Supporting Hydropower's Transition from the Renewable Obligation Certificate

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1. BHA Overview

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 industry and local communities.

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

2. Executive Summary

The objective of this paper is to demonstrate to Government the reasons why there is a need to ensure there is continuity of the Renewable Obligation Certificate for hydropower, with a clear exit strategy, in lieu of suitable market mechanisms required to ensure ongoing revenue certainty for the existing UK hydropower fleet.

The BHA is advocating for urgent government action to ensure continued revenue stability for UK hydropower assets as they transition away from the Renewables Obligation (RO) scheme. Without intervention, hydropower schemes face a significant revenue cliff-edge, threatening their viability, despite their critical role in energy security, grid stability, and the ambition to decarbonise.

The Case for Hydropower

- **Reliable, Low-Carbon Power**: Hydropower provides firm, dispatchable electricity, reducing dependence on fossil fuel peaking plants.
- **Seasonal Alignment**: 70% of UK hydropower generation occurs in winter, complementing energy demand patterns.
- **Long-Term Asset**: With a lifespan exceeding 100 years, hydropower outlasts wind and solar, requiring fewer repowering investments.
- **Grid Stability**: Hydropower enhances frequency response, inertia, and voltage control, reinforcing the UK's energy infrastructure.

Challenges & Revenue Cliff Edge

- Hydropower assets transitioning off the ROC scheme face sharp revenue declines, making continued operation unsustainable.
- The existing energy market undervalues hydropower, as wholesale price-determined PPA are distorted by transmission connected gas and large-scale solar/wind receiving Contracts for Difference (CfD) subsidies. PPAs are forecast to remain low, and with rising inflation and increasing operational costs, the operational revenue is squeezed beyond viability.
- The loss of revenue could lead to the decommissioning of essential hydropower schemes, undermining the UK's net-zero ambitions.

Proposed Solutions & Policy Recommendations

1. **Continuity Bridge ROC Tariff**: A five-year transitional period to provide revenue stability and certainty while market mechanisms are reformed, or formed (giving a clear exit strategy for this ROC bridging tariff)
2. **Capacity Market (CM) Reforms**:
    - Establish a premium for low-carbon dispatchable generation.
    - Adjust contract terms to support hydropower participation.
    - Accelerate the introduction of a suitable "Minima" mechanism to prioritise proven renewable capacity.
3. **Formation of Local Energy Markets**: Support distributed generation and fair valuation of hydropower's contribution at the distribution network level.
4. **Enhanced Tax Incentives**: Enable hydropower schemes to modernise, integrate storage, and digitalize operations to align with future grid needs.

Strategic Shift Required

To maintain hydropower's role in a net-zero energy system, government action is critical. Immediate steps include:

1. Conducting a survey of existing hydropower schemes to assess the impacts of the RO expiration on existing hydropower systems.
2. Implementing reforms to market mechanisms to provide fair value for hydropower in a decarbonised grid.
3. Supporting hydropower enhancements that can replace gas peaking plants and contribute to energy resilience.

Without intervention, and due to market failures, the UK risks losing a fleet of valuable renewable assets which have many years of operation remaining. A structured transition with financial mechanisms and regulatory support is essential to ensure hydropower remains a cornerstone of the UK's future energy mix.

3. Why Hydropower is important

- Reservoir hydropower offers firm, dispatchable, and long-lasting power generation and can act as a low-carbon alternative to fossil fuel peaking plants.
- 70% of UK hydropower generation occurs in winter, aligning with periods of high energy demand.
- Unlike solar, which generates mostly in summer, hydropower provides electricity when the grid is under the greatest strain during cold, dark winter months.
- Hydropower reduces reliance on gas-fired power plants, which currently dominate the UK's backup energy supply.
- Hydropower provides Grid Stability, as it produces inertia, frequency response and voltage control.
- Long-Term Energy Security - hydropower plants last over 100+years, whereas wind and solar require repowering every 25-30 years.
- Hydropower reduces dependence on imported fuels, as it is domestically generated and independent of volatile global markets.
- The UK currently has 2GW of installed hydropower capacity, with an additional 1GW of untapped potential that could be deployed within 5-7 years.
    - Replacing just 1GW of gas peaking capacity with hydropower could save millions in emissions costs and stabilise electricity prices.
- Hydropower is proven, reliable and has low deliverability risk.

Security comparison:

- Gas-fired plants depend on volatile fossil fuel prices and imports.
- Hydrogen-fired power depends on an emerging global market with uncertain costs and supply.
- Hydropower is stable, local, and intergenerational.

Example: During the 2022 Energy Crisis, UK hydropower saved consumers £1.1 billion by providing reliable, low-carbon power at peak demand times.

Financial comparison:
- Gas peaking plant with CCS: ~£250/MWh
- New hydropower strike price: ~£140/MWh (£102/MWh 2012 prices)
- Existing hydro: Much cheaper, as infrastructure is already in place.

