Open letter on future reform to the electricity connections process

Closing date: 16th June 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

<table>
<tr><th></th><th>Hydropower:</th><th>Pumped Storage Hydro:</th><th>Tidal Range:</th></tr>
<tr><td>Potential deployable capacity</td><td>1GW</td><td>15GW`</td><td>13GW</td></tr>
<tr><td>What is the BHA calling for?</td><td>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</td><td>A cap and floor, to enable delivery of the 15GW called for in this CCC report</td><td>Regulated Asset Base, used for Nuclear, to enable delivery of 13GW</td></tr>
<tr><td>What are the main barriers to support?</td><td>Hard to raise relevance (seen as, too small, can't scale, too expensive)</td><td>Geographically constrained, market can deliver batteries</td><td>Too expensive (ie, Swansea Bay)</td></tr>
<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 kWhs 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>
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1. Introduction

The BHA welcomes the open letter and recognises the need for urgent reform, if the Grid is not to become the biggest barrier within the Net Zero transition. With new connection times being given for dates as late as 2045, the reality between the plan to meet targets and the actual Net Zero trajectory are wildly divergent.

The BHA recognises that:

"This must change – but it must change intelligently, given that we also know that the total contracted capacity exceeds ESO's predicted total future generation under every scenario in 2030 and the majority in 2050."

and highlights that installed capacity is no measure of how the grid will meet 'net demand/ resource adequacy'. We all know that increased flexibility across the grid will be key, but stability and operability of the grid within these parameters with a large part of generation coming from intermittent renewables, will be unchartered territory for the Grid operators.

The ability to build ahead of need will be a key enabler within the transition and the BHA also welcomes the recent Ofgem Consultations that have been deliberating Regional Systems planners and regional flexibility. Digitalisation must happen rapidly if we are to allow visibility and active network management that can recognise and maximise head room within the existing capacity. Smart local Energy systems at the distribution network will be vital, if the net zero transition is not to stall whilst we await transmission upgrades. (See local energy in Appendix A)

The BHA is hoping that the FSO will be able to be more directive about what technologies are needed to bring forward a stable, operable, decarbonised grid. Government's assertion that they need to be 'technology agnostic' and let the market deliver, 'lowest cost' for consumers has led to a distorted market and a grid that needs to curtail generation. A more strategic and less market led approach could have alleviated this problem many years ago.

Total installed capacity and GWs must make way for generation profiles and how they will meet future demand profiles.

The BHA are keenly awaiting further details about the FSO and the powers they may have and look forward to reading the Ofgem action plan and the Electricity Network Commissioner's recommendations.

2. Strategic Network Investment

This is welcomed and the speeding up of delivery is urgently needed. We should be prepared for considerable slippage of the proposed timeframe for the transmission upgrades and evaluation of slippage and mitigating plans must be reevaluated every 6 months to show impact on the pathway to reach a decarbonised gird by 2035. As suggested by the National Audit Office in their March report about decarbonising the grid, DESNZ does not have, but should urgently release, a delivery plan for the pathway to reach a decarbonised grid by 2035.

Focus of resource and finance at the Transmission network, must not eclipse the considerable amount of work that must be done at the distribution level across all voltages. Although the transmission issues cascade down and cause constraint at Distribution, there is much innovation that can be done at Distribution level, that can circumvent the current cessation of projects that happens when they have a statement of works.

3. Efficient and flexible network management

The BHA welcomes this approach but suggests that £166m to cover forecast costs to install monitoring equipment submitted by DNOS sounds a pitiful amount when this will be key between achieving Net Zero and stalling progress whilst the transmission grid is reinforced.

3.1. Digitalisation, Visibility and Active Network Management

On the distribution network, volumes of connection applications have also increased and are increasingly impacted by transmission constraints, reinforcement works and associated delays – even if there is spare capacity locally.[11] *This interaction requires improved coordination across the transmission-distribution interface.*

The above statement is a key statement and is the crux of the issue at Distribution level. We know there is spare capacity, but because the DNO can't 'see' it, they can't allow connections to take place. Digitalisation will allow visibility and AnM and, in part, will allow many of these issues to be resolved. Innovation funding and funding for enough resource to support innovation projects must be released by Ofgem and the DNOs must be persuaded to deliver further and faster in this space.

