Long Duration Electricity Storage: Draft Special Licence Conditions response

Type of feedback - Clarity (C), Workability (W), Reporting (R), Gaming (G), Financiability (F), Incorrect (I), Outside (O)

Perspective - 1 Strongly Disagree, 2 Disagree, 3 Neutral, 4 Agree, 5 Strongly Disagree

Consultation Questions

Q1 Administrative vs ACOD Approach (C,W,F, 4)

a) *Is the distinction between the administrative floor and the ACOD (Actual Cost of Debt) floor clear and workable in practice?*

LDES ACOD approach appears to be equivalent to the precedent for interconnectors. The LDES ACOD repayment priority appears clear and workable, subject to setting of a reasonable Post-Regime Duration Period which is fair across all technologies (see Q10 response).

b) *Are the repayment and priority rules clear and workable where the ACOD approach gives higher support? What would you change, why, and what evidence supports this?*

Scottish Renewables (SR) continues to review this aspect but has no further feedback at this time.

Q2 Market Related Costs and Marginal Cycling Costs (C, G, F 2)

a) *Is the boundary between Market Related Costs, Marginal Cycling Costs, other costs and Excluded Costs clear?*

(1) The definition of Marginal Cycling Costs includes ‘short-run wear and tear’ but excludes ‘long-run degradation’, This is ambiguous as long run degradation is caused by a series of short run wear and tear. These degradation costs could be included in the operational costs and if necessary, as an Income Adjusting Event. Otherwise, they could be included under SC4, clause 8, e) ‘any other costs that the Authority specifies by direction as Market Related Costs for the Relevant LDES Facility’ on a case-by-case basis. If Marginal Cycling Costs are retained for PSH these are most closely associated with running hours rather than ‘throughput’ volumes (e.g. spinning reserve at low load also cause machine wear) and account may also be needed for loss of availability due to additional maintenance.

(2) More generally to ensure a predictable financial outcome for PSH it is critical that all costs associated with the design, construction, operation and decommissioning of the LDES facility can be mapped to a definition which determines their economic treatment. I.e. accounted for in cap and floor levels (e.g. revex, capex, repex, controllable/fixed opex and decomex) vs passed through and accounted for in assessed revenue (e.g. MRC, NCC and IAT). Currently only the latter are formally defined and hence there is the potential for misunderstanding as to how costs are to be treated for the purposes of SC4, SC5, SC7, SC8, SC9 and SC10 in particular. Examples of potential misunderstanding include SC9 referring to "construction costs" as an undefined term and similarly in SC8 "opex" is not defined.

Excluded Costs are reasonably well defined, however limb (j) of the definition - which excludes cost that are not demonstrably economic, efficient and effective - is extremely broad, subjective and potentially consequential as it could result in costs that the project developer was counting on recovery of, either through the floor or assessed revenue calculations, being excluded. Ex post the costs may seem inefficient but it may be difficult to verify what the expectations were ex ante.

The above issues 2 & 3 are likely to be of concern to potential lenders and investors given they create uncertainty as to what costs will be recovered and how the cap and floor will work in practice.

Suggestions:

(1) SR urges Ofgem to consider removing Marginal Cycling Costs from SC1 & SC4 and instead roll them into fixed Opex and/or project-specific other costs.

(2) SR urges Ofgem to consider adding definitions for all categories of cost which are relevant to either setting cap and floor levels or to the calculation of assessed revenue. Consider working level engagement with industry to ensure the final set of definitions provide clarity to lenders, investors, developers and Ofgem as to how all anticipated LDES costs (revex, capex, repex, controllable/fixed opex, decomex, market related, non-controllable etc) will be treated.

(3) SR urges Ofgem to consider including framework/principles for how it will determine whether an element of cost will be considered "demonstrably economic, efficient and effective". Consider developing worked examples to illustrate the same. Ofgem to also consider clarifying the appeal/dispute resolution process should a project developer not agree with an Ofgem determination of Excluded Cost and/or recoverability via assessed revenue.

b) *Are the proposed evidence requirements proportionate and workable? If not, what would you change, why, and what evidence supports this?*

Scottish Renewables (SR) continues to review this aspect but has no further feedback at this time.

