3. A flexible grid for the future – Looking at what needs to be done to ensure the UK has effective infrastructure to deliver capacity for the future and support the development of renewable energy sources.

Closing date: 25th August 2023

British Hydropower Association response

The British Hydropower Association (BHA) is the leading trade membership association solely representing the interests of the UK hydropower industry and its associated stakeholders in the wider community.

Our Mission is to drive growth in the sector by engaging, influencing and promoting Hydropower, Tidal Range and Pumped Storage Hydro, as firm, renewable power, providing critical infrastructure for achieving Net Zero and Energy Security.

Table 1 – The BHA 'Asks' to Government

	Hydropower:	**Pumped Storage Hydro:**	**Tidal Range:**
Potential deployable capacity	1GW	15GW`	13GW
What is the BHA calling for?	Move to 'Enhanced' Levelised Cost of Energy inc whole systems benefits. Replace 1 GW of coal with 1GW Hydropower. CfD tweak for AR6: – Strike price £140/180MWh. – Reduce >5MW to >1MW. – Ring fence and aggregation potential for Capacity Market inclusion	A cap and floor, to enable delivery of the **15GW** called for in this CCC report	Regulated Asset Base, used for Nuclear, to enable delivery of **13GW**
What are the main barriers to support?	Hard to raise relevance (seen as, too small, can't scale, too expensive)	Geographically constrained, market can deliver batteries	Too expensive (i.e., Swansea Bay)

<table>
<tr><td>Why are these technologies important?</td><td>Resource adequacy, hydropower is cheaper than gas peakers (Reservoir hydro currently provides 900GWhs of storage and load follows)</td><td>Storage, reduced curtailment and balancing costs, grid stability/ flexibility (pumps and generates) currently 29GWhs, pipeline 135GWhs</td><td>Non-weather dependent, generation near increasing demand centres (circumvents transmission constraints), flood defence, socio economic value.</td></tr>
<tr><td>The counter points:</td><td colspan="3">Longevity: All these technologies are intergenerational assets that will deliver well beyond 2050 – true energy security.

Resource adequacy: What's the answer to 3 week Low wind period in 2035?

Energy sovereignty: Gas interruption, interconnector failure, French nuclear fleet refurbishment.

Reliability: Hydro/ PSH/ TR are all proven, reliable, long lasting & deliverable

Cost: LCOE: cheapest kWh will not deliver a stable grid. Lowest cost is not always best value. We need to move to 'Enhanced' LCOE and account for Non price factors.

Path to net zero:
• Fraught with delivery risk and time slippage
• To mitigate risk, we need diversity.
• We need all technologies being progressed rather than a favoured few.

Grid: How can we deploy localised energy solutions that will not be hampered by Transmission constraints.</td></tr>
</table>

Please see the case study attached which highlights the issues we have bringing useful 'flexible' storage online.

Renewable energy technologies all do something different on the grid. Hydropower should be compared to the cost of Gas Peaking plant, which at £250 MWh is much more expensive than Hydropower. 1GW of Hydropower could replace 1GW of gas peaking plant in the expensive capacity market or finally take off that 1GW of coal that is still loitering on the grid.

We need the flexibility and storage capacity of PSH but again, we need the stable price mechanism and we're calling on the Government to urgently bring forward a decision on the Cap and Floor that will enable the industry to deliver its 6GW pipeline. The cost of decision delay is adding cost to consumers.

Flexibility will be a huge part of our future grid (both on the generation side and the demand side) and that work is in its infancy and needs incentive mechanisms to speed up and scale urgently. Digitalisation of the grid to improve 'visibility' across the Distribution and transmission networks will be key if we are to ensure the grid assets are utilised to full effect. Just as the communications industry revolutionised and moved from analogue to digital, so must our grid

There are huge challenges to overcome if we are to decarbonise the grid by 2035 and there may be a tendency to be complacent with 208GWs queued to connect. But how much of that will get deployed and will it deliver a stable, operable grid that can deal with Dunkleflaute – 3 weeks of low wind? And with it answer the big resource adequacy question?

1. Does the current national and DNO grid deliver the capacity needed for the future and, if not, what are the solutions?

There are current constraints and there will be many future constraints as we move to a higher penetration of intermittent renewables and as the electrification of heat, transport and industry takes place. These constraints are across the entire grid, from Transmission, down to distribution, substation and rural 'weak' grid.

Vertically integrated planning

The ESOs Future Energy Scenarios (FES) takes a **whole systems approach**, and this approach needs to be cascaded down with more detail to the Distribution FES and a concerted effort to bring forward further granularity of detail through Local Area Energy Plans, Community based Local Area Energy Plans and then down to Sub-station level Local Area Energy Plans. This strategic, vertically integrated planning approach must be developed if best value for the consumer is to be realised through an efficient process of reinforcements. The proposal by Ofgem to introduce 'Regional Systems planners' could facilitate this approach and use a deep understanding of the distribution network to understand and create local, place based solutions.

