly on more meshed LV networks (typically those serving urban or traditional suburban areas), LV remote control and automation has considerable scope for more rapid post-fault supply restoration; for releasing thermal capacity headroom; and for reducing variable losses on heavily loaded LV networks.

As mentioned previously, the proposed framework by no means captures the full range of potential smart grid technologies that could be brought to bear in releasing capacity headroom on distribution networks. For example, fault current limiters, which might release fault level headroom capacity on an urban network in order to accommodate CHP/CCHP plant, are excluded from the technology set and while 'enhanced automatic voltage control' includes mention of switched capacitor banks there is no reference to modern power electronic applications such as D-Stacoms. Similarly, while electrical energy storage is included, there is no specific reference to voltage source converter technologies associated with the inversion of DC voltages, which are also able to provide reactive compensation and harmonic filtering.

Adaptive protection, which will be an important supporting technology necessary to release capacity headroom on higher voltage circuits (particularly with regard to active network management), is also omitted from the discussion, as are technologies associated with wider system monitoring and state estimation and the data and telecommunications systems necessary to enable these technologies. These are important enabling technologies which active network management and enhanced automatic voltage control will be dependent upon.

Do you agree with our proposed assumptions on the characteristics of these technologies?

To summarise our detailed comments against each of the technologies, we have a concern that the assumptions regarding application and scope are, on the one hand, understated in some respects and, on the other hand, insufficiently caveated in other respects. The framework evaluation should take full account of the applications being trialled as part of LCNF and other projects which are testing these technologies, but, equally, it should give consideration to technology readiness levels in terms of the possible technological or economic constraints on wide-scale deployment by 2023.

Equally important to the evaluation is to recognise the potentially wider system benefits of applications such as electrical energy storage and responsive demand, and the implications under the current regulatory framework for creating the market conditions necessary to release that full potential.

Overall, we believe it is essential to take full account of our various qualifying comments, both in terms of limitations and further opportunities surrounding the technologies considered and our comments relating to technologies implicitly or explicitly excluded. If these technologies (and hence the services they would perform) are to be excluded, it will be important for credibility to acknowledge the limitations of the evaluation as an overall smart grid evaluation framework.

Section 5: Value chain analysis

Are there any other groups in society that we should consider in the value chain analysis?

The framework considers the current main industry players: DNOs (but not IDNOs); TNOs; suppliers; generators and customers (if not explicitly then by reference to their role); and NETSO. The framework excludes commercial aggregators – presumably on the basis that these act as intermediaries between players rather than as a player in their own right, though we would question their exclusion on that basis alone. Potentially more significant is the exclusion of society more generally (which by default comprises 'customers' but whose value would logically be measured in terms of societal benefit rather than in terms of the purchased product or service).

Notwithstanding community and local government initiatives, society is ultimately represented by government and this is a particularly important consideration in the context of smart grids, whose primary driver (in the UK) is low carbon transition.

While low carbon transition is not a service that customers have specifically requested, nor expressed any willingness to pay for, it is nevertheless considered by most informed commentators to be essential and hence in the longer term interests of society.

While, as stated above, society comprises customers, this distinction is important in the evaluation of benefits.

Do you agree with our conclusions regarding the distribution of costs and benefits?

The framework broadly captures the potential benefits and some of the synergies and conflicts between those benefits. Cost distribution is less clear; for example (as described above) an electrical energy storage plant has the capability to provide distribution networks support (which might also directly benefit decentralised generators), an ancillary balancing service to NETSO, and potentially a trading/imbalance hedging risk benefit for suppliers and generators. A decision to invest in electrical energy storage plant might critically rest on the ability of the plant to deliver benefits across this wider value chain.

As a regulated cost incurred by a DNO this could therefore be problematic and require instead a joint venture where only a proportion of the costs are added to the DNO's RAV. An alternative model going forward might be that an aggregator (or VPP operator) could invest in the plant and sell ancillary services to DNOs, TNOS, NETSO, suppliers and generators. This model has the attraction that it would be for the aggregator to manage the conflicts between these services and extract the synergies.

One important aspect of DSR generally (and storage specifically) is that, depending on the means by which it is delivered, its duration might be relatively short and, moreover, once depleted, there will be a recovery period during which lost energy is recovered (generally from the grid) and during which time the ancillary service is unavailable.

For example, if a DNO calls on DSR to manage a short duration constraint (for example, to deal with a capacity shortfall in the event of a fault outage occurring at the time of peak demand), then the service may not be available later that day should, say, NETSO wish to call on it for STOR. This is particularly relevant to the case where air cooling or refrigeration is the basis of the DSR service, or indeed where embedded or network connected electrical energy storage is deployed. Where standby generation is dispatched, then the only limitation might be fuel reserves.