Q3 Optimiser Fees cap and related-party controls (C, 2)

a) *Is the drafting clear on what must be reported for optimiser arrangements, including where trading is "in-house"?*

The optimiser fees 'haircut' appears unnecessary, complicated and it will be difficult to set the cap. The issues Ofgem are addressing appear to already be covered by other conditions such as Structured Transactions. We therefore recommend removing this restriction.

Suggestions:

SR urges Ofgem to consider removing the optimiser cap completely.

b) *Are the controls and evidence expectations proportionate across different optimisation models? If not, what would you change, why, and what evidence supports this?*

Scottish Renewables (SR) continues to review this aspect but has no further feedback at this time.

Q4 Gross revenue (C, F, 2)

a) *Is the definition of Gross Revenue clear, including where third parties (including optimisers) receive amounts or settle on a net basis?*

In general, this seems to be a satisfactory definition of gross revenue, reducing the risk of revenue misallocation and cap and floor distortion.

b) *Does the approach avoid double counting and gaps, including for co-located and behind-the-meter set-ups? If not, what would you change, why, and what evidence supports this?*

SR continues to review this aspect, but has no further feedback at this time.

Q5 Post construction adjustments: Cost Overruns (C, W, 2)

a) *Is the approach to assessing outturn costs clear and workable, including evidence requirements?*

It is critical that PSH projects can have reasonable certainty as to the outcome of the PCA process as this will determine whether or not lenders/investors can have confidence in the function of the cap and floor and its ability to provide adequate revenue certainty in the downside, and reasonable return on investment in the upside.

(1) Further to our response to Q2 it is important that the special licence conditions are clear as to which costs fall to be considered under the PCA e.g. what is the definition of "construction costs" and under what circumstances Ofgem may disallow costs as excluded or not being demonstrably economic, efficient and effective.

b) Does the draft strike the right balance between delivery incentives and financeability? If not, what would you change and why?

(2) In addition, as per our response to Q7 regarding Force Majeure, in order to have the right balance between delivery incentives & financeability Force Majeure should be extended to include cost and/or delay events which are outside the control of the licensee, not reasonably to be expected at the site and not recoverable through commercially available project insurance.

(3) Finally, as drafted the special licence conditions appear to contemplate a period of up to 15 months (3 + 12) to elapse between the project developer submitting their proposed PCA terms and Ofgem accepting or determining the PCA outcome. This time period can be further extended by clock stopping whilst any additional information requests are being responded to by the project developer. We are concerned that this may result in the cap and floor assessment for the first relevant year being undertaken based on the preliminary cap and floor which could result in financial distress for the developer if the outturn costs are higher than the p50 used to set the preliminary cap and floor. We therefore propose that these timescales are significantly reduced and/or the cap and floor assessment is based on the developers initial submission until Ofgem has finally determined the PCA.

Suggestions:

1. Please see SR's response to Q2 relating to the clarification of defined terms for all relevant costs and the application of the "demonstrably economic, efficient and effective" test.
2. Please also see SR's response to Q7 relating to the extension of the Force Majeure clause.
3. SR urges Ofgem to consider either reducing its response time in SC7 under paragraphs 13 and 19 respectively from 3 months to 1 month and from 12 months to 3 months, and/or introduce the concept of a provisional PCA based on the developers initial submission which will be used for the purposes of the cap and floor assessment until Ofgem has finally determined the PCA.

Q6 a) Availability target (W, F, G, 1)

a) Clarity, practicality and proportionality: Is the availability measure clear and workable across LDES technologies, and are the proposed thresholds, reporting and evidence requirements proportionate? If not, what would you change and why, including likely consumer impacts, with supporting evidence (for example RAM studies and operational datasets).

(1) The PSH industry is proud of having long-term reliability with high availabilities for decades to come. However, an annual target of 95% with no outage allowance, with the consequence of not achieving being the removal of the floor, is not bankable.

We note that the Interconnector C&F regime uses a Minimum Availability of 80% excluding permitted outages (e.g. force majeure, pre-agreed planned maintenance). This is a more bankable minimum threshold and the exclusion of the planned outages will prevent potential issues with PSH maintenance cycles which could otherwise risk losing their floor support each time they shut down for major maintenance. Also, the IC regime includes incentives to out-perform a project specific reference availability, providing an incentive for projects to maintain the very best availability. Overall, the approach to availability used in the IC regime would be far more appropriate for the LDES C&F.