4. The Renewable Obligation

The Renewables Obligation (RO) is a market support mechanism designed to encourage generation of electricity from eligible sources in the UK

- The RO replaced the Non-Fossil Fuel Obligation which operated from 1990
- Introduced in England, Wales and Scotland, April 2002
- Introduced in Northern Ireland, April 2005
- Each form of renewable energy technology received the same level of support, one ROC/MWh of electricity generated
- Banding was introduced in 2009 to provide differing levels of support to groups of technologies depending upon their relative maturity, development cost and associated risk
- The RO closed to new hydropower March 2017
- The 'early years' generators (amongst the first to be accredited under the RO) retire from the scheme in 2027. The RO will close entirely in 2037. UKG paper link.

5. Urgency – Schemes coming off ROCs face a revenue cliff edge

Over the next few years, hydropower schemes will be retiring from the Renewable Obligation scheme and will see a sharp cliff edge within their revenue. (**See Appendix A**) Market failures ensure that green electrons generated across the distribution network are still not given adequate value (especially those generated at peak times) within the skewed wholesale market that does not yet value 24/7 green power/ demand matching. With the cost of inflation affecting operation and maintenance costs, there is clear concern within the industry that schemes will become too expensive to run.

The UK's hydropower fleet remains a valuable and enduring national asset, with infrastructure lifespans that often exceed 100 years. These schemes have witnessed the rise and fall of successive new technologies such as coal, nuclear, gas, and now early wind farms, and throughout this period, hydropower has continued to generate consistently in the background. Many of these schemes provide dispatchable capacity, often during periods of peak demand in winter, and critically when wind output is low and solar generation is at its lowest.

Despite these attributes, a combination of deteriorating revenue certainty and rising input costs means that post-RO viability is now in question for many operators. A detailed case study covering Belper, Burton and Masson Mills (**see Appendix B**) illustrates the challenge clearly. Even where plant continues to perform well, the removal of ROCs, combined with modest export prices, renders many schemes only marginally viable or entirely loss-making under current market conditions. The operator, Derwent Hydroelectric Power (DHP), identifies options such as increased on-site use and flexible dispatch, but notes that structural market support, such as a temporary extension of ROCs or a replacement mechanism, is likely to be essential for long-term viability.

The UK hydropower sector must be recognised as part of the future decarbonised electricity system. This means securing a stable, long-term revenue model that reflects the true system value of clean, locally generated power, especially during times of system stress. Without such measures, the risk is not only the loss of generating capacity but also the erosion of a legacy industry whose contribution to the energy transition remains under-recognised and under-rewarded.

6. Existing Hydropower fleet on ROCs

Hydropower schemes do not need repowering; they require a stable revenue stream to ensure continuity, alongside an enhancement tariff to enable them to be ready for the needs of the future grid.

Operational costs have increased due to inflation, but baseline wholesale prices have remained static. When schemes leave the ROC, they will be dependent on PPA prices or day ahead prices set by a distorted wholesale price market, which is determined by transmission connected gas, solar and wind underpinned by a government backed CfD**.** There is a market failure that must be addressed, otherwise Hydropower is at risk of being switched off or, worse, decommissioned and removed.

The table below gives the data showing when certain hydropower schemes were added to the RO register (which includes ROCS and FITs).

Table 1 – Table showing when Hydropower schemes were registered on the RO

	1-2MW		2-5MW		> 5MW		All>1MW	
	Count	TIC	Count	TIC	Count	TIC	Count	TIC
2002	1	1	3	10	2	38	6	49
2003	8	11	9	29	24	343	41	383
2004	2	3	8	27	5	94	15	123
2005			4	10	2	34	6	44
2006			-	-	1	8	1	8
2007			1	3	-	-	1	3
2008			1	3	18	962	19	965
2009	3	4	1	3			4	7
2010	2	3					2	3
2011	2	3					2	3
2012	2	4	1	4			3	7
2013	1	1	1	4			2	5
2014	2	3					2	3
2015	7	11					7	11
2016	14	22	1	3			15	25
2017	11	20					11	20
2018	-	-					-	-
2019	2	4					2	4
2020	3	6					3	6

2021	6	11					6	11
Total	**66**	**106**	**30**	**94**	**52**	**1,479**	**148**	**1,679**

See Appendix C for full details of ROC costs and hydropower's contribution to household bills

7. What does the Government need?

As more intermittent renewables come online, gas will be pushed to the margins with a much-reduced capacity factor which will push up the price to maintain and operate peaking plant. The swings between maximum prices and minimum prices (negative pricing) will increase market instability. The UK grid will continue to see higher prices when we see prolonged periods of low wind. On the 8th January 2025, there was a high-pressure system over the UK which pushed up the whole sale price to £1,353/MWh. During this period, hydropower was delivering 1.13GW of power, alongside Pumped Storage Hydropower providing 1.5GW.