Ultimately the resolution of this conflict will depend on either establishing priorities or accepting risk. Typically NETSO will strike a number of STOR contracts with aggregators who in turn will 'aggregate' services from a wide portfolio of consumers. While a DNO's requirements have a high degree of locational specificity (i.e. consumers supplied by the temporarily constrained network), NETSO's requirements will generally be unconcerned as the source of the service. Hence, if a DNO were able to reserve a DSR service at times of potential stress, it may be possible for the aggregator still to provide the required service level from the remainder of his portfolio should NETSO need subsequently to call on that service.

For DSR to become a cost-effective service for all parties it will be essential to find a mechanism whereby the synergies can be exploited (i.e. the same service is not effectively 'double sold') and the potential conflicts managed.

One specific conflict that has been recognised (for example by Poyry[7]) is that DSR has potential market benefits as a means of maximising wind generation capacity in which mode the driver would be to follow wind generation output rather than maintain a flat load profile. Indeed, modelling suggests that with substantial wind generation capacity (e.g. 30MW+) the impact of wind following could create higher daily peak demands on distribution networks under certain daily wind pattern/generation/load scenarios.

Do you agree with our proposed approach to assessing the costs and benefits for the transmission network?

A clearer distinction should be drawn between TNO and TSO benefits. The former relates to transmission capacity headroom (and is a relevant consideration to all three on shore transmission network operators) whereas the benefits described in the framework document major on the TSO (residual balancing) benefits, which are of interest to National Grid as NETSO.

With respect to the former, while there should generally be upstream transmission benefits of flattening distribution network demand peaks, there will be occasions where this actually creates an increasing level of constraint in parts of the transmission network with high levels of generation due to loss of balancing demand. Indeed, this is the cause of a number of constraints to the connection of embedded generation (i.e. due to the local netting off of demand within the distribution network).

[7] Demand Side Response: Conflict between Supply and Network Driven Optimisation: http://www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy/strategy.aspx.

Section 6: Proposed model specification

How suitable is the proposed network modelling methodology which uses representative networks, with headroom used to model when network investments should be made on feeders?

We commented on the validity of the general assertion that the benefits of smart grids could be delivered through traditional reinforcement (albeit possibly at higher cost) as this ignores the avoided peak (generally fossil fuelled) generation benefits that smart grids can deliver through flattening demand peaks, which is an important element of the value chain.

In terms of the ‘headroom’ approach, while this explicitly ignores headroom effects created by fault level and power quality (and noting that higher fault levels, if manageable, are beneficial in terms of mitigating power quality issues), the simplifying assumption is that headroom constraints are driven either by thermal rating or statutory voltage bandwidth limits. It will therefore be important to acknowledge that, albeit not generally the primary driver, investment driven by fault level or power quality will not be covered by this analysis. Such investment might be necessary to permit connection of synchronous or induction generators; or to mitigate the impact of harmonics created by PV (or future V2G) inverters or heat pump soft-start systems; or, conversely, the impact of heat pump starting currents on voltage if soft-start systems are not used. All of these investment drivers are associated with the very low carbon technologies that smart grids seek to accommodate.

We note that the proposed conventional solutions to be considered are limited to replacing transformers, splitting feeders and new feeders (the latter two being variations on the same approach). Higher voltage injection is not considered (i.e. establishing a new substation rather than installing a new/split feeder), although this might be a necessary solution on already highly loaded feeders.

The selection of representative networks will be important to ensure a broadly representative model. It is unlikely that the less standard network architectures, such as the LV-interconnected 11kV networks extensively deployed in central London, will be adequately captured by a generalised urban 11kV or LV network.

It is also important to recognise that for P2/6 demand groups B and above (i.e. 1MW group demand), thermal (and potentially voltage) capacity headroom is driven by operating conditions following an outage; in other words, the consideration must be *firm* capacity headroom.

We note that the emphasis for modelling will be at the LV and 11kV (or 6.6kV) level on the basis that it is these networks which the majority of low carbon technologies will connect and (at LV in particular) where thermal and voltage constraints are most likely to first materialise. However, in terms of understanding the counterfactual, the impact of low carbon technologies on the overall demand profile and the extent to which smart grids are (or are not) able to mitigate peak demand growth will be material in terms of the extent to which investment (smart or conventional) will be required at higher voltage levels.

Are the voltage levels (from 132kV down to LV) being considered by the model appropriate, or should the model be limited to focus on any particular voltage levels?

The range of voltage levels included in Table 8 covers the majority of voltages and transformation points commonly employed on UK distribution networks (noting however that 132kV is considered a transmission voltage for Scottish systems). Excluded are: 66kV, 22kV, 20kV and 6.6kV; however 66kV, 22kV and 6.6kV can be broadly considered as (generally less modern) equivalents to 132kV, 33kV and 11kV and therefore generally associated with older assets, whereas 20kV is a modern enhanced capacity equivalent to 11kV.