(2) in SC12 clause 3 you state 'The licensee must maintain the technical capability of the Relevant LDES Facility to at all times. This suggests an obligation for 100% availability which will be impossible. This should be relaxed to make reasonable endeavours.

Suggestions

(1) SR urges Ofgem to consider adopting the Minimum Availability procedure – including the minimum availability target of 80% excluding permitted outages and good availability incentives - used in Window 3 of the Interconnectors C&F.

(2) SR urges Ofgem to consider adjusting SC12 clause 3 to 'The licensee must make reasonable endeavours to maintain the technical capability of the Relevant LDES Facility to at all times…'

Q6 b) Equivalent availability calculation (C, W, 2)

b) The new Balancing Mechanism Parameters for Limited Duration Assets (GC0166) and parameter mapping: After GC0166, should the Equivalent Availability Calculation use the Balancing Mechanism technical parameters each Settlement Period, with any MEL/MIL mapping set out in the RIGs and recorded in the FSPR? If not, what approach should replace this, and why, including any interaction with outage declarations and Exceptional Events?

(1) The equivalent availability calculation is complex and includes ambiguous elements which risks unintended consequences for the network and adds uncertainty risk for investors.

(2) The EAC calculation in (SC12 cl 10) has an either/or element with regards to using import/export capacities – the lesser value being used. As the facility should be able to both import and export at any time (subject to not being at the far ends of its storage capacity) we suggest the average of both export and import availabilities is used in the calculation. For instance for each period both the import capacity with respect to import reference capacity and the export capacity with respect to the export reference capacity are calculated and averaged. (Note as per Q6d, allowance should be made for PSH reference capacity to vary with state-of-charge).

(3) The measurement of the available import/export capacity seems confusing. SC12 Clause 11 applies where an LDES facility is registered for the balancing market however there appears to be an assumption that the whole capacity will either be in the BM or reserved by NESO with no allowance for other un-contracted capacity. Clause 12 however allows for a more pragmatic approach to be agreed on a project specific basis which would be simpler for all project.

(4) It is unclear what the purpose of the Energy Based Cross Check (SC12 clause 17) is as the role of LDES is not necessarily related to actual running hours but may be to do with other services such as inertia and back-up availability so this could be a misleading measure. In addition, the reference number of hours to determine the reference energy capability is not clearly defined and appears subjective.

Suggestions

(1) SR urges Ofgem to consider reviewing the availability criteria and methods of demonstration and provide worked examples to clarify how this will work in practice for each technology.

(2) SR urges Ofgem to consider adjusting the EAC calculation in SC12 clause 10 to account for both import and export capability in each time period, including allowance for PSH variations in reference capacities related to state-of-charge (as per Q6d).

(3) SR urges Ofgem to consider reviewing SC12 clause 11 & 12 with regards to implied restrictions in modes of operation with a view to simplifying to improve clarity.

(4) SR urges Ofgem to consider removing the Energy Based Cross check in SC cl 17-22 from the licence.

Q6 c) Reference capacity (C, W, 3)

c) Reference Capacity and directional asymmetry: For the Equivalent Availability Calculation, should Reference Capacity be the lower of proven maximum import and export capability at the Boundary Point? If yes, does this manage directional asymmetry proportionately, and if no, what alternative should apply? Please explain how the proven maxima should be evidenced (for example commissioning and periodic test results).

As per Q6b, the relevant reference capacity for both import and export should be used with the measured import/export capacities as per.

Suggestion

SR urges Ofgem to consider including both import and export reference capacities on the FSPR for use in the EAC calculation (ref Q6b), including for PSH any necessary relationship to state-of-charge (as per Q6d).

Q6 d) Variation with state of charge (C, W, 2)

d) Reference Capacity varying with State of Charge: Should any technologies be allowed to use a reference capacity that varies with State of Charge (for example closed-loop PSH)? If yes, why is this in consumers' interests, and how could it be implemented in a clear and auditable way?