Some of the Rural grid is 'weak' and will not have the capacity to meet electrification requirements. The cost of reinforcing the entire rural grid would be cost prohibitive, take too long, not be a priority and there isn't likely to be sufficient workforce to deliver. The solution will be to create local; place based solutions where new demand is met by new generation in Smart Local Energy Systems (SLES). Local balancing, local flexibility, digitalisation, Active Network Management will all need to be deployed to ensure the best and most cost efficient solutions are developed. This cannot happen organically, or piece meal, but will need holistic, whole systems planning which will require adequate skill and resource.

Focus needs to be on all forms of generation, not just large scale

There is a tendency to always focus on the large scale 'solutions', whereas multiple small solutions scaled up will have a cumulatively large impact. Generation at the Distribution network will play a key part in the net zero transition, but currently there are no incentives and small scale generation is overlooked by policy. Local, place based, whole systems solutions or SLES (Smart local energy solutions) must be given weighting in policy consideration, as these solutions will not be hamstrung by Transmission Grid constraints and will be able to be deployed despite of these issues.

Renewable energy generation has been focused on 'large scale or mass renewable energy generation' which has been dominated by Off-shore wind and solar – both huge success stories that have seen prices come down drastically and successful large scale roll out. However, 'resource adequacy' is a big unanswered question - the 3 weeks of low wind in winter. We have the ability to have a broad mix of generation technologies and as with investors, we should spread and mitigate risk through a wide portfolio of energy generation technologies. They all have different generation profiles and do something different on the grid. We need to move away from cheapest kWh to most useful kWh – i.e. when and where it is generated and where it is consumed. Lowest cost does not always mean best value.

Incentivising new generation

Currently the Contracts for Difference is the only incentive mechanism to bring forward renewable energy generation and this is focussed on large scale, mass generation deployment which will be mostly connected at the Transmission network. However, we need more generation across the distribution network to support the new demand of electrification. This generation will be key to supporting the decarbonisation of communities (especially in rural areas). Due to the volatile energy market, and low / short term Power Purchase Agreement prices, it is very difficult to get these generation projects to a bankable business case. They need either: a local energy market solution, or a standalone small scale renewables incentive tariff/ or the Contracts for Difference to be opened to smaller scale generation.

The 'cheapest' kWh and lowest cost 'Levelised cost of energy' must make way for more nuanced metrics that take into account the multi-dimensional issues and complexity of decarbonising the grid.

Small scale generation (<5MW) is a huge part of the decarbonisation journey. The Feed in tariff was closed and policy makers saw the large scale (>5MW) as being better value for money and therefore for consumers, however, this did not factor in the massive grid issues we face and how small scale generation at the distribution grid, alongside Smart systems can help alleviate some of these issues. A review of the benefits of small scale generation must be undertaken urgently.

2. Has the organisation of the National Grid proved a barrier to the installation of renewable energy sources, and if so, what could be done to remedy this?

Moving from a centralised to a decentralised Grid is a major shift for the TOs, DNOs and how they are regulated by Ofgem.

Decarbonising the grid has been underway for many years and this has been undertaken largely through the roll out of intermittent renewable energy generation. It is well known and documented that when intermittent renewable energy generation reaches a penetration of over 40% 'balancing' the grid gets more complex. The Grid operators have not been regulated in a way that mandated them to be prepared for the changes that can enable Net Zero delivery that we are now facing.

One of the biggest reasons has been the inability to **build ahead of need**, which is changing with new regulations from Ofgem.

Other reasons include a mix of:

- Monopolistic culture

- Protection of existing assets
- A culture averse to risk
- Institutional inertia

There are 3 major considerations that we need to urgently address when thinking about developing the Electricity gird for the future.

1. **Speeding up technical solutions**
    - Deploying technologies that will improve 'visibility' and enable the assets of the grid to be 'sweated' or the capacity to be maximised and efficient.
        - active network management
        - Dynamic Line Rating
        - Flexibility (demand & generation)
        - Digitalisation – this is really urgent and is happening too slowly

The above are not happening fast enough and are tied up with budget availability, time resource availability and the historic inability to 'build ahead of need'. There is also a general confusion over where to deploy first, to give best value, how this will fit with future reinforcements? There are so many variables and as the Nick Winser report suggests perfect won't happen and good enough will have to be the order of the day.

See questions below about innovation.