There are not enough innovation projects coming through. Funding is allocated competitively and there is no incentive to bring projects together through collaboration rather than competition. Innovation will save £Bns and yet the funds are meagre, take a long time to deliver and 'gateways' mean that many collaborators don't invest the time, as it's seen as costly and risky. This needs to change if we are to speed up innovation and delivery of innovations as rapidly as possible. Please see Case study in Appendix B.

4. The queue

The queue is market led and is there because it's a first come, first served, approach which leads to speculation and grid hogging. Projects can't move forward without an understanding as to whether they will have an affordable grid connection, hence, that is the first thing that a project will look to secure.

1. **Change the market**: This is being undertaken through consideration of Non-price factors and REMA. Project value should be considered much more holistically, including grid systems benefits rather than cheapest kWh that will continue to compound problems on the grid. Projects that will compound problems should receive less financial incentive.

2. **Prioritise physics over the market:** Consideration of overall grid benefits should be a key criterion within the queue. Projects that are going to be less impactful on the grid should be given priority. For example, a reservoir storage hydro should not be treated the same way as a solar farm, as the hydro will offer great operability and stability benefits over and above the solar.

3. **Remove the speculation** & re-prioritise the queue according to route to delivery – projects that have a defined route to delivery, with business plans, timeframes, milestones and likely route to financial close go to the top of the queue. The more developed the plan, the higher it scores. This should also be considered alongside the above point, where projects that are less impactful to the grid are also prioritise.

5. Technology agnostic

There is a friction between what is needed on the grid and the ideology that the market will deliver and has to be technology and projet agnostic. The Grid fits within the rules of Physics and is essentially a 'just in time' model of supply and demand. However, the rolling out of renewable energy projects is market led (as encouraged by the Government) which contradicts how any grid operator would set out and design a decarbonised grid.

For example, grid operators liek Hydropower and Pumped Storage Hydro on the grid, the stability and operability that it brings, however the Government has not favoured this technology as it's been deemed to be too small and expensive without the ability to 'scale up'. It therefore has not had an accessible incentive mechanism since Feed in Tariff and development has stalled in the UK. We know there is at least 1GW that can be delivered with a strike price of £140-£180/MWh and the BHA is asking the Government to amend the existing CfD to lower the >5MW parameter to >1MW (with the ability to aggregate pipelines of projects and ring fence as Hydropower can't compete with Solar and Wind). Hydropower gives stability to the grid and will be generating mostly over winter, including peak teatime demands. Currently Hydro offers 900GWhs of storage (compared to 27GWh of Pumped Storage Hydro) and this is dispatchable, low carbon generation. This hydropower is much cheaper than gas peaking plant ~£250MWh. There is more reservoir hdyro that can be developed and projects such as those described in the case study in appendix B must be given priority to operate and work to reduce overall cost to consumers through those wider grid benefits and ability to remove some of the issues with curtailed wind and enable better balancing. .

The BHA would like to encourage Ofgem to support Hydropower and request that the Government bring forward the 'tweaks' to the CfD that the BHA are suggesting, to mobilise this industry again and get the 1GW of hydro online, providing stability and operability to the grid including inertia and short circuit level which are increasingly rare as we move from synchronous to non-synchronous generation.

6. Pumped Storage Hydropower

There are currently 6.85GWs of planned PSH projects across a pipeline of 12 projects with over 135GWhs of storage. However, developers await the Government's decision on delivering a suitable long term price stabilising mechanism before a commitment to construct those projects can be made. The large capital costs, long investment period and complex revenue streams require a mechanism that ensures a minimum level of return can be achieved, most likely via a 'cap and floor'.

This decision is currently expected at some point in 2024. However, the BEIS committee in their recent report, 'Decarbonising the Power Sector', recommended that this decision is brought forward to 2023.

