TGC response to OFGEM consultation on *Quicker and more efficient distribution connections*

Background

Britain reaps huge economic benefits from new infrastructure projects. They create immediate jobs, and deliver infrastructure which enable jobs and prosperity in the future. These projects include large scale redevelopment for housing and commercial property – particularly in London; low carbon distributed generation (DG), transport, and community energy projects. These all require connections to the grid but increasingly often they trigger piecemeal grid reinforcement which causes delays and costs. This can stop projects in their tracks.

There must be over 100,000 jobs in the DG industries, if all technologies are added together. These people work largely in British businesses, and there is great concern about what will happen to these capabilities if the grid issues are not resolved.

Many Distributed Generation developers are seeing their businesses come to a shuddering halt because of grid constraints. You only have to look at how the DNO's heat maps change over the last couple of years to see how bad the story is. Grid offers in excess of £16m for a 200kw scheme are increasingly common, and can never be funded by a generator.

Data in DECC's REPD and DNOs generation databases suggest that the grid does not need reinforcement to meet the 2020 targets. Historically DG developers have been encouraged by OFGEM to connect where there is grid capacity, in order to make best use of existing infrastructure and therefore minimise the costs to consumers.

The logic has historically been to use up the spare capacity as the amounts of DG required nationally for the 2020 renewables targets have been well within the national constraints of the network which was over engineered long ago. It is based on the premise that the level of DG in any one area should be no greater than the maximum demand.

However, this logic is now broken.

- Local generation and demand on each cannot be simply balanced, and there are many circumstances where one area needs to import energy from another:
    - Summer air con demand from London significantly exceeds the generation which is feasible within the capital. It is likely that distributed renewables across the UK will need to export to the Transmission network to send power to London.
    - Planning permission for renewables is not possible in the green belts, conservation areas, national parks and other protected areas. Homes and businesses in these areas need to import their energy from other areas.
    - Physical deployment not practical on many roofs with eg flats, loft conversions.
    - Week day demand in commercial & industrial areas may exceed generation capacity of the DG which is feasible there, and generation capacity which is feasible may exceed weekend demand;
    - Weekday generation capacity in domestic areas may exceeds weekday consumption, and evening and weekend demand may exceed generation.
- Further more the logic is broken for community projects who by their nature need a grid connection near the community in question.
- Whole regions can be constrained (eg the WPD's F Line)

The potential impact of future British energy scenarios on the grid is enormous, and the National Infrastructure Plan (2014)[1] suggests £80b of investment will be required in low carbon power generation and networks from 2020. This will be funded by consumers through electricity bills. – either through DNOs and Distribution Use of System (DUoS) charges or through generators and FIT/ROC/CFD levies.

No regulations need to change to unlock this investment in new grid capacity. DNOs need confidence and evidence of grid strategy so OFGEM cannot (on retrospective analysis) claim they are stranded assets and prevent the DNO from recharging them to customers.

There is a workable mechanism for DNOs to fund *simple* investment ahead of need but here is no workable mechanism for funding *strategic* investment ahead of *immediate* need. This is largely because predicting the future needs is currently challenging for DNOs, since these needs are influenced by LPA plans, developer activity, government incentives & economic conditions, and there is no overarching plan or strategy for the grid.

DNOs need the confidence they will not be retrospectively found to have acted inappropriately. This could come from OFGEM providing clearer guidelines on the "needs analysis" which DNOs are required to carry out before strategic investment.

So to resolve this grid lock (no pun intended) , we need the new government to answer a few questions:

- What is the Objective and budget for Electricity Market Reform (EMR) beyond 2020?
- What level of power sector decarbonisation are we trying to achieve by 2030?
- How much DG is required?
- What type of grid is required to enable decarbonisation in locations where generation cannot match demand?
- What is the most cost effective way to fund this?
- Do DNO business plans enable this, or is a reopener required?
- What guidelines could OFGEM offer to enable DNOs to conduct needs analysis for strategic investment?
- What does DECC want to become of the jobs in the DG industry while these decisions are made?

Options

We understand that OFGEM have been asked by number 10 to consult on options to remove these blockages. The following options have been tabled:

0) The connecting developer takes the risk of predicting future needs, funds the strategic reinforcement, and is reimbursed by subsequent connecting developers. (the is business as usual, or the "do nothing" option)
1) The DNOs take the risk of predicting future needs, fund the strategic reinforcement and recharge the costs to DUoS customers. (sometimes called Scenario 1 or the Regulated Asset Value (RAV) model)
2) The DNOs take the risk of predicting future needs, over and above initial connection contracted by a developer (which will be funded by electricity consumers through the

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/381884/2902895_NationalInfrastructurePlan2014_acc.pdf

FIT/ROC/CFD levy), funds the strategic reinforcement and recharges the costs to subsequent connecting developers (also funded through the FIT/ROC/CFD levy). (This is sometimes called Scenario 2 or the RAV buyback model)

3) The Local Planning Authority takes the risk of predicting future needs as part of its strategic plan, funds the reinforcement, and is reimbursed by subsequent connecting developers. (This is sometimes called Scenario 3, the Development Company or DevCo model)
4) Alternative options
    a. Reducing the need for reinforcement with Network Management.
    b. Better connection offer queue management
    c. Flexible terms for recovery of connection charges

Business as usual

The current second comer rules are unlikely to be widely used. Without an overarching grid strategy, it is hard to see how a developer's investment committee or bank would approve funding of grid investment on the basis that this might be recouped.