Some PSH projects will not be able to maintain the constant export capacity (turbine operation) across their full range of state-of-charge and none will be able to maintain constant import capacity (during pumping). This is a fixed specific characteristic of the facility and could be set in the FSPR at the time of Cap & Floor award, along with the overall average export/import capacities. This could then be included as a parameter to determine the reference capacity for the EAC calculation for each time period.

Suggestion

SR urges Ofgem to amend the Equivalent Availability calculation in SC12, clause 10, to allow for a variable import and export reference capacity with state-of-charge for PSH projects.

Q6 e) Energy capability degradation (C, W, G, 2)

e) Energy capability degradation and floor eligibility: Are the Minimum Duration obligation and Schedule B periodic performance testing (including breach and remedial provisions) sufficient and proportionate to manage energy capability degradation? If not, should endurance test outcomes affect floor eligibility, and if so, how?

SR understands that notwithstanding "Permitted Degradation" that schemes must deliver Minimum Duration and Rated Export Capacity as per their FSPR and these parameters are locked at Cap and Floor award and not amendable (Schedule B, Part B, clause 12). However drafting of the Permitted Degradation clauses is confusing and clarity is needed to reinforce the absolute requirements that projects must always deliver Minimum Duration and Rated Export Capacity

We suggest that the references to Permitted Degradation in Sch B, section B, clause 9 are removed.

Q6 f) Exceptional Events (C, G, 4)

f) Exceptional Events and outage coding: Are the definitions and processes for Exceptional Events, outage categorisation and boundary metering issues clear and robust enough to ensure consistent availability calculations across technologies? If not, what would you change, and what safeguards would prevent misclassification or under-reporting?

SR continues to review this aspect, but has no further feedback at this time.

Q7 Force Majeure and Exceptional Event (W, F, 1)

Are the definitions and process clear enough to apply consistently, and is the evidence burden workable and targeted at the right risks? If not, what would you change, why, and what evidence supports this?

The LDES C&F Force Majeure definition is unusually narrow. It does not explicitly make allowance for events outside the control of the licensee relating to weather/ground/environment which are not reasonably to be expected at the site. It also does not allow for grid connection delays as well as industrial action which are outside licensee's control. The proposed definition is one of the more restrictive we have encountered and is likely to be of concern to potential lenders, investors and developers.

While it appears to mirror that used for interconnectors, that provision also included a 'Reasonable Delay' clause where Ofgem may agree date changes for events outside the reasonable control of the licensee

(and not covered by the FM clause). However the addition of Reasonable Delay may not be sufficient for the risks associated with a PSH project as it allows only for delay and not costs.

(1) SR consider that the Force Majeure clause should be extended to events such as grid connection delay; strike, lockout and other industrial disturbance; weather, environmental and ground conditions which are outside the licensees' control and are not reasonably to be expected at the site. The latter are particularly important for PSH projects, which are highly ground-dependent and exposed to low-probability, high-impact subsurface risks. They are also typically located at high altitudes in the Scottish Highlands making them more exposed to severe weather than projects elsewhere. These are not recoverable through commercially available project insurance and so leave the developer with potentially uninvestible risks.

(2) Items on the risk register are excluded from FM which could dissuade developers from considering all of the risks or create strategic incentives for developers to exclude events from it, particularly if merely identifying a risk would prevent it from qualifying as FM. In addition, the items on the register can have their cost element allowed within the P90 cost estimate, however there is no mechanism for programme impacts of these risk items to be taken into account if they cause a delay which exceed the imposed 2 year backstop date. Therefore, adjustment to the dates must also be allowed for items which are on the risk register.

(3) SR also note the requirements for licensee to advise FM within 10 days (preferably before any associated spend) which is quite extreme. However, the authority then has 6 months to make a determination and this can still be changed during the PCR. This imbalance in requirements will put the authority out of step in their risk management. They should have the same obligations to respond so that the risks can be managed jointly.

(4) Finally, while SR understand the intention to remain technology neutral, the delay risks associated with the construction of a large PSH project taking many years cannot be compared with technologies which have shorter construction periods. For instance, for a 2-year planned construction the 2-year backstop allows for a 100% programme delay, whereas for a project taking 6 years to construct it is only a 33% programme delay allowance. This is not a fair approach and puts a disproportionate level of risk on the larger PSH projects which longer construction periods.

