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WWU response to Ofgem's call for input: Future of local energy institutions and governance

Dear Victoria,

Thank you for the opportunity to respond to this call for evidence.

1. Are the three energy system functions we outline (energy system planning, market facilitation of flexible resources and real time operation of local energy networks) the ones we should be focusing on to address the energy system changes we outline?

Yes, we agree that these are appropriate functions; however, these should be considered on a whole network basis covering both gas and electricity and, in both cases, taking account of new demands on the networks such as for transport.

2. Do you agree with the criteria we have set out for assessing the effectiveness of institutional and governance arrangements?

We agree that the criteria of accountability, credibility, competence, co-ordination, simplicity are appropriate.

3. Do you agree with our assessment of how far the current institutional arrangements are, or are not, well suited to deliver the three key energy system functions?

The call for input takes insufficient account of the role of gas networks in the current and future system. Gas networks already perform real time operations to manage flexible resources and although electricity responses need to be faster than those required for gas, institutional arrangements for each sector affect the other.

The ongoing importance of gas across the energy system is illustrated by [ESO's 'Day in the Life 2035'](#), which relies on both baseload gas generation with CCS and 'dispatchable [power], such as hydrogen' to operate a fully decarbonised electricity system.

Examples of current gas network management of real time operations include:

- Managing gas quality from biomethane sites – through Network Entry Agreements
- Use of smart pressure control to maximise biomethane injection in areas where there are capacity constraints

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- Managing unpredictable changes in demand from flexible generation plants fuelled by gas resulting from changes in renewable generation – through Network Exit Agreements

Although gas networks have not produced different products and created new markets to manage flexibility, they have put in place revised commercial arrangements to facilitate flexibility on both gas and electricity networks. Considering the appropriateness of institutional arrangements requires a holistic view across the system.

4. Overall, what do you consider the biggest blocker to the realisation of effective energy system planning and operation at sub-national level?

The challenges relate to the complexity of interactions across the system at different levels. This requires clarity on the responsibilities of national, devolved and local energy institutions, and how networks should respond to legislation and policy from these bodies within their regulatory environment.

This complexity is increased by interaction between gas and electricity networks, which is likely to continue to grow in future. Currently the main flexibility mechanism between gas distribution and electricity distribution is the gas networks facilitating flexible generation by responding to on the day requests for more capacity this provides supply side flexibility to electricity networks. In the future it is likely that gas networks will provide flexibility on the demand side for electricity networks as excess renewable generation is used for electrolysis to produce hydrogen either to be stored to be used for heat or to be used to generate electricity.

We also note that as electrolysis to produce hydrogen becomes more common there will be increased interaction with water networks to consider the water required for electrolysis. Examples such as this mean that the energy system should be considered in the context of wider utility and resource planning.

5. Do you agree with the opportunities of change we outline and the potential benefits they may create?

We think that the focus is too narrow and that looking more widely at electricity and gas interactions at distribution level will reveal more potential benefits.

6. Are there additional opportunities for change and benefits that we have not set out?

As the call for evidence focusses on electricity it has ignored cross sector benefits. We envisage that peer to peer services between generators and operators of electrolysis could maximise the use of electricity generation that would otherwise be not used. The charges for this interruptible service may need to reflect the marginal costs of the generation and the marginal cost of the distribution network hence time of day tariffs may be required together with or instead of peer-to-peer trading.

The expected closer interaction of gas and electricity networks means that arrangements put in place relatively recently may need to be reviewed. An example of this is the interruption arrangements for gas put in place in 2011¹. These could be reviewed to make them more flexible for example by allowing new customers to connect on an interruptible basis or to allow peer to peer trading. An example would be a demand customer agreeing to only take gas when a biomethane customer is producing or alternatively agreeing to take gas at times of low demand to enable a biomethane producer to inject. The first example would allow a customer to connect without triggering reinforcement and the second would allow biomethane producer to inject when otherwise they would have to stop injecting. Biomethane production cannot be switched on and off so ideally they need to inject at a constant rate.

¹ Before 2011 Shippers on behalf of Daily Metered (now known as Class 1) customers could opt for an interruptible tariff under which they paid 50% of the capacity charge but were at risk of interruption. In reality, many customers knew whether they were on a network at risk of interruption and therefore some of them effectively could have a firm supply but at half the cost. In 2011 a commercial regime was introduced, under this arrangement the networks indicated where they were looking for interruption services and Shippers on behalf of customers made offers comprised of an option fee (payable if the offer was taken up by the network) and an exercise fee (payable each time they were interrupted).

7. We set out a number of risks associated with change. Do you agree with these risks and the potential costs they create? Are there additional risks of change and costs that have not been set out?

We do not have anything to add on risks but agree that significant change driven by a central programme requires regulatory and commercial resource that would otherwise be used for other projects such as Net Zero.