More importantly, the cost of capital for a developer is typically around 10%, in comparison to around 5% for a DNO so consumers would pay around twice for this approach. For example, a £10m grid investment depreciated over 45 year life of the asset, could create £45m of finance charges if funded by a commercial developer, or £22.5m if funded by a DNO.

Q1 & 2 – RAV Model

TGC recommends we proceed with the RAV model (ie scenario 1)

Britain cannot decarbonise the electricity system without investment in the grid. OFGEM's business planning process for the DNOs suggested that up to £60b of investment could be required. The decarbonisation is certain, but the technologies in the energy mix and their locations are not. Britain's future energy scenarios have been refreshed in 2014 for the Smart Grid Forum WS7 projects, and will need frequent refreshing in future.

Ultimately these costs will be funded by electricity consumers, either through increased DUoS charges (ie scenario 1) or through levies such as FITs/ ROCs or CFDs (scenario 2).

There needs to be some total system cost thinking, and joined up government: If the capital costs are funded by DNOs and recharged through DUoS, then the overall system costs are likely to be significantly lower than if they are funded by developers and recharged through FITs/ROCs or CFDs. As mentioned above, this is because the cost of capital for a DNO is typically 5%, but the costs of capital for a developer is typically over 10%. For example, a £10m grid investment depreciated over 45 year life of the asset, could create £45m of finance charges if funded by a commercial developer, or £22.5m if funded by a DNO.

The vital questions are how the DNOs take the risk on predicting the future to ensure that they don't have stranded assets, and how to provide revised locational price signals to encourage developers to connect in a location that triggers the lowest cost investment. The Smart Grid Forum and IET's system architect start to flesh out some of the answers to these challenges, guidance from OFGEM on the content required in a needs analysis for strategic investment would also be useful.

Q3-9 RAV buy back model.

If this approach were adopted, then developers could not be required to connect to the newly reinforced network. They would need to be subject to market forces, choosing sites which trigger the lowest reinforcement costs – ie the current approach of "minimum cost scheme" should continue.

The life of many DNO assets can be 45 yrs, and the life of the scheme which refunds the upfront investor should match this. The current second comer rules (which force subsequent developers to pay for reinforcement in the previous 5 years) include a perverse incentive for subsequent developers to delay their projects until after the 5 year recharge lapses. The administrative burden for DNOs to develop a computer system to manage this scheme is similar for 5 , 10 or full life, and adopting a full life scheme is a fairer way of sharing the costs.

DNOs then would carry a risk of only the uncertainty of timing of recharge to subsequent developers. To compensate the DNO for this risk, it is reasonable for them to charge an additional premium to subsequent developers.

Q10-16 Dev Co Model

The DevCo would ultimately have to be underwritten by a developer or LPA. It is likely that the LPA will need to take this responsibility otherwise a lead developer would have to underwrite all the other developers in the project.

DG is too dispersed for the Dev Co model to work

Q17-18 Network Management

Undoubtedly, there are projects which on a case by case basis will be workable with reduced security of supply, or a managed connection which the DNO disconnects in certain circumstances. These projects should be explored, but they are not a silver bullet which will solve the fundamental issues set out above.

The Smart Grid Forum Work Stream 7 DS2030 project[2] is modelling several tools to deliver Smarter Network Management:

Solutions based on installation of (a) new device(s):

- Energy storage,
- Automatic voltage regulator (AVR) on distributed generators (DGs),
- On-load tap-changer (OLTC) on 11(6.6)/0.4kV distribution transformers,
- On-network voltage regulators,
- Shunt and series connected compensation: SVC, distribution static compensator (D-STATCOM), solid state series compensator (SSSC), unified power flow controller (UPFC)
- Automation of switching devices,
- Fault current limiters (FCLs),
- Embedded direct current (DC) interconnections,
- Phase balancing via power electronics or balancer at 0.4kV.

Solutions based on application of (a) new operational procedures

- Demand side management (DSM) and demand side response (DSR),

---

[2] . http://www.smarternetworks.org/Project.aspx?ProjectID=1693#downloads

- Generation constraint management,
- Dynamic network reconfiguration,
- Permanent and temporary meshing of networks,
- Advanced voltage controls at individual and multiple voltage levels,
- Application of dynamic circuit and transformer ratings,
- Controlled EV charging.

The output of this important work needs to be quickly adopted by the DNOs into their business as usual

Q19-22 Queue Management

The current interactive offer process works well.

Speculative grid applications could be reduced by conducting chargeable feasibility studies with chargeable assessment and design fees at the start of the application process. If this system were adopted, the lodging of the feasibility study needs to ensure a place in the grid application queue. Some DNOs now offer this application approach and it could be rolled out.

Most DNOs are already managing offers against milestones which were clearly set out and defined in the offer, and with drawing offers if suitable progress cannot be shown. There needs to be a route of appeal to ensure DNOs are not withdrawing offers where developers have a valid reason for delay.

Q23-26 Flexible Cost Recovery

As discussed above, the cost of capital of a developer is typically around twice that of a DNO, so it would result in a reduced costs to consumers if the DNO funded the assets, and recharged them connecting customers over the life of the asset.

Q27-29 Summary

Provided there clarity on what we are trying to achieve, and a grid strategy to support this, then Scenario 1 (the RAV model) will – when the total system costs are taken into account – deliver the greatest benefit to connecting customers at the lowest cost to the consumer.