Suggestion

> (1) SR urge Ofgem to consider expanding Force Majeure to include cost and/or delay for events which are outside the control of the licensee, not reasonably to be expected at the site - and not recoverable through commercially available project insurance - relating to grid connection delays, industrial action; weather, environment and ground conditions.
>
> (2) SR urge Ofgem to consider removing the exclusion in SC1 FM definition for FM items being on the risks register and also permit delays associated with non-FM riskregister items which are beyond the backstop date.
>
> (3) SR urge Ofgem to consider extending the licensee obligation to advise FM to 28 days and reducing the authorities time to make a determination to 3 months and make it binding.
>
> (4) SR would support a discussion between Ofgem, the /British Hydropower Association and PSH experts, to developer a fair and investible allocation of risk for projects with longer build durations.

Q8 Backstop date and the Backstop Delay Charge regime (F,1)

Is the backstop and delay consequence package clear and proportionate, and does it create the right incentives without introducing avoidable financeability risk? If not, what would you change and why?

The Backstop Delay Charge (SC6 Part F / SC9.63) as drafted presents material investibility concerns for PSH projects. There are 2 key issues which need to be addressed together:

a) Charge mechanics are disproportionate providing binary cliff-edges independent of overrun scale. The dual binary trigger (see SC9.63) means that BDC applies only if the project is both past Backstop and above P50. This means that £1 above P50 = full BDC, £1 below zero BDC regardless of how late. Backstop date is similarly binary so one day and twelve months late in year 1 both incur 20% floor reduction. Even with improved treatment of delay risks this presents a serious risk to investors.

b) A distribution lock-up is created by BDC which is punitive and could become permanent. This is caused because SC6.55 prohibits all equity distributions while BDC Balance outstanding, with no Ofgem release gate. The issue is caused because repayment requires above-floor surplus (SC6.48), In below-floor years the balance does not reduce and the lock persists. Post-regime the mechanism perpetuates: SC2.3(c) keeps the obligation alive; SC6.48 needs Floor Level in force (SC2.2) to calculate repayment; post-regime there is no Floor Level, SAR is zero, repayment cannot occur so lock is apparently permanent. An Internal inconsistency within SC6 Part F: para 51 protects floor-level revenue from BDC repayment; para 55 bans all distributions.

The interconnector C&F window 3 uses regime duration reduction such that late delivery reduces the regulated period day-for-day once delay passes Backstop. This provides the same consumer protection (late = less regime support) but it would solve both above problems as there is no cliff edge in support improving investor certainty and no or requirement tracked balances and the unintended lock-up.

Suggestion:

> SR urges Ofgem to consider resolving the issues of both the double cliff edge and distribution lock by adopting the Backstop delay regime used in the interconnector C&F Window 3.

Q9 Revocation events (W, F, 3)

Is the proposed revocation approach clear and predictable, and does it provide an appropriate backstop for non-delivery without creating unnecessary investor risk? If not, what would you change and why?

Subject to the Longstop term being sufficient - e.g. 5 years after Backstop - then the proposed approach appears clear and predictable, providing investment certainty. However, there should be a mechanisms for the long stop date to be adjusted in line with the Target and Backstop dates in the event of delay events.

Suggestion:

> SR urges Ofgem to consider including adjustments to the long stop dates in line with those agreed for target and backstop dates in the event of agreed delay events.

Q10 Post regime treatment (C, F, 2)

Are the post-regime arrangements clear and predictable, including what continues after the regime ends? If not, what would you change and why?

The post-regime arrangements appear to reflect the interconnector approach, requiring any outstanding payments e.g. floor, ACOD differential, BDC to be made before equity distributions.

SC1 Clawback is defined as being timebound and proportionate. The Post-Regime Duration Period definition suggests that its duration will be at the discretion of the authority recorded in the FSPR – though it is not shown as an item in the draft. However, SC2 suggests that it will continue indefinitely until the balance is zero. This lack of clarity regarding the obligations at the end of the project creates investment uncertainty, particularly for projects where the life of the asset may align with the life of the scheme. A fair technology neutral time-limited approach is required to provide investor confidence.

Suggestion:

> SR urges Ofgem to consider including Post-Regime Duration Period in FSPR with a time limit suggested as 5 years. In addition, clarity to be provided for situation where the project is decommissioned before the end of the Post-Regime Duration Period.