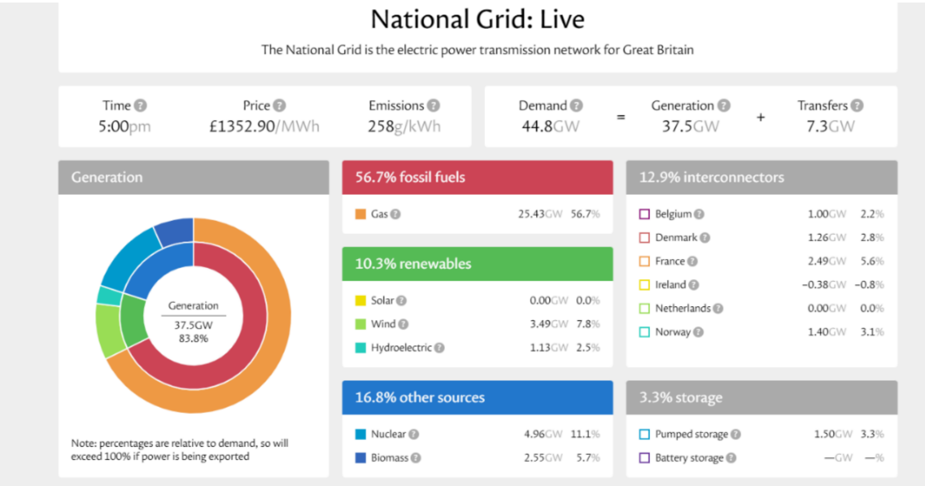

Figure 1 – Energy mix on 8th January 5pm

8. What can Hydropower provide for the grid

8.1. Unlocking New Capacity

A Birmingham University Hydropower resource assessment report undertaken in 2022 detailed the potential to deploy a further 1GW of capacity at a strike price of £140/MWh. This is significantly more cost-effective than developing new gas peaking plants, which hydropower could displace during periods of system stress. With its ability to generate on demand, this additional hydropower capacity could offer low-carbon flexibility to the grid at a fraction of the cost of fossil alternatives.

8.2. Distribution Network Resilience

Over the next 15 years, the UK grid will shift towards a highly decentralised system, dominated by variable renewables such as wind and solar. This transformation will require large-scale integration of storage technologies (including pumped storage, batteries, and thermal storage), greater demandside flexibility, and a more intelligent, digital grid with full visibility across high- and low-voltage networks. As electrification accelerates in heating, transport, and industry, the pressure on local distribution networks will increase. This transition will depend on smart local energy systems capable of balancing generation, demand, and storage close to the point of use. Hydropower, particularly in rural and remote areas, plays a vital role in this future grid architecture. It provides essential grid services at the distribution level, including voltage support, inertia, constraint management, and local resilience.

8.3. Enhancing the Existing Fleet

Much of the UK's existing hydropower fleet, particularly schemes built under the ROC and FiT regimes, was not designed with integrated storage. Generation-based incentives meant that reservoir development was often excluded from project designs due to cost and complexity, despite its current relevance to system needs

This creates an opportunity: with the right support, many of these sites could be enhanced through retrofitting additional storage. Options include expanding existing reservoirs, installing inflatable rubber dams, or increasing catchment areas to boost capacity. Where storage retrofits are impractical, battery co-location offers an alternative. Further opportunities lie in automation and digital control, enabling hydropower schemes to interact more dynamically with the future grid.

8.4. Gas at the Margins

Expanding and modernising the hydropower fleet can reduce the need for new gas peaking capacity. An additional 1GW of hydropower, equipped with enhanced or co-located storage, could deliver dispatchable, renewable electricity during peak demand periods. Hydropower already operates during the same peak windows as gas peaking plants, as illustrated in Figure 2. Targeted investment in new and optimised hydropower would allow the grid to meet peak demand without locking in high-emission, high-cost gas infrastructure.

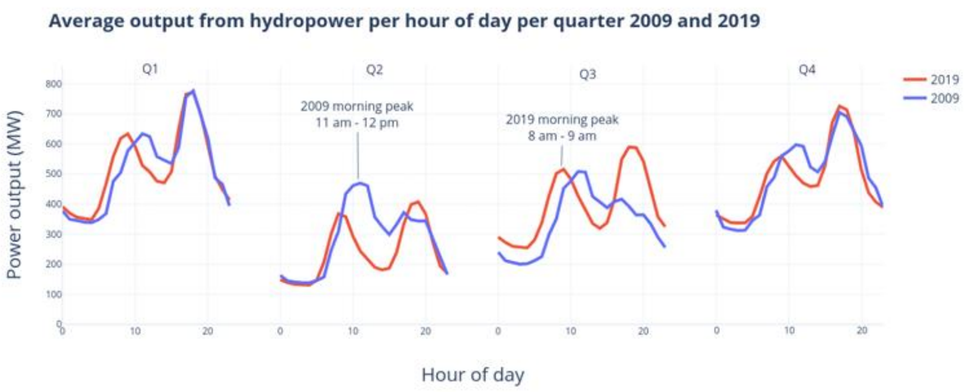

Figure 2 – hourly average of generation for hydropower from Elexon values

9. Mechanisms to support existing and new Hydropower

9.1. The Capacity Market

The Capacity Market was set up to provide resource adequacy rather than a decarbonised grid and is therefore misaligned with the changing energy system and the UK's Net Zero goals and must urgently be reformed. The CM, in its current form, is insufficient for ensuring future energy security, decarbonisation, and grid stability.