8. For each model, we have set out the key assumptions which need to be true for the model to offer the right solution. Which of these assumptions do you agree with?

The fundamental assumption seems to be that DSOs need to be separate from DNOs; this appears to be driven by concerns that DNOs may prefer building new assets rather than using commercial DSO solutions and therefore not separating the two functions is likely to lead to inefficient outcomes. We have two comments on this.

First, this risk assumes that networks will automatically prefer investment to operational expenditure. While this may be true in general, in practice investment needs to be funded before it is added to RAV and can be debt funded; therefore, licensees may have a limit to the appetite for investment due to cash flow considerations. Notwithstanding this we think that regulatory design could address this perceived problem. Different network expenditure (Totex) is allocated to different splits between money that is immediately recovered in revenue to that which is treated as 100% investment and recovered over the appropriate period. Careful consideration of the Totex treatment of DSO spend and investment spending where a DSO option may be available might make licensees indifferent to the two spends taking away any DNO bias towards investment.

Second, networks may prefer investment because it is seen as more reliable than commercial options. For example, each GDN has an obligation to be able to meet a peak demand expected on one day in every 20 years (the 1 in 20 obligation), currently the certain way to meet this is to book capacity from the National Transmission System and to design the system accordingly. An alternative approach would be to rely on biomethane producers injecting gas in the system on a peak day enabling GDNs to reduce NTS capacity bookings. The risk with the second approach is that we do not have sufficient confidence (borne out by experience in March 2019) that this injection could be relied upon. There is therefore a DSO solution, but it is not reliable enough for us to rely on it when a failure by the counterparty to the DSO option is a breach of licence. In this case relying on NTS operator that is licenced is considerably less risky than relying on an unlicensed biomethane producer. We understand that the equivalent obligation on DNOs is less prescriptive and if GDNs had an equivalent provision then we would probably be more open to using other options that are cheaper but not as certain.

9. Out of the framework models we have developed which, if any, offer the most advantages compared to the status quo? If you believe there is another, better model please propose it.

Our view is that a key issue that has not been addressed is the co-operation and collaboration between gas and electricity distribution networks and significant benefit could result from gas and electricity distribution networks working together and this needs to be encouraged. We would not support an explicit duty on DNOs and GDNs to co-operate and collaborate in these areas because it might result in networks having to put in place structures to demonstrate compliance rather than actually working together in areas where there is benefit for customers.

Currently any collaboration is informal. We do recognise that gas and electricity networks do not share common geographies so the scope for interaction for networks that have some, but small common geography will be limited. We also recognise that gas and electricity networks operate under separate legislation that does not contemplate interaction between them and this may limit the interaction that is legally possible. An example of this issue relates to justifying reinforcement of networks, under current legislation the gas network cannot consider benefit to electricity networks when considering reinforcement options. Ofgem should recognise the

need for closer co-operation and consider how this can be further encouraged for example around investment planning and innovation.

The above approach could be seen as an option under option 4 (interacting organisations); however, it may get lost under option 4 which could be very wide ranging and given that it is a relatively simple option it could instead be listed separately in Table 1 either before or after existing option 1.

10. What do you consider to be the biggest implementation challenges we should focus on mitigating?

All but the first model require primary legislation. We note that the legislation necessary to take forward BEIS's work on Code Governance Reform which is a response to a finding by the Competition and Markets Authority has not been included in the Energy Security Bill so we would caution against selecting a model that requires primary legislation in order for any benefits to be realised relatively quickly.

11. Taking into account the varying degrees of separation of DSO roles from DNOs under framework model 1, do you consider there are additional measures we should consider implementing, in particular in the short term (e.g. changes in accountability etc)?

As set out above, our view is that the focus is too much on electricity and the first two models (internal separation DSO activities within DNOs and Independent DSO) are both exclusively electricity focussed.

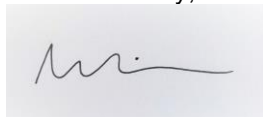
12. Are there other key changes taking place in the energy sector which we have not identified and should take account of?

The creation of the FSO has been referenced, and in relation to that we are concerned that the FSO needs to ensure that it has the necessary gas knowledge particularly regarding gas distribution. There is a risk that the FSO considerations are focussed on electricity transmission to the potential exclusion of local energy institutions and system wide benefits.

13. What do you consider to be the most important interactions which should drive our project timelines?

The ED2 price control process is well underway with business plans submitted so the impact of any change to arrangements will not be seen until ED3 business plans. There is also a relative short window before GD3 business plans are submitted. Options which do not require primary legislation would therefore be required if the ambition is to achieve change in time for networks to reflect any new arrangements in their business plans for these periods.

Yours sincerely,



Matt Hindle
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