Q11 Financial resilience (F, 4)

Does the proposed financial-resilience package strike the right balance between consumer protection and bankability? If not, what would you change and why?

The proposed package of measures to ensure financial resilience appears appropriate. Approaches for addressing ACOD differential payments should be defined in individual project licences to provide investment certainty.

SR continues to review this aspect, but has no further feedback at this time.

Q12 Structured transactions and revenue maximisation (C, W, I, G, 2)

Are the restrictions on structured transactions and the revenue-maximisation duties clear and workable, and are the monitoring, evidence and enforcement tools proportionate? If not, what would you change, why, and what evidence supports this?

(1) The term 'revenue' in Revenue Maximisation is misleading as it is not a defined term within the context of the Special Licence Conditions. The Cap & Floor calculations are based on the defined term Gross Margin – we believe that it is this which the authority would wish the licensee to maximise.

(2) SR are concerned that it will be very difficult to establish for a storage asset. Ex-post the operation may seem inefficient but there is no way to verify what the expectations of price changes were ex-ante. Especially for an asset that is capable of importing and exporting and has a limited capacity. The licensee may operate sub-optimally based on a predicted future which does not materialise.

(3) Finally, the Pricetaker obligation (SC18) should be removed and managed outside the LDES C&F regime along with the other restrictive operational proposals covered in Q17-23.

Suggestions:

> (1) SR urges Ofgem to consider changing the term Revenue Maximisation to Gross Margin Maximisation in SC18 and elsewhere.
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> (2) SR urges Ofgem to consider how the maximisation of gross margin can be practically established.
>
> (3) SR urges Ofgem to consider removing the pricetaker obligation.

Q13 Co-location, behind the meter & energy losses (G, 3)

a) *Is Schedule C clear about the rules for co-located and behind-the-meter arrangements, including how energy flows are metered, how they are attributed between the LDES and other assets, and how any energy losses are treated?*

b) *Are the associated evidence and assurance requirements (to demonstrate compliance with these rules) proportionate? If anything is unclear or onerous, what would you change, why, and what evidence supports this?*

SR continues to review this aspect, but has no further feedback at this time.

Q14 Model governance and the FSPR (C, W, 4)

Do the proposed governance arrangements for the Ofgem model suite (LDES CFFM1 and CFFM2) and the FacilitySpecific Parameters Register provide enough certainty and predictability, while allowing timely updates without reopening the licence? If not, what changes would you propose and why?

This appears to reflect other Ofgem precedents and experience of model governance. However we have concerns about the authority's power to change the terms of the FSPR where the licensee only has the ability to make representation with no mention of dispute resolution process.

Suggestion

> SR urges Ofgem to consider a more balanced approach and address processes for dispute resolution more generally.

Q15 Transmission Network Use of System (TNUoS) charges (F, 1)

a) *Should TNUoS charges be borne by the licensee or passed through, in full or in part, as a non-controllable cost? If some pass-through is appropriate, what triggers and safeguards should apply to preserve locational signals?*

b) *Should any pass-through be smoothed through an allowance with later true-ups? Please provide evidence, data or modelling where available*

The licence is drafted to allow full TNUoS pass through, but the consultation text suggests that Ofgem are considering a partial pass through instead. This may reflect views on potential future TNUoS reforms. We suggest that full TNUoS pass through be retained to provide investment certainty. If changes are proposed, then this will add additional risk, and will undermine proposed floor and cap WACC parameters. In addition, TNUoS is very volatile so costs should not be smoothed but passed directly through.

Suggestion

SR urges Ofgem to retain the full unsmoothed TNUoS costs pass-through proposed in the draft licence conditions.

Q16 Proving periods and performance test protocol (C, W, 2)

Do you think the proposed proving windows, 10 days for BESS and 30 days for PSH, LAES and CAES, together with the ongoing testing requirements in Schedule B are clear, proportionate and enforceable? If not, what would you change and what evidence supports your proposal?

(1) SR support the need for proving tests periods – however see no reason why this should be different durations for different technologies. Both the proving period and the full cycle performance tests should occur after Full Commissioning and so do not disadvantage technologies with longer storage durations (or longer proving periods. Doing them prior to Full Commissioning at the end of the lengthy construction programme puts undue pressure on commissioning teams at a time of particular health and safety risk. Moving them post Full Commissioning relieves this time pressure while still providing protection to the consumer that protection of the floor can be later rescinded.