For each of the voltage levels we are considering, are current methods sufficient to recognise available headroom and the cost of releasing additional headroom in these networks? If not, is the proposed approach considered to be too simple or overly complex?

With reference to capacity headroom considerations, it is important to understand that there are differing levels of inherent redundancy within alternative network architectures. For example, the classic two transformer-feeder primary or grid (leaving aside interconnection capacity) will have close to 100% redundancy in terms of intact capacity (i.e. either circuit will be sufficient to meet peak demand). For the London network, the more common configuration is a four transformer-feeder 60MVA intact capacity double-busbar primary substation which, in order to meet the requirements of P2/6 demand group C, may have as little as 33% redundancy in terms of intact capacity and yet still be able to exceed the first circuit outage requirement in that the whole of group demand remains connected.

A further architecture not covered by Figure 17 is 132kV to 11kV direct transformation, which is now a common feature of the more modern London network where the standard configuration is a three transformer-feeder double-busbar arrangement with 180MVA intact capacity (representing approximately 50% redundancy).

It should be noted that both the above configurations are operated with split busbars due to existing fault level constraints and that fault level at 11kV is the primary cause of constraint for generation connections at this voltage level.

While the proposed modelling approach is essentially to incrementally build load (and generation) at LV as well as generation at higher voltages, it will be important to understand the impact of this load and generation on higher voltage networks and the implications for conventional or smart reinforcement at these higher voltage levels. This is particularly important in understanding the counterfactual; for example, if little or no inroads into modifying daily load shape were made through DSR.

Is our approach to estimating the clustering of low-carbon technologies appropriate? Is any other evidence available in this area?

It is important to distinguish between clustering and regional bias. There are reasons to believe there might be a bias towards national take-up rates of new technologies – just as there is with economic activity, new housing starts and conventional load growth. Indeed, it will be important to recognise that conventional as well as low carbon technology driven load growth will impact on available headroom over the period of the study and that there might be significant regional variations in this respect.

Other considerations such as building fabric and housing density, and availability or not of mains gas, will be important factors in determining the viability of heat pumps as a form of domestic heating. Electric vehicle ownership is perhaps more likely in suburban areas where off-street parking facilities are more common and/or may be influenced by the availability of public charging infrastructure.

Clustering is a phenomenon that transcends all of the above and can be driven simply by local authority or housing association decisions for housing stock, or simply by neighbour influence.

Are the proposed generation model assumptions (a simple stack of generator types, no technical dispatch constraints, half-hourly demand profiles for summer and winter, and representative wind profiles) suitable?

This approach, while attractive in terms of simplicity, ignores a potentially more successful approach to the connection of wind generation in DG dominated networks. UK Power Networks' Flexible Plug and Play LCNF2 project should be studied and consideration given to the benefits of combining a controlled level of constraint with a range of smart grid solutions to create higher capacity headroom. WPD's Low Carbon Hub LCNF2 and SHEPD's Orkney Island projects are also worth studying in this respect.

Should a simple representation of interconnection be included in the model?

Planned or credible international interconnection should be considered from a system balancing perspective, albeit that correlation of wind generation output and demand across Europe might limit its effectiveness as a hedge for excesses or deficiencies of wind generation relative to GB demand.

Of greater concern is the proposal to ignore ramp rates, which might be a significant driver of conventional peaking plant/spinning reserve if DSR is not able, inter alia, to provide the required increase in STOR.

Does the model represent demand side response appropriately?

As commented previously, the assumption that DNOs will not be able to make use of DSR through smart metering without (implicitly 'investing in') an enhanced communications infrastructure might be pessimistic. Discussions are currently in train with DECC with a view to ensuring that DCC WAN procurement decisions are taken with due regard to the current and likely future communications bandwidth (to provide adequate data capacity, frequency and latency) to support DSR and active load management.

That such investment will be necessary, whether through DNO extensions to existing SCADA systems or through DCC data and WAN service Infrastructure investment, is not in doubt however; it should be considered as part of the overall evaluation exercise (since consumers will ultimately pay).

Indicative latency requirements are laid out in the SMIP Industry's Draft Technical Specifications[8] which will form the basis of the Smart Metering Equipment Technical Specification against which smart meters and WAN/HAN solutions will be procured.

[8] http://www.decc.gov.uk/assets/decc/11/tackling-climate-change/smart-meters/2393-smart-metering-industrys-draft-tech.pdf

With regard to frequency response, while frequency regulation is a possible future application for DSR (especially on islanded networks), frequency response to deal with sudden generation shortfalls is not a practical application for enablement by the WAN due to the extremely fast latency that would be required; instead, it is envisaged that smart appliances such as refrigerators could be fitted with an inexpensive frequency monitoring device which will disconnect the appliance in the event of frequency falling below a given pre-set threshold.

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