9.1.1. Why the CM needs reforming

See Appendix D for a more detailed explanation of the Capacity Market and Hydropower

1. The Current Market Does Not Support Net Zero Goals

- The CM was initially designed to secure capacity adequacy, primarily relying on gas-fired generation.
- 67% of current CM capacity is gas, with the expectation that hydrogen and carbon capture, utilisation, and storage (CCUS) will replace unabated fossil fuel generation.
- Hydrogen and CCUS are not yet proven at scale, making reliance on them a significant risk.
- The CM's structure does not sufficiently incentivise long-term, low-carbon, dispatchable energy sources such as reservoir hydropower.

2. Over-Reliance on Unproven Technologies Increases Risk

- The government's approach assumes hydrogen and CCUS will scale up quickly, yet:
    - Hydrogen production, storage, and transport are inefficient and costly.
    - CCUS has uncertain capture rates and cost-effectiveness.
    - Global hydrogen markets may replicate fossil fuel price volatility, creating new risks.
- Meanwhile, proven low-carbon technologies such as hydropower are being overlooked, despite their long lifespan and reliability.

3. Lack of Long-Term Investment in Secure, Low-Carbon Energy

- Hydropower offers 100-year operational lifespans, compared to wind and solar, which require repowering every 25 years.
- Despite this, the CM does not provide:
    - Long-term price signals for hydropower.
    - Mechanisms to encourage firm, low-carbon energy storage.
- Without reform, short-term thinking will lead to increased costs and volatility for consumers.

4. No Clear Plan for Transitioning Away from Fossil Fuel Peaking Plants

- Peaking plant (gas turbines) will become less efficient as their capacity factor decreases and they run fewer hours, raising costs for consumers.
- The CM does not include a clear mechanism to transition peaking capacity to low-carbon alternatives.

9.1.2. Low Carbon Dispatchable Generation Premium

The Capacity Market must rapidly evolve and give a premium to low carbon dispatchable power.
It must ensure:

- There is encouragement to move away from gas.

- Auction times run differently from the current T4 & T1 auctions to include T7-10.
- Longer term support (if this mechanism is to bring new hydropower generation forward)
- Enhancement support – if the CM is to encourage enhancement through refurbishment to enter the CM.

9.1.3.Minima

During February 2024's consultation on the ongoing Review of Electricity Market Arrangements (REMA), the government at the time proposed a 'Minima', a minimum procurement target within the Capacity Market auction to better support investment in low-carbon flexible technologies. This proposal was introduced in response to the challenge of transitioning away from an unabated gas-based system towards a flexible, resilient, and decarbonised electricity system.

The Capacity Market would continue to operate through a single auction process; however, under the Minima proposal, it would feature multiple clearing prices. This would allow for the introduction of a minimum procurement target for desirable characteristics, ensuring that a set amount of capacity from specific technology types is secured. The auction would incorporate a mechanism to enable different clearing prices to be determined for these desirable characteristics, which could include low-carbon generation, long-duration storage, or other key flexibility capabilities.

At present, Minima remains under discussion within the government, with ongoing deliberations over how the Minima should be defined and implemented. Key questions include whether it should prioritise capacity that is strictly low-carbon, focus on specific flexibility characteristics such as fast response times or long-duration storage, or adopt a hybrid approach that balances both aspects.

Additionally, consideration must be given to how these targets interact with existing Capacity Market rules and how they influence investment signals for emerging technologies.
By establishing a guaranteed level of procurement for technologies that contribute to system flexibility and decarbonisation, the proposal could provide a stronger investment case for hydropower and other renewable technologies that have traditionally faced barriers to market entry. However, several risks and challenges must be addressed in its implementation, and there are several ways in which the Minima can be implemented that would make it successful for Hydropower and decarbonising the Capacity Market:

- **High Clearing Price-** in the 2024 T-4 auction, the clearing price was £65kW. This needs to be considerably higher in order to attract new investment.
- **Making the Minima only available for reliable and proven (TRL9) low carbon dispatchable technologies-** there is a danger that the Minima may be absorbed by emerging technologies via T4.

It is also important that the Minima is brought forward quickly and efficiently. If the Minima is stuck within the REMA reforms, it risks coming in too late for many Hydropower installations as the end of the Renewable Obligation comes into effect, or even after the proposed Continuity ROC finishes.

9.1.4. Proposed Reforms for the Capacity Market

To better align with Net Zero, energy security, and affordability, the CM must be restructured to:

1. Incentivise long-term, low-carbon storage solutions such as hydropower.
2. Ensure the introduction of the 'Minima' provides a high enough strike price to make it competitive to both introduce new Hydropower as well as bring on board existing hydropower.
3. Extend CM contracts for longer construction lead-time projects, such as PSH and hydropower.
4. Facilitate entry for new low-carbon projects, including hydropower schemes from 1MW.
5. Reform the emissions limits in the CM to phase out unabated fossil fuel generation sooner.
6. Consider Technology Readiness Level and deliverability risk. There should not be reliance on emerging technologies like generation from hydrogen and abated gas with CCUS, which are unproven at scale, over reliable, proven technologies being brought forward, such as Hydropower.