(2) Tests required for Full Commissioning should be reduced to the completion of all commissioning tests required for safe full operation as well as proving MIL and MEL capability (taking into account the state-of-charge for PSH) and suitable declaration that the full storage capacity is available, and the station can be put into full operation.

(3) The performance test requirement should be tech/size specific. For larger projects, full cycle performance tests will not be practical due to the management of the large power volume durations on the network. For PSH it should be sufficient to prove stable full load operation in both directions at various storage levels. Other technologies may need different criteria to demonstrate this capability. The timing of the tests will need to be managed closely with the TNO and within a suitable timeframe. If the tests are not successful within the time frame then penalties can be applied retrospectively.

(4) Three yearly compliance tests for BESS appears appropriate given the high risk of degradation but this risk is lower for long-life PSH assets. Ten-yearly compliance test is more appropriate for PSH assets.

Suggestions:

(1) SR urges Ofgem to consider including in Sch C that proving periods of 30 days after Full Commissioning for all technologies are to be achieved.

(2) SR urges Ofgem to consider reducing the scope of commissioning tests in Sch C to the proving maximum import and export capability and a suitable declaration of the full storage capacity being available, and the station can be safely put into full operation.

(3) SR urges Ofgem to consider changing the Performance tests requirement in Sch C such that it is carried out within 1 year AFTER Full Commissioning and includes the demonstration of the capability for stable full load operation for up to the site's full storage duration at all storage levels.

(4) SR urges Ofgem to consider changing Sch C clause 3b such that the licensee for PSH projects shall conduct a Periodic Performance Test at least once every ten (10) years during the Operational Period.

Q17 Overview (priority of Q18-23) (G, F. O, 1)

Across the areas in Section 4, what should Ofgem prioritise as we finalise Window 1, and what evidence should we use to decide what belongs in the licence, in RIGs, or in future decisions? Please also tell us if you think any of these areas do not need further work, and why?

SR is concerned about the additional services & restrictions which have been added to the licence condition which may have a number of unintended consequences which prevent the maximisation of benefits the regime was designed to achieve. We feel strongly that the market concerns would be best managed via new or existing market incentives and regulations. Therefore the priority across the section 4 items is to avoid the operation restrictions suggested Q18, 20, 22 & 23 from within the LDES C&F licence.

The primary concerns are:

- The purpose of the regime is to ensure that the necessary LDES capability is available on the market when required.
- In providing the regime Ofgem have an obligation to maximise the benefits of the LDES projects supported by the consumer and as such Ofgem should not restrict their potential system benefits nor increase the consumer risk of floor payments.
- Any restrictions could reduce gross margins which strikes at the heart of a support regime which is based on the licensees obligation to maximise gross margin.
- The LDES assets' Traders may over-price the risk of a license breach, in order to stay safe, which will lead to significantly sub-optimal asset performance.
- Issues should be fixed with market incentives which impact all players in the market rather than restrictions – carrot rather than stick.
- This significant change to terms of the scheme could invalidate the business cases already submitted.

Q18 Supply and availability during system stress (G, F. O, 1)

In a system stress event, should LDES operators have any additional, explicit licence expectations beyond following NESO instructions? If yes, what should they cover (for example coordination, information sharing, or performance expectations) and how can they be framed to avoid conflict with existing arrangements such as G18-Capacity-Market-Stress-Event-Guide_v10.0.pdf. If no, please explain why.

SR welcomes future engagement on this topic, however this issue is not specific to LDES C&F projects and so should be resolved in the wider market. LDES projects should be available to provide system service if required - we suggest this should be a paid via a system service contract with NESO.

Q19 Cybersecurity and operational technology resilience (O, 4)

DESNZ and Ofgem will jointly consult on wider cyber regulation which we encourage stakeholders to engage with. Beyond that consultation, we would be interested in understanding your views on proportionate cybersecurity approaches for LDES.