2. **Human resource** – this is rarely/ barely mentioned as a big barrier to the grid decarbonising and can be broken down as:
    - Tackling institutional inertia
        - How can Ofgem ensure there are the people with a remit to create the change and they are motivated to do so at pace?
        - How does Ofgem regulate to ensure the speed that is needed to start delivering this change (change makers and innovators in post asap etc)
    - We know regulated industries tend to work introspectively and be closed to external scrutiny; how can the TOs, DNOs, Developers/ Stakeholders and Ofgem adopt a better 'partnership' approach?
    - There is a shortage of people working on bringing forward innovations (not just competitions) .

3. **Communication**

Better planning and communication are going to be key to enabling efficient and effective implementation. There are 'Chinese walls' between TOs and DNOs, in part deployed by Ofgem as the regulator, but these need to be reconsidered, as an integrated partnership approach will be needed.

Ofgem needs to be an enabler, not just a regulator. The Regional System Planners and Future System Operator need to be dispatched and effective as soon as possible.

3. Should there be more innovation and devolution in the development of the Grid?

Innovation must be scaled at a much faster rate. The Strategic Innovation Fund and pathfinder funding is a great way to bring forward innovation which can maximise the potential for the UK grid to decarbonise, however, there is not enough funding and the competitive rounds of funding, where only 3 projects get feasibility funding and then 1 progress to demonstrator, is not enough. The TOs and DNOs need to have innovation targets, currently, innovation seems to be arbitrarily taken up and DNOs choose which projects will have benefits for them, without looking at what will benefit consumers and developers. As suggested above, deploying technologies that will improve 'visibility' and enable the assets of the grid to be 'sweated' or the capacity to be maximised and efficient must be accelerated. There should be mandatory annual targets for TOs and DNOs to roll out:

- active network management
- Dynamic Line Rating
- Flexibility
- Digitalisation

Again, the Regional System Planners and the Future Systems Operator should be front and central to these processes, ensuring coordination, learning and knowledge sharing.

To reduce the costs of reinforcement Smart Local Energy Systems (SLES) should be considered and fed into Local Area Energy Plans – as suggested in Q1. Again, this needs to be coordinated by people with the knowledge and ability to share learning.

4. What changes should be made to the planning system to enable it to increase the use of renewable energy?

As suggested above, if the NZ transition isn't going to grind to halt as the Grid becomes an increasing barrier, Smart Local Energy Systems that are flexible and can be deployed despite grid constraints will be key.

These whole systems, place based solutions that will include local generation must be fast tracked through planning as 'Strategic community assets. These could be picked up and highlighted in community based Local Area Energy Plans.

Community owned wind and hydropower will be key local generation assets where appropriate and with community consent should be fast tracked through planning.

This all ties into community scale decarbonisation of heat – please see response to 'heating our homes' where this dove tails.

5. Is our planning system able to deliver more rapid development of new local infrastructure?

No. There is currently a huge deficit of planners within Local Authorities. In one Local Authority in the Northwest there were no planners at all after a series of people left. This left a huge backlog and delay. There is also still a backlog from Covid and times for decisions are taking longer and longer.

With the ability to convene people online, there should be more around Community Local Area Energy Plans and the ability to create public commentary and involvement that can feed into the planning process.

Due to grid barriers/ delays and the planning process, projects that would once take 6 months to get over these hurdles are now taking over 2 years.

Local Authorities need to have a 'planners' premium' to clear backlogs and fast track decarbonisation planning projects.

6. Would regional, or nodal, pricing of energy facilitate a more flexible development of Grid infrastructure?

The Review if the Electricity Market Arrangements (REMA) is looking to create market solutions for the issues we have with the grid. However, the complexity of the challenge cannot be wholly delivered by markets, the grid is physics and works on a 'just in time' model where variable generation profiles need to meet a variable demand profile and this all needs to be done without the luxury of the terra watt hours of storage that fossil fuels have afforded us. Considering the problem through total installed capacity or total generation, misses this fundamental and crucial point.

Although regional, zonal and nodal pricing will have some impact, it does not address the underlying issues. We need more renewable energy, most of this will not be sited near centres of demand, we need to use our grid assets much better and more efficiently (sweat the assets) (digitalisation/ flexibility/ active network management) will all be much more effective than changing the parameters of the market.

Energy generation needs to be sited where it will have the most efficiency and this will not necessarily correlate to demand (i.e. wind in Scotland, not the SE) Those renewable energy sources are not going to change, so this issue will be as relevant now as in 50 years.

There could be some demand siting closer to generation (For example just as Aluminium smelters were placed next to Hydropower resource in the 1920s (and still operating today) Data centres and Hydrogen generation facilities can be placed near centres of high generation and low demand) However, the Grid must be adapted to accommodate decentralised energy generation where some renewable energy generation will be sited far from energy demand centres.