9.2. Schemes not suitable for CM

For smaller schemes that will not be suitable for the CM, there is the potential that they will be able to access 'uplifts' through Local Energy Markets (Appendix E). Balancing and settlement Code modifications P441 and P442 offer potential to precipitate local energy markets, however, this is very nascent and cannot be considered a suitable alternative at this time, although a review in 3 years could reveal significant market growth offering a route to market for existing and new schemes.

However, until such time, the Continuity ROC is essential.

10. Solutions – the Continuity ROC & Enhancement Incentives

10.1. Continuity ROC

As schemes come to the end of the ROC there is a revenue cliff edge that needs to be urgently addressed. The BHA are proposing a continued **Renewable Obligation Certificate,** to prevent existing hydropower assets from facing a hard stop. The ROC Continuity Bridge would provide a 5-year extension (with a 3-year review window) which would enable operators to remain generating as well as plan for a transition away from the ROCs and give the Government time to adjust existing mechanisms that can then accept the Hydropower fleet and ensure continuity of operation.

10.2. Enhancement tax incentives

The existing hydropower fleet will need a business case to enable refurbishment & enhancement to ensure continuity as a key part of the existing network infrastructure and to future proof for the next 50 years of a smart flexible grid. Digitisation will be required to participate in both the CM and Local Energy Markets and will enable optimisation / balancing and flexibility. The BHA will work with operators to review the existing hydropower fleet and determine how schemes can be enhanced, what will be the **cost to refurbish and enable the fleet to be 'optimised and sweated'.** Please find more information on other enhancement schemes in Europe in Appendix F.

11. Conclusion: The Need for a Strategic Shift

The Renewable Obligation Certificate was designed to support new renewable energy generation to compete in a skewed energy market, over the lifetime of the asset. However, hydropower has a far longer lifetime than other renewable energy technologies. Whereas solar and wind will look to repower, hydropower can continue but would benefit from refurbishment.

The energy market is still heavily distorted, with wholesale prices driven by transmission connected large scale gas, solar and wind, that are underpinned by government backed CfD. Hydropower does not receive the value that represents its importance as a winter generator, generating across peak demand. Government needs to address this market failure, yet the mechanisms that could do this correction are currently not set up to do so.

- The Capacity Market must evolve from a system that supports gas and unproven technologies into a long-term, risk-managed framework that prioritises energy security, affordability, and decarbonisation.
- Local Energy Markets must be brought forward to assist the uncoupling of distribution connected schemes from the Transmission led wholesale price market, so those schemes are valued in their location where they bring benefit.

Hydropower's savings to the taxpayer in the past and the future (See Figure 3) justify the need to ensure that hydropower continues to play an active role in the energy grid, now and into the future, and until these market mechanisms are able to deliver the revenue that matches the benefits that Hydropower brings to the grid and the UK, there needs to be a ROC Continuity Bridge (alongside a clear exit strategy of developing and delivering on CM and Local Energy Markets) with incentives that can enable the hydropower fleet to be fit for the next 20 years.

Figure 3: Hydropower savings to the taxpayer

Item	Estimated National Impact	Cost or Saving	Notes
2022 Energy Crisis	£1.1 billion saved	~£400 per householder	Hydropower helped displace gas at peak demand times
Annual Grid Constraint Payments	~£1.5 billion	~£15 per householder	Mostly due to curtailment of wind/gas
Hydropower's Role in Constraint Management Zones	Deferred reinforcement & peaking plant	Likely £millions	Site-specific data from SSEN, WPD, SPEN pilots

Next steps

- A Government Survey of all hydropower schemes currently on ROCs to detail the impact of the ROC ending.
- Request information from scheme owners as to whether they can transition to the CM – recognizing that the admission process is currently set within rounds which may not be able to accept the Volume of hydropower that will need to transition.
- Offer a 5-year continuity tariff with a review window at 3 years to determine progress to other mechanisms.
- Continue to work on alternate market mechanism schemes:
    - Capacity Market reform
    - Local Energy Market acceleration.
    - Enhancement tax incentives to ensure Hydropower is fit for the future grid.

12. Appendix A: Hydropower Exemplar Case Studies

This appendix presents two anonymised case studies provided by members of the British Hydropower Association. These examples illustrate the typical income, costs, and financial pressures faced by small- and medium-scale hydropower schemes in the current market. All figures use early 2024 power prices and exclude interest on loans and tax, which can materially affect cash flow.

Case Study 1: Non-Dispatchable Run-of-River Scheme (0.5MW–1MW)

This example covers a non-dispatchable run-of-river hydropower plant with a capacity between 0.5MW and 1MW. The scheme operates without the ability to respond to market signals and is dependent on consistent water flow. The figures below are indicative of its current and potential future financial position.