Again, SR welcomes future engagement on this important topic, however this issue is not specific to LDES C&F projects and so should be managed by wider industry regulation. We agree that a proportionate light touch protection approach be adopted for supply chain, delivery, and operational stages. It should align with NCSC Cyber Assessment Framework, the Cyber Security and Resilience Bill, and UK National Security Procurement requirements.

Q20 Algorithmic optimisation governance and execution quality (G, F. O, 1)

Should Ofgem introduce a proportionate, outcomes-based standard for optimisation (including algorithmic optimisation), and if so, what is the minimum evidence we should ask for to assess execution quality without requiring disclosure of commercially sensitive strategy?

This is not a specific LDES C&F licence issue so it should be resolved more widely. However, SR supports the use of an outcome-based approach as it appears difficult to specify ex-ante governance arrangements.

Q21 Hedging governance (G, 3)

What level of disclosure about operational hedging (including any intra-group hedges) is proportionate to support auditability and consumer protection, while avoiding requirements that would reveal trading strategy or intellectual property?

The current licence drafting requires information to be provided annually on hedging policy but not on hedging trades and costs. SR considers that Ofgem should also have visibility of hedging trades and costs to reduce the risk of cap and floor distortion.

Q22 Repetitive Re-trading (G, F. O, 1)

How material is RRT for consumers and LDES cap and floor outcomes? Please provide evidence. If it is material, what (if anything) should Ofgem do within the LDES regime (for example monitoring, reporting, or threshold tests) to protect consumers without restricting legitimate revenue maximisation? If no action is needed, please explain why (for example due to wider market reforms) and provide evidence

RRT is a market-wide behaviour affecting all storage technologies, though we expect it is more prevalent for short-duration storage where export physical notifications can be shifted into adjacent settlement periods. Longer-duration storage typically reschedules output over much longer time horizons, making any re-trading less directly linked to the original constraint. As such, LDES-specific measures would not be fair or proportionate and would risk discrimination. If intervention is required, it should apply consistently across the storage sector through a single, coherent regulatory framework,

SR therefore agrees with Ofgem that RRT is best addressed through market-wide reforms. National Pricing reforms directly target the locational and temporal signals driving this behaviour, while NESO's "Storage behind constraints" review is examining the drivers and system impacts of RRT, including whole-system analysis to assess its true materiality. These initiatives are better placed to address RRT coherently and consistently across the market.

Q23 Operating as LDES (G, F. O, 1)

Do you think the draft licence and reporting framework should do more to ensure that cap and floor supported LDES continues to deliver long duration capability over its lifetime? Please address the four areas set out in the CfI.

i) Minimum safeguards – SR does not agree that the safeguards 1 (operate within the approved long-duration envelope), 3 (annual monitoring and reporting) or 4 (general duty to operate as long-duration) should be applied. Any issues should be managed via wider market incentives instead. However, the safeguard 2 (through-life performance checks) are reasonable to ensure the facility maintains it capabilities for use in the market if managed pragmatically as per our response to Q16.

ii) Additional safeguards - while SR welcomes the intent to ensure genuine LDES is deployed, we do not consider that Option A (a hard LDES duty) or Option B (limit short cycling) will work as they will limit the operational freedom (and revenue potential) of LDES assets. We consider that Option C (LDES availability enhancements) has the potential to secure LDES behaviour provided there is some financial incentivisation and support further investigation. We suggest that this could be achieved through long term commercial contracts for LDES system services with NESO outside the LDES C&DF licence conditions.

iii) LDES to 'operate as LDES' should therefore not be a hard duty at all but best endeavours.

iv) The purpose of the scheme is to ensure that the necessary LDES capability is there such that it is available on the market when required. Greatest benefit to the consumer will be for the LDES projects to perform well, avoid operation below the floor and operate above the cap. If LDES gap is found this should be fixed in the market, not by restrictions which will inevitably reduce revenues.

Suggestion:

SR urges Ofgem to consider removing the restriction in SC12 Clause 43 requiring LDES to operate as LDES. Instead Ofgem to consider further working level engagement with industry to further

clarify the issue they are seeking to address through "Operation as LDES" special conditions and to work jointly to develop arrangements that balance any concerns regarding availability to operate as LDES, with the desire to minimise the cost to the consumer of any price support provided via the floor mechanism by ensuring LDES facilities can access multiple sources of revenue.

END