The opportunity to develop Tidal Range has been overlooked and this needs to be urgently reconsidered. Tidal Range offers large scale generation near centres of increasing demand (Cardiff, Liverpool etc where demand will increase 2.5 times due to electrification of Heat, transport and Industry) Tidal range has the perception of being more costly than other technologies, such as off-shore wind, but when considered against the backdrop of the massively constrained grid and the associated costs of siting generation away from centres of demand, Tidal Range should be considered good value for money. Resource adequacy is also a bug unanswered question and non-weather dependent technologies such as Tidal Range, that offer timetable generation will be a key technology within the decarbonised energy mix.

The word 'capacity' needs to be reviewed. Capacity brought forward by different technologies must start to be considered differently rather than homogenously. The capacity of an offshore wind, hydro (with storage) and solar are very different and have very different generation profiles. Lumping everything together as 'capacity' misses the nuances required for a decarbonised grid.

Queues must be reviewed with the mindset of what each project 'capacity' will bring to the grid in terms of generation profile matching a future decarbonised demand profile, whether there is storage co-located or how flexible the generation can be (or how costly to curtail?)

A much more flexible approach is needed with a view to what each project will bring over the next 20 or 30 years to the grid. Curtailment of wind is a massive and costly issue and one that was entirely predictable. We have weather data, and we can predict what generation will look like into the future, better forecasting of what the impact of projects will be on the grid over the long term must be taken into account when looking at project queues.

A **matrix of benefits** for the grid and for consumer costs should be applied to project queues, this could include deliverability of a project, but also criteria that look at the benefits it will bring to operability and stability for a long term decarbonised grid. Projects are currently market led (i.e. brought forward due to perceived commercial gain due to the incentive mechanisms available) Therefore competition for connections has been driven by a market led (skewed by incentive mechanisms) process, not a utility led process.

The ESO has the ability to add in utility based priorities that will enable the objective of a decarbonised, stable and operable grid. A transparent matrix that will enable priority projects to move up a queue would not distort this market but would reduce the overall cost that consumers face for congestion, curtailment and reinforcing the grid that is the consequence of the market distortion currently in place from FITs and CfD incentive mechanisms. This would not be a 'locational price signal' but would encourage developers to look more closely at what is queued and what is likely needed on the grid at particular points and therefore more likely to leapfrog other projects. Projects that co-locate storage would be given higher points in a matrix and therefore look to move up a queue – this would encourage developers to look at how they could gain additional points in the matrices by adding features that will be beneficial to creating a decarbonised, stable and operable grid. This would encourage developer led innovation, something that at present doesn't happen as there is no perceived need by the developer to do so.

With the large queues for grid connection, ESO has a huge opportunity to use the queue as a way to encourage developers to design their project to become more 'grid friendly' and therefore cost the consumer less downstream in terms of curtailment/ congestion/ reinforcements. Co-location of storage, active network management, consideration of Smart grid measures and even smart local energy systems could all be additional 'add-ons' that the developer could think through to ensure their project met higher criteria in the grid queue prioritisation.

This would push developers into becoming a bigger part of the grid solution rather than a more passive connection that is not being innovative or enabling the future smart grid.

The current 'passive' queue system is not leveraging the finance/ innovation or motivation of developers to be part of the solution. ESO should work harder and better with these developers to bring forward solutions that many developers will be keen to adopt, if they know it will get their project higher up the queue.

An element of competition already exists within the queue, but it has been the competition of first come first served. This needs to be reconsidered and competition should be brought into the queue, but the competition should be which project will **'best serve'** the overall ambition of a decarbonised, stable and operable grid.

First ready, first served is compounding the issues that are already there. A hydro project will take longer than a solar project to be developed and built but will offer a very different generation profile and will also be there for 80 years. First ready approach fails to look at the next 20 years and what will be most useful on the grid? A 'best serve' approach should replace 'first ready'.

7. What can be usefully learned from power transmission systems in other countries?

It is useful to see how other countries grid's function, however, the UK is a complex grid within a country with a unique geography, population densities, industrial profile, weather patterns and renewable energy resources, we should be looking at the physics of the UK grid and then looking at what needs to be developed to ensure it is stable, secure, resilient and operable.