Current Financials

- **Annual Revenue**: £400,000
- **Operations & Maintenance (O&M) Costs**: £85,000
- **Net Cash Flow**: £315,000

Projected Future Financials

If wholesale power prices fall or support mechanisms are withdrawn:

- **Annual Revenue**: £200,000
- **O&M Costs**: £85,000 (assumed unchanged)
- **Net Cash Flow**: £115,000

Financial Impact

The drop in revenue leads to a £200,000 reduction in annual cash flow — a decrease of around 63%. This estimate assumes O&M costs remain flat, which is unlikely given inflation and ageing infrastructure. Additional costs such as tax and financing are also not included here, meaning the real cash flow impact could be even more severe.

Case Study 2: Dispatchable Storage Scheme (Over 5MW)

This second case focuses on a larger, dispatchable hydropower plant with storage capability and a capacity exceeding 5MW. These plants provide flexibility to the grid by storing and releasing water in response to market demand. However, they face complex financial challenges, especially when exiting the Renewables Obligation (RO).

Indicative Revenue (10MW Plant Example)

- **Pre-RO Exit Total Revenue**: £2.2m (includes ROCs)
- **Post-RO Exit Revenue Loss**: Around 46%
- **Estimated Post-RO Revenue**: £1.2m
- **Capacity Market Payments**: £400,000 (at £40/kW/year for 10MW)

Indicative Costs

- **Annual O&M Costs**: Approximately £500,000
    - Includes business rates, routine maintenance, day-to-day capital items, and minor renewals

Cash Flow Impact

- **Pre-RO Exit Net Cash Flow**: £2.2m – £0.5m = £1.7m
- **Post-RO Exit Net Cash Flow** (including capacity payments): £1.2m + £0.4m – £0.5m = £1.1m
- **Reduction in Cash Flow**: £600,000 or approximately 35%

Long-Term Considerations

Many dispatchable plants face major refurbishment costs, such as dam or intake repairs, typically required every 20 years. These costs can range from £5m to £20m. With reduced and more volatile revenue, and annual net income around £1.1m, the payback periods for major reinvestment become prolonged and uncertain.

Conclusion

Both case-studies demonstrate that even well-performing hydropower assets face significant financial risk as they lose access to legacy support schemes. Without intervention, such as targeted tax relief for capital enhancements or a stable price support mechanism, ongoing investment in these schemes becomes increasingly difficult. Financial certainty is critical to ensuring these valuable assets continue to operate safely, efficiently, and in support of the UK's net zero goals.

13. Appendix B: Belper, Burton & Masson Mills ROC Case Study

Derwent Hydroelectric Power (DHP) owns and operates a portfolio of 16 hydropower sites across England and provides services to other generators ranging from O&M to consultancy and project delivery. Among these, three sites, Belper Mill, Burton Mill, and Masson Mill, are facing a critical juncture: the end of Renewables Obligation Certificate (ROCs) support in March 2027.

Site Histories and Technical Overview

Each of the three sites has a legacy of harnessing waterpower that spans centuries:

- **Belper Mill**: Dating to 1776 when Jedediah Strutt built his pioneering cotton mill, the site has been generating for export since 1999. It houses two 1950s Gilkes pit Francis turbines that remain operational, albeit with significant maintenance needs. Over the last 10 years, the site has generated 16.6 GWh of electricity
- **Burton Mill**: With milling activity on site since medieval times, DHP began generation here in 1997. It uses a 1930 Francis turbine, now the oldest in the portfolio, and has the lowest generation output. In the last 10 years, the site has produced 1.3 GWh of electricity.
- **Masson Mill**: Arkwright's 1783 development on the Derwent has seen continuous use of waterpower, with electricity exported to the grid since 1995. The 1974 Gilkes turbine is the most modern of the three and benefits from partial on-site electricity use. In the last 10 years, the site has generated 7.3 GWh of electricity

Financial Analysis Post-ROCs

With ROCs support ceasing in 2027, DHP analysed viability based on historical average generation, forecast export prices, and realistic O&M costs. Masson Mill is the only site that currently shows positive net value due to its ability to offset grid import costs via on-site electricity usage.

Table 1: Financial Summary of Belper, Burton and Masson (No ROCs, Current Operation)

	Belper	Burton	Masson
Income			
Average Annual Energy Production	1,650 MWh	120 MWh	735 MWh
Typical Export Value	£85/MWh	£85/MWh	£85/MWh
Site Usage Displacing Import	–	–	25%
Site Value per kWh	–	–	20.0p
Revenue / Value Forecast	£140,000	£10,000	£84,000
Costs			
Planned O&M	£41,000	£4,000	£15,000
Repairs / Reactive O&M	£33,000	£6,000	£9,000
Consumables & Expenses	£12,000	£1,000	£4,000
Rent, Fees & Charges	£54,000	£5,000	£9,000
Total Costs	£139,000	£16,000	£38,000
Net Annual Income/ Value			
	£1,000	**-£6000**	**£46,000**

Export prices are forecast to decline over the coming years, making future viability even more challenging. While Belper may remain marginally viable under optimal conditions, any major breakdown or repair would render it loss-making. Burton is already considered unviable under current projections.