An accelerated delivery would help to address:

- **Investor flight:** global competition for investment, in particular the USA's Inflation Reduction Act and EUs 'Green Deal Industrial Plan', planning and consenting delays and unfavourable taxation via business rates are leading to the UK becoming less favourable as an investment destination. The cost of capital will be the primary factor determining the cost to consumers so **protecting access to low-cost financing should be a key driver in bringing forward this decision.**

- **Grid barriers:** Increased congestion on the grid is leading to curtailment costs of up to £62m per day according to the National Audit Office. **PSH can mitigate these costs by allowing for greater use of generation in constrained areas as well as reducing the need for costly**

grid reinforcement. If deployed, PSH could deliver system cost savings of up to £680m per year in 2050.

- **Congestion:** There has been an 8-fold increase **in the cost of managing congestion on the transmission network** since January 2010 and this trend is set to increase to up to £3bn per year by 2035 even after more transmission and distribution lines are built.

- **Rebalancing:** The Electricity System Operator (ESO) – originally envisaged as purely a residual balancer to reposition the market but is increasingly acting more as a central dispatcher, frequently re-dispatching more than 50% of demand (compared to only 10% in 2008).

- **Energy Security:** The recent energy price crisis demonstrated that the transition to clean, home-grown renewable energy is the only sustainable path to ending GB consumers' exposure to volatile fossil fuel prices. Unlike hydrogen or gas with CCuS, **PSH is a tried and tested technology that can deliver energy security by storing energy for when it is most needed, mitigating the variability of renewable generation**.

The lack of a cap and floor is therefore currently the only barrier to unlocking the huge benefits these projects will deliver for consumers and the economy. However, once delivered, with operational lifetimes of over 100 years, these assets will continue to provide these benefits for many generations to come.

7. Conclusion

To spread risk, we must have diversity, across our energy mix. Hydropower and PSH are proven, reliable and deliverable, with 80% of the supply chain in the UK. Both Hydropower and PSH are intergenerational assets (100+ years) that will deliver well beyond 2050 – true energy security. The wider systems benefits must be considered alongside 'cheapest' cost kWhs delivered as low cost does not always translate into best value for consumers.

The industry is poised to deliver and asks Ofgem to highlight to government that these key decisions that could begin the delivery of these critical infrastructural assets that will bring benefits across the grid.

8. Appendix A: Local energy

Even when the transmission network is reinforced, this will not resolve the issue that we have at lower voltages, which were never designed for electrification of heat and transport of rural communities.

1.1.1. The Grid & the Rural Net Zero Challenge

Grid constraints pose a major barrier to our Net Zero Transition. The Transmission constraint issues are being worked through via the Holistic Network Design and the £54Bn allocated to deliver both offshore and onshore reinforcements. This work is targeted to be delivered by 2030 (which is highly ambitious and based on precedent is very likely to have time slippage). Progress prior to these upgrades is going to have to focus on local flexible solutions. This will mean much more support should be focused on what can be delivered in the here and now, rather than in a time when the transmission grid is ready to deliver for Net Zero.

Much can be done at the distribution network level and focus needs to be on the constraints and solutions across the Rural Grid, which is the 'end of the line' in many areas and is classed as 'weak', meaning it may not have capacity for 'additional loads' to be added, i.e., electrification of heat and transport.

The Rural Net Zero transition poses a significant challenge to the Distribution Network Operators. The problem arises as the grid was designed for:

- Centralised generation, distributing electricity one way, with rural areas at the 'end of the line', often with the least demand.
- Rural areas often have lower electrical capacity to match their low demand, this does not make allowance for the ***total electrification of heat & transport*** required in the future.

Reinforcing the entire rural grid to enable and meet the total demand of electrification of heat and transport will be too expensive, take too long and will not be a priority due to low population density of rural areas.

- There is currently no policy support recognising the specific barriers of the Net Zero transition in Rural areas;
- This policy gap exposes Rural areas to the risk of being left behind and locked out of the Net Zero transition;
- The risk to rural areas unable to capitalise on the benefits Net Zero will bring: boosting the rural economy, jobs, skills, lower energy bills and warmer homes.

NB: Rural Broadband is a prime example of delayed policy that impacted and is still impacting Rural economies. We need proactive policy support to be ahead of the problem.

There must be an aspiration to create and deliver 'smart localised energy systems'.