Appendix A: Allt Na Moine Hydro storage case study

1. Summary

- Allt na Moine is a recently completed 2 Megawatt storage hydro scheme, located to the north of Applecross in Wester Ross.
- The final Feed in Tariff scheme to be completed, Allt na Moine has the capacity to generate more than 10,000,000 kilowatt hours of renewable electricity each year – equivalent to the annual consumption of more than 2,500 homes.
- The reservoir allows 150MWhs of storage, meaning the scheme can be responsive to the needs of the grid and local wind farms.
- Due to protracted delays in upgrading the Transmission network between Fort Augustus and Broadford, Allt na Moine is only permitted to export 50 kilowatts of electricity until such time as these works are completed. As things stand, this restriction will apply until the end of 2026 at least.
- The UK urgently needs to get additional renewable electricity on to the grid to address short-term energy security issues and to get back on track to achieve the declared ambition of Net Zero by 2035.
- Storage hydro represents the ideal technology to complement other renewables, most notably onshore and offshore wind.
- The opportunity exists for all parties to achieve a win by enabling Allt na Moine hydro to make use of the considerable 'dynamic headroom' that is understood to exist, but this will require a shift in approach from the rigid policies and procedures of the past to a much more flexible approach that utilises the latest grid management technology.

2. Background

Allt na Moine is a 2 megawatt storage hydro scheme, 6 miles north of Applecross. The scheme completed construction in summer 2022 and has now been energised and G99 certified in conjunction with SSEN but is unable to export more than 50 kW due to a grid constraint that was originally due to be removed in 2021 but is now scheduled for late 2026, at the earliest.

Figure 1 – Reservoir with 150MWhs storage

Developments such as Allt na Moine have for many years been actively encouraged by UK and Scottish Governments in the critical drive to reduce carbon emissions. The introduction of Feed in Tariffs by the UK Government in 2010 was specifically intended to stimulate the construction and commissioning of renewable electricity generating schemes such as this. In order to qualify for Feed in Tariffs, applicants required to have full planning consent, a CAR licence from SEPA, and a grid connection offer from the relevant DNO. All three of these items placed demanding obligations on the developer, however in the case of the grid connection offer, the arrangement was very one-sided, with no obligation on the DNO or Transmission counterparts to adhere to quoted timescales or costs, as so clearly demonstrated in the case of Allt na Moine.

The table below details the extent to which the cost of connection and the projected connection dates have moved in the past 5 years. It should be noted that the costs shown in the table do not include any amounts for attributable transmission works (c. £265k) or wider cancellation charges.

Table 2 – Grid connection cost escalation and time slippage

Offer date	Connection costs (Distribution) exc. VAT	Connection date (Distribution)	Connection date transmission
April 2017	£829,806	31 August 2020	31 October 2022
September 2019	£1,455,685	31 December 2020	31 October 2024
March 2022	£2,155,187	15 December 2022	31 December 2025
September 2022 Additional substation costs of c. £336,000	£2,491,177		31 October 2026

Since the original grid connection offer was made to Innogy (now RWE) in April 2017, the overall costs, excluding transmission related payments, have trebled from £830k to £2,491k. And there is no guarantee that the costs will not increase further.

At a time of national and international energy crisis, when plans are being made for power cuts and old coal plants are being readied for use, there has to be a way of bringing the full generating potential of this renewable generation asset on to the national grid. The situation during week commencing 12 December 2022 confirmed the preposterous situation facing Allt na Moine. A prolonged spell of very cold, still weather resulted in power shortages, as neither wind nor solar was able to deliver any meaningful volumes of electricity. During this period, Allt na Moine hydro could have been running at full capacity, taking advantage of the 150 MWh storage capability of the scheme. However, due to the Transmission constraint, lack of active network management or visibility of the scheme for the Transmission operator, Allt na Moine was still constrained to deliver a meagre 50kWs to the Grid.

 

Figure 2 – intake to penstock from Reservoir

At such times when other sources of renewable generation are subdued, there will be capacity available on the grid to accommodate not just Allt na Moine, but other generators waiting for the Broadford Transmission upgrade.

A Derogation has been in place, covering the Broadford GSP, since 2010. When it was introduced, it was a positive initiative that enabled the early access to the grid for many renewable generators who would otherwise have had to wait for upgrades to the Transmission network. But over time, the same Derogation has become an obstacle to new development. With this Derogation in place, there would appear to have been less onus on completion of the otherwise required upgrades to the Transmission network.

It is evident that the Derogation achieved its original aim of getting more renewable generation on to the grid, but for the reasons stated above it has failed to optimise utilisation of available grid capacity. Because of the related obligation to make constraint payments to generators in circumstances when combined output exceeded physical capacity, it was wholly understandable that the Derogation only allowed for a fixed % of 'overselling', but the circumstances in 2023 are quite different, therefore the challenge is to find a way of getting more generation on to the grid, 365 days of the year, without increasing the financial exposure to constraint payments.

The solution proposed is for future beneficiaries of the Derogation <u>not</u> to be eligible for constraint payments. They will be the first generators to be temporarily excluded from grid access and will receive <u>no</u> compensation in return. For generators with storage assets, such as Allt na Moine Hydro, this will impact the timing of output, but with little or no impact on overall generation.