Mitigation Options

DHP reviewed a series of strategies to keep these sites operational:

1. High-Quality Maintenance: Essential to avoid catastrophic breakdowns, especially given equipment age.
2. Licence Exempt Supply: May offer future benefit through local energy markets but remains uncertain and early-stage.
3. Flexible Dispatch: Requires storage or market access that most small hydro sites lack.
4. On-Site Usage / Private Wire: Valuable but applicable only to a minority of sites like Masson.
5. Price Support: The most effective option, via Hydro FIT reinstatement or ROC extension.

Masson Mill: A Closer Look

DHP is actively working to increase on-site electricity consumption at Masson Mill through redevelopment of the adjacent shopping village. If usage rises from 25% to 80%, the site's net annual value could almost double.

Table 2: Masson Mill Financials Under Higher On-Site Usage Scenario)

	Masson	**Masson Increased on Site Usage**
Income		
Average Annual Energy Production	735 MWh	735 MWh
Typical Export Value	£85/MWh	£85/MWh
Site Usage Displacing Import	25%	**80%**
Site Value per kWh	20.0p	20.0p
Revenue / Value Forecast	£84,000	**£130,000**
Cost		
Planned O&M	£15,000	£15,000
Repairs / Reactive O&M	£9,000	£9,000
Consumables & Expenses	£4,000	£4,000
Rent, Fees & Charges	£9,000	£9,000
Total Costs	£38,000	£38,000
Net Annual Income/ Value		
	£46,000	**£92,000**

The Case for ROC Extension

A temporary extension of ROCs support, such as the 2031 extension recently granted to Drax, would provide a critical lifeline. This would allow generators to bridge the gap while market reforms or replacement mechanisms are developed. Importantly, many existing ROC-accredited sites were themselves refurbished to qualify, suggesting a policy precedent.

Table 3: Notional Financials with Continued ROC Support

	Belper	Burton	Masson
Pre ROC Net Annual Income/ Value	£1,000	-£6000	£46,000
Notional ROC's at £67.00/MWh	£111,000	£8000	£49,000
Notional net income with ROCs	**£112,000**	**£2000**	**£95,000**

Conclusion

Belper, Burton and Masson Mills have collectively produced over 25GWh of clean electricity in the last decade, enough to power the UK for an hour on a mild day. Without intervention, this generation capacity and the heritage it supports could soon be lost. DHP's analysis shows that while site-specific measures may provide temporary relief in a limited number of cases, policy action remains essential to safeguard this legacy and its contribution to net zero.

14. Appendix C: The Cost of Hydropower in the Renewable Obligations Scheme

The Renewables Obligation (RO) requires licensed electricity suppliers to source a proportion of the electricity they supply to UK customers from renewable sources.

Initially each form of renewable energy technology received the same level of support, one ROC/MWh of electricity generated. Banding was introduced in 2009 to provide differing levels of support to groups of technologies depending upon their relative maturity, development cost and associated risk.

The obligation levels for 2023-24:

- 0.469 Renewables Obligation Certificates per MWh of electricity supplied to customers in England, Wales and Scotland.
- The buy-out payment per Renewables Obligation Certificate = £59.01

With this in mind, Hydropower only accounts for around 724 MW of capacity out of 35GW accredited under the Renewables Obligation (RO), equating to roughly 3% of total supported generation capacity.

In terms of Renewable Obligation Certificates (ROCs) awarded, these technologies received approximately 2.39 million out of 107.4 million ROCs issued, again, around 3%, taking account of actual generation and load factors.

Given that the RO added an average of £89 per household to energy bills in 2025, this would imply that hydropower contributed less than £2.67 per household per year.

This can be compared to the costs of constraints which in the financial year 2022-23, cost £1.5bn, which adds about £15 / year to a typical domestic consumer's bill.

Hydropower alleviates constraints through storage and helps Constraint Management Zones. Reducing the amount of hydropower on the network is likely to cost the consumer more in network and constraint costs than the current small price of the ROC.

15. Appendix D: Capacity Market and Hydropower

The Capacity Market pays schemes to be 'available' to meet times of grid stress. It was set up 12 years ago and is now outdated and overdue reform. (There have been some initial consultations, and we are expecting another one shortly).

Schemes need to have a total installed capacity of 2MW or above, although there is the ability to aggregate across a portfolio. Schemes can't apply if they are on ROCs/FiTs or CfD. Schemes that are in the CM don't have to increase generation during a CM event; they just need to maintain the level that they've been entered at. The level they are entered at will depend on the derating factor, which is high for hydropower. For example, 3MW scheme will have a derating factor added at 90% so is entered into the market at 2.7MW. That's the obligation they need to meet and will get paid during a capacity market event. Schemes need a high level of accuracy in terms of monitoring and there can be challenges around costs in telemetry.

In the 2023 auction for the 2026/2027 delivery year, SSE renewables secured contracts for de-rated Hydro generation and Pumped Storage Capacity in the T-4 Capacity Auction for a one year contract. The contract included nearly 906MW across 26 units, including Sloy Hydro and the Pumped Storage at Foyers. SSE also secured further contracts in the 2024 auction.

The Capacity Market has the potential for Reservoir (and possibly run of river) Hydropower and Pumped Storage Hydropower, providing stable finance for existing and new facilities. However, many Hydropower installations have the capacity to turn into Reservoir Hydropower or to enhance its dispatchable capabilities, but the CM does not take this into account. Therefore, **providing support for enhancements required to join the CM** would allow more Hydropower to enter.