- local energy consumption needs met through new,
    - small scale local generation,
    - storage and
    - Smart local energy systems,

These local smart solutions will circumvent the need for costly reinforcement, that may be triggered by the increased load of electrification of Heat and Transport. These smart solutions may offer a better 'value for money' solution and will take less time than reinforcing much of the rural grid to meet the additional loads required.

Policy support and funding is needed and could include:

- Local supply models and the local electricity bill.
- A scheme similar to the Rural Broadband project – which provided a Rural GigaBitt voucher scheme. A similar Rural Giga Watt scheme could enable roll out of low carbon heat.
- Provide funding for rural community scale local area energy plans.
- Contracts for Difference for Hydropower and other smaller, placed base generation that will be used to match increased rural demand for electrification of heat and transport.

Smart local energy systems will reduce the socialized cost of grid reinforcement; therefore, the incentive mechanism will pay back via avoided costs.

Community owned, locally owned renewable energy targets should be married up with incentives to deliver placed, based holistic smart local energy systems.

1.1.2. Street by street, Low carbon heat

Just transition means better health and wellbeing, less deprivation related mental health issues, better homes and lower bills.

The opportunity for low carbon heat and retrofit has yet to find a delivery model that can scale and bring the benefits of economies of scale, new jobs and skills, better, warmer homes and reduced bills. A community, street by street approach should be adopted that can bring a focal point for delivery and a replicable, scalable, inclusive model.

Examples include the Net Zero Terrace Street (Bacup, Rossendale), Barcombe Communtiheat, Chipping Community Energy and kensa's Stithians (heat the streets) These projects all adopt a whole community, holistic approach considering:

- Technical
  - Low carbon heat
  - Retrofit
  - Local energy generation
- Inclusive
  - Financial
    - No upfront capital cost.
    - Standing charge methodology – ideally situated on council tax bill.
  - Engagement
  - Local supply models

The impacts are already being felt with current energy crisis hitting those who are most vulnerable. The above holistic solution must be considered as a foundation for the Just Net Zero transition.

Incentive mechanisms, both current and past, have been designed to bring forward low cost energy. If we are to realise energy security, we need to review how and why we are incentivising and distorting the market. '**Low cost' does not mean 'best value'**.

The Levelised Cost of Energy has been used as the metric to determine what is the lowest cost of energy, we now need to move to a metric that is more nuanced that will allow us to understand what is 'best value'. The BHA are calling on the UK Government to use 'Enhanced' Levelised Cost of Energy as a metric that is more likely to show the 'actual' value of energy that takes into account multiple other factors that are going to deliver energy security and a just transition.

Community Hydro projects have the ability to unlock the Net Zero transition for many communities. As is the case for Ynni Ogwen, which is now looking at a Smart Local Energy System scheme. This project started as a community hydro scheme and is key in understanding how schemes bring local benefits, create collaboration and participation, lead to future Net Zero projects and engagement that enable proliferation of well- being and added value. This scheme was developed when the Feed in Tariff was available, there are currently no incentive mechanisms that can enable new schemes. Energy local is a local supply model that allows the community to buy energy generated from the hydro when it is generating. However, this is a complex regulatory issue and is hard to replicate. The BHA is supporting the Local Electricity Bill which would allow local supply models to flourish (as they do in Europe) and keep the benefits of local projects within the local community having a big impact on reducing fuel poverty and the switch to electrifying heat.

A Whole systems approach that undertakes a review of how each community will reach Net Zero and the new business models that can create a coordinated scaling up -eg, Case studies like Ynni Ogwen, Chipping Community Energy & Net Zero Terrace Street Net Zero Terrace SIF (enwl.co.uk) will be. The objective and methodology for a whole system, holistic approach must be defined at the earliest opportunity and a strategic plan for implementation delivered.

9. Appendix B – case study highlighting the issue at Distribution level arising from lack of digitalisation, visibility and AnM

Case Study: Allt na Moine Hydro

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 requires 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.

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 not to be eligible for constraint payments. They will be the first generators to be temporarily excluded from grid access and will receive no 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.

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 power house, a low visibility, low impact scheme that will generate for 100+ years (true energy security)

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.