Each scheme that operates under the G99 regime can be directly managed from the SSEN Control Centre in Perth, as was demonstrated during the G99 witness testing at Allt na Moine on 17 January 2023.

3. Obstacles to connection

The primary obstacle to Allt na Moine being fully connected to the grid before the Broadford Transmission upgrade works are completed is the Derogation covering the Broadford GSP has been applied by SSEN Transmission. This states that no new connections of more than 50 kW can be added until further Transmission upgrades are completed.

There are two connected schemes in the vicinity currently restricted to 50kW which contracted prior to Allt Na Moine. They will increase their export to 90kW and 100kW (+90kW total) respectively upon completion of the Transmission reinforcements. Allt Na Moine is next in queue followed by an already connected scheme restricted to 50KW who will increase to 100kW, and a contracted scheme of 137kW.

In summary, the total extent of 'the queue' is less than 2.5 MW.

Figure 3 – Turbine and powerhouse, a low visibility, low impact scheme that will generate for 100+ years (true energy security)

4. Progression towards Active Network Management

The following high level timeline shows the developer's request for consideration of Active Network Management as a proposed solution to the transmission constraint leading to curtailment of Allt Na Moine scheme with SSE:

1. First suggested by SSE in November 2022 – they then immediately dismissed it as too expensive, on the basis that the developers would not be interested – despite having that conversation.
2. Follow up call with SSE Flexible connections team in January 2023. Talk of Cost of £200k and 6-12 months to implement. They were going to go and confirm these timeframes/costs.
3. Regular calls and emails with SSE distribution team following up on the above action in Feb and march – no response
4. Raised again at our meeting with SSEN team in April 2023 in Perth. They took the same action to investigate.
5. Raised again in our call with SSE in June – same action.
6. Raised again in our call with SSE in July – no further response from SSE, and no offer yet received from Distribution.

5. Conclusion

As can be seen from the case study, trying to connect schemes to the grid is an expensive and moving feat, with no guarantees, moving goal posts and no obligation from the Grid operator to the developer, to deliver on time, with the specified capacity. This scheme has the very real threat of going bankrupt and due to very high business rates, the cheapest option would be to bulldozer the infrastructure, leaving the gird minus a 2MW, storage scheme with flexibility, storage, inertia for what should be 100+ years.

As stated above, much of the issue lies with the inability of the grid operator to build ahead of need, however, there is also an inability to be innovative and work with developers to explore all options, often due to resourcing and finding constraints.

This scheme can be turned on and off within the distribution control room at Perth, however, as this is manual and not automatic, there is a risk that if there is a fault, the person watching the scheme may not be able to turn it off in time, this could be resolved if the process was automated.

DESNZ Committee

4. Keeping the power on: our future energy technology mix – Exploring how the energy mix of the UK needs to change to deliver enough capacity while delivering against Net Zero targets.

1. Is the energy sector open enough to new generation technology?

As an Island nation, the UK has the ability to harness huge indigenous energy resources which could allow the UK to become a net exporter of energy.

The question does not clarify whether the Committee means 'new' as in 'new technologies' or new as in increased new generation plant. If the committee is implying the first, then the answer is yes. The UK government should be open to 'new' technologies, but not get distracted by 'silver bullet' solutions which avert focus from the delivery of existing technologies in the here and now. CCUS and Hydrogen are both likely to have a role in our Net Zero future, but there is a significant gap between the likely delivery/ scale and the over hyped expectations. Optimism bias, vested interests and the leaning to simplify complex problems with 'new' solutions are a real and significant barrier to delivery of existing technologies that are proven and can deliver to expected timescales.

The capacity market is currently the only mechanism to bring forward generation and flexibility to meet the resource adequacy question. Although this is under review, the continuation of a siloed approach across CfD and the Capacity Market does not allow for whole systems thinking or a joined up approach. 1 GW of hydropower could be brought forward if the CfD was 'tweaked' to reduce the lower parameter from 5MWs to 1MWs. 1 GW of Hydropower would reduce the requirement for 1GW of capacity within the capacity market as the generation profile of Hydropower means that it will be generating across times of grid stress (winter, peak teatime demand) The current mechanisms fail to recognise or consider these cross benefits.

Pumped Storage Hydropower will deliver much needed security, storage and flexibility on to the grid, yet it is being compared with other technologies, such as the interconnectors which is not a helpful or suitable comparison to make.