Another change that would be welcomed would be either utilising either **3-, 9- or 13-year contracts for existing Hydro generation.** Given the lengthy admission process, and the need to apply several years in advance, only 1-year contracts (or 3 if significant refurbishment is needed) are not sufficient for most generators, and by extending the contracts by a 3-year period would encourage more uptake of the scheme by hydropower generators.

16. Appendix E: Local Energy Markets

Focus (post FIT) has been on Transmission connected schemes brought forward with CfD. The market has created distortions which has meant that Embedded generation (tied to the wholesale market prices) has been unable to find a bankable business model. This is a market failure which is stymieing new generation at the distribution network.

Focus needs to shift to Distribution network connections – last 20 years has valued Total Installed Capacity and mass generation, next 20 years **must focus on Smart Local Energy System** – asset value within SLES not generation value in isolation. We need to move towards 24/7 matched green power (across distribution 'nodes')

16.1.1. Local Energy Markets

Create local energy markets to bring together generators, flex and consumers within a distribution area and provide a market that unlocks the value of balanced supply and demand at distribution level:

- Need to uncouple from wholesale prices (set by Transmission connected Government backed large scale schemes) in times of oversupply
- How can we unlock LEM values which will provide sufficient revenues to enable new distributed generation and storage to be built and provide savings to consumers?
- How can we create a floor price that is created within the LEM that will derisk schemes and enable them to raise finance?
- How do we create a long-term ceiling price which manages risk for consumers.

16.1.2. Energy Local Model

Class A exempt supply under modification P442 and pending P441 provide a significant and useful starting point to unlock the value of local energy markets

- Value of P441/ P442 (green levy removal (P442/P441)) and reduction of UoS charges (P441)
- However licence exempt is only up to 2.5MW (per HH) and limits are not per project, but per company
- P442 has nongeographic boundaries and could be rescinded. Grandfathering for operational projects would give confidence to new projects raising finance against P442, where they would not be viable without it.
- Proximity of generators and consumers will offer the most market value if UoS charges can be monetised and LEMs can unlock the value of flex.

16.1.3. GB Energy

With the remit of the Local Power Plan to deliver 8GW of local energy, GBE is working hard to understand and unlock the value of 'Local energy'. Currently the value is not seen, as there is a lack of visibility on the LV network. If you can't see it, you can't value it, nor monetise it. GBE is working on potential 'product's that can fill this 'Missing middle' and bring forward the value of local energy.

17. Appendices F – Restoration European Hydropower Schemes:

17.1. France EDF Renouveau Program Hydropower 2014

In 2013, a major 10-year rehabilitation program was launched involving more than 230 hydropower units in France including the renovation of the speed governors and excitation systems. The project, funded by the European Investment Bank, also includes an innovative service contract called 'MCO', aimed at maintaining the equipment in good operational conditions and extend its lifetime. This contract comprises the provision of a centralised web-based platform to store all project data, spare parts inventory management, services and support, as well as monitoring material life cycles.

The 93MW Romanche-Gavet project, which was part of the Renouveau Program was completed in 2020. Comprising a new dam and an underground power plant, Romanche-Gavet is replacing six old plants and five old dams. The plant can increase power output by 40% along the same stretch of La Romanche river.

17.2. Demonstration of sustainable hydropower refurbishment (EU Horizon Project - 2023)

Project results are expected to contribute to all of the following expected outcomes:

- Refurbish, upgrade and increase existing hydropower capacity to make it fit for market and digital challenges of the future power system and for supporting increasing shares of variable renewable energy sources.
- Increase technology leadership, competitiveness, and technology export potential of European hydropower industry.
- Enhanced sustainability of refurbished hydropower installations, taking fully into account circular economy, social, economic and environmental (including climate change) aspects in line with the European Green Deal priorities and in particular biodiversity.

17.3. ReHydro Project

The ReHydro project aims to increase the importance of hydropower as a reliable energy source in the EU. As most of the existing hydropower plants were commissioned in the 1960s and 1980s, they no longer meet modern standards of sustainability, digitalisation and flexibility.

The project involves 22 partners from 7 European countries: Each of them brings their own unique expertise to the project.

Over the course of the project, so-called demonstration sites will be upgraded, refurbished or retrofitted with modern technologies to test their impact on the set targets. ReHydro will focus on developing and testing a new turbine design that protects biodiversity, increases taxon richness and improves the suitability of aquatic habitats. This new design will also help to make hydropower plants more fish-friendly, with a focus on the european eel, a highly endangered and migratory species.

17.4. SHERPA Project:

The project brings together seven key partners from across Europe to develop innovative solutions aimed at improving the efficiency and sustainability of hydropower plants.

The project's key technological innovations include:

- Advanced materials and coatings to reduce damage and enhance resistance to cavitation.
- Adaptive rotational speed strategies to adjust turbine speed based on water flow.
- Air injection systems to improve water quality and operational efficiency.
- New runner designs tailored for better performance under E-flow conditions.