Tidal Range currently receives no support, and it is suggested that Government forms a partnership with Industry as they did to support the offshore wind industry nearly 20 years ago. Tidal Range offers a significant resource of up to 20GW of non-weather dependent, time tabled energy generation near to increasing centres of demand (Cities such as Cardiff and Liverpool that will see their demand increase 2.5 times as we electrify heat, transport and industry) this circumvents the significant barrier that the grid is posing in the plans to decarbonise the grid by 2035.

CM and CfD are Market based mechanisms which will only go so far towards delivery of a Net Zero Grid. It is hoped that the FSO can see the gaps and flaws and help make suggestions to realign policy to address the gaps.

The Grid is physics and decarbonising the grid cannot be done using market solutions set by policy makers without understanding the nature of grid. Real time Generation profiles, not Total Installed Capacity needs to be considered when we're thinking about what should be brought forward as a priority through the CfD. The non-price factors should be brought forward as key enablers for decarbonising the grid. This should include crucial review of what the CfD is not bringing forward across the grid, i.e. smaller scale generation that will be needed to decarbonise across the distribution network. Hydropower, Anaerobic Digestion, Smaller scale onshore wind will all enable local place based, net zero transition (despite grid constraints across the Transmission networks)

2. Does the Government sufficiently support development of innovative energy infrastructure?

The Electricity Grid is our biggest energy infrastructure and is not ready for a high penetration of intermittent decarbonised generation such as wind and solar. The £54 Bn being invested as part of the Holistic Network Design is for Transmission level reinforcements but will do nothing to alleviate the issues that cascade down to the Distribution and rural areas of 'weak' grid that will be unable to support the electrification of heat, transport and Industry.

Huge amounts of innovation must take place if the Electricity Gris is going to be able to deliver the Net Zero ambitions of Government and this should be the main priority over creation of new infrastructure for Hydrogen and CCUS.

The Strategic Innovation Fund and pathfinder funding is a great way to bring forward innovation which can maximise the potential for the UK grid to decarbonise, however, there is not enough funding and the competitive rounds of funding, where only 3 projects get feasibility funding and then 1 progresses to demonstrator, this is not enough.

There is much emphasis on funding for Hydrogen transmission and storage and CCUS. This is large scale infrastructure, and the use case has not yet been proved. The BHA would recommend that this continues to be researched as an addition to a Net Zero transition that is not reliant on either Hydrogen nor CCUs (with abated gas).

There is a tendency to always focus on the large scale 'solutions', whereas multiple small solutions scaled up will have a cumulatively large impact. Generation at the Distribution network will play a key part in the net zero transition, but currently has no incentives and is overlooked by policy. Local, place based, whole systems solutions or SLES (Smart local energy solutions) must be given weighting in policy consideration, as these solutions will not be hamstrung by Transmission Grid constraints and will be able to be deployed despite of these issues.

3. Is the Governments plan for energy security sufficiently long term?

No. The Government wants to decarbonise the grid by 2035 and reach Net Zero by 2050. Many Hydropower and Pumped Storage Hydropower plants are designed for 80 year life cycles, and with refurbishment, can continue to generate well after this design date. This is true energy security.

Energy security should encompass maximising the UK's indigenous energy generation with a 100 year plan. Just as our electricity grid, water/ wastewater and rail infrastructures are utilised for this duration of time, so too will energy infrastructure we implement today. Electricity is a societal necessity as important as water/ wastewater and with so many factors of modern life interdependent on electricity, Energy security is a critical infrastructure and cannot be left to chance.

The ESO has the Future Energy Scenario pathways, these are to 2050 and should be extended to 2075 and then projected to 2100.

4. What current technologies could usefully be deployed at scale to deliver better energy security in the UK?

Table 3 – The BHA 'Asks' to Government

	Hydropower:	**Pumped Storage Hydro:**	**Tidal Range:**
Potential deployable capacity	1GW	15GW`	20GW
What is the BHA calling for?	Move to 'Enhanced' Levelised Cost of Energy inc whole systems benefits. Replace 1 GW of coal with 1GW Hydropower. CfD tweak for AR6: – Strike price £140/180MWh. – Reduce >5MW to >1MW. – Ring fence and aggregation potential for Capacity Market inclusion	A cap and floor, to enable delivery of the **15GW** called for in this CCC report	Regulated Asset Base, used for Nuclear, to enable delivery of 20**GW**
What are the main barriers to support?	Hard to raise relevance (seen as, too small, can't scale, too expensive)	Geographically constrained, market can deliver batteries	Too expensive (i.e., Swansea Bay)
Why are these technologies important?	Resource adequacy, hydropower is cheaper than gas peakers (Reservoir hydro currently provides 900GWhs of storage and load follows)	Storage, reduced curtailment and balancing costs, grid stability/ flexibility (pumps and generates) currently 29GWhs, pipeline 135GWhs	Non-weather dependent, generation near increasing demand centres (circumvents transmission constraints), flood defence, socio economic value.
The counter points:	**Longevity:** All these technologies are intergenerational assets that will deliver well beyond 2050 – true energy security. **Resource adequacy:** What's the answer to 3 week Low wind period in 2035? These technologies will help alleviate this risk. **Energy sovereignty:** Gas interruption, interconnector failure, French nuclear fleet refurbishment. **Reliability:** Hydro/ PSH/ TR are all proven, reliable, long lasting & deliverable		

	Cost: LCOE: cheapest kWh will not deliver a stable grid. Lowest cost is not always best value. We need to move to 'Enhanced' LCOE and account for Non price factors. **Path to net zero:** • Fraught with delivery risk and time slippage • To mitigate risk, we need diversity. • We need all technologies being progressed rather than a favoured few. **Grid:** How can we deploy localised energy solutions that will not be hampered by Transmission constraints.

As stated in the table above there are proven technologies that need support to deploy. Government has always been reticent to support 'proven' technologies as they feel that they should not be 'subsidised' if they are no longer innovating and are market ready. However, the energy market suffers from market distortion and market failure. Energy price volatility is a product of global gas markets and will continue to be unstable. Creating a stable price mechanism is not giving subsidy but is giving certainty to investors and allowance of bankable business models that will allow deployment. The Government investing in these longer term price signals is an effective way to help deploy a stable, operable, decarbonised grid, for technologies that will be generating many years after the 15 year incentive mechanism and will offer value to consumers.

5. Are there technologies that have not been able to develop their potential and should be abandoned?

It is worth pursing all avenues, however, too much focus on 'silver bullets' is dangerous. There needs to be consideration of deploying all technologies that are known to have low deliverability risk. As with investor portfolios, have a spread of technologies will help mitigate risk.

6. What energy generation mix will get us to net zero the quickest in the most affordable way?

The Future Energy Scenarios should be followed and implemented as the DESNZ delivery plan with 6 monthly progress updates and scrutiny to ensure an understanding of technologies that are not getting deployed at their expected delivery rates are picked up and mitigation is possible. For example the CfD Auction Round 4 offshore wind may not be deployed due to escalating costs due to inflation. Learning should be taken from this and in future there should be a mitigation plan in place to cover this unexpected lack of generation in the pipeline.

Moving away from the Levelisied Cost Of Energy as the most important metric is key. This metric is not nuanced enough to develop a stable, secure, operable decarbonised grid and reflect true value for consumers. A whole system approach with a view holistically across net zero must replace this base line of cheapest kWh.

7. Are the energy solutions universal across the UK or are there regional and local approaches on fuel and energy?

Vertically integrated planning

The ESOs Future Energy Scenarios (FES) takes a **whole systems approach**, and this approach needs to be cascaded down with more detail to the Distribution FES and a concerted effort to bring forward further granularity of detail through Local Area Energy Plans, Community based Local Area Energy Plans and then down to Sub-station level Local Area Energy Plans. This strategic, vertically integrated planning approach must be developed if best value for the consumer is to be realised through an efficient process of reinforcements. The proposal by Ofgem to introduce 'Regional Systems planners' could facilitate this approach and use a deep understanding of the distribution network to understand and create local, place based solutions.

Some of the Rural grid is 'weak' and will not have the capacity to meet electrification requirements. The cost of reinforcing the entire rural grid would be cost prohibitive, take too long, not be a priority and there isn't likely to be sufficient workforce to deliver. The solution will be to create local; place based solutions where new demand is met by new generation in Smart Local Energy Systems (SLES). Local balancing, local flexibility, digitalisation, Active Network Management will all need to be deployed to ensure the best and most cost efficient solutions are developed. This cannot happen organically, or piece meal, but will need holistic, whole systems planning which will require adequate skill and resource.

Each area will have a different solution, however the process for finding that solution through planned as stated above, will be the same.

Each will have different assets that can be utilised. For example Cardiff and Liverpool have the potential to access offshore wind and Tidal Range. Manchester has the ability to access onshore wind. This potential should be reviewed and fed into the Local Area Energy Plans and how development would enable a stable, operable secure, decarbonised grid.

Great inroads have been made into decarbonising the grid, but with so many projects queued to connect to the grid, there is a tendency to complacency, when indeed, the hardest part is yet to come. Whole systems, holistic thinking, partnerships across TOs, DNOs, Ofgem, DESNZ, developers and indsutry must be tightened (so much easier now with roundtable gatherings being run via Teams etc) We are entering a period of innovation, but we must remember the fundamental physics of the grid, which will need to be powered by electrons generated from renewable energy. This generation needs to be dispersed across the country, across different areas of the grid and across many technologies.