A specialist energy consultancy

DNO Business Case Review

Resilience as a Service

SSEN

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Executive Summary

Scottish & Southern Electricity Networks (SSEN) has commissioned TNEI Services (TNEI) to review the business case for a novel approach to improving the reliability of service to customers in rural and remote areas using the RaaS - Resilience as a Service - concept currently being investigated through an innovation project[1] funded through Ofgem's Network Innovation Competition (NIC).

Within the project, SSEN and its partners E.ON and Costain are exploring the prospect of using third-party distributed energy resources - incorporating battery energy storage - to cost effectively improve resilience for areas of network that currently experience atypically high levels of interruption. The scope of our review within this extends to a group of topics related to the business case for a DNO to commission RaaS providers, namely modelling methods for valuation of the service, potential payment mechanisms, and the possible role of forecasting.

As part of the original submission for NIC funding, an initial business case and cost benefit analysis (CBA) were created to indicate the potential benefits of this approach. That work considered the case for RaaS over the very long-term, and across the entirety of Great Britain. TNEI originally supported SSEN in the preparation of this CBA and business case.

With the project now developing the detail of the concept, SSEN also require an enduring methodology for evaluating the business case for commissioning RaaS to support any specific substation within their network.

SSEN has therefore appointed TNEI to revisit and refine the business case, and to develop approaches for assessing the application of RaaS at individual substations, including mechanisms for valuing the service and determining appropriate payment structures.

Cross-cutting observations on the business case

It is worth noting the extent to which all the aspects of the RaaS business case interact with each other and also with the dynamics of wider flexibility markets. There is clear benefit to be realised for customers by reducing interruptions, but the extent of the net benefit is heavily dependent on the payment necessary to secure the service, driven partially by the opportunity cost[2] for the battery of not being able to provide other services. A well designed RaaS service can play some part in reducing these costs, mainly by using skilful forecasts and a payment structure that encourages participation without the risk of excessive payments. However, the designs of the other service markets in which RaaS Service Providers (RSPs) will be participating could be just as important, and a silo mentality when designing and operating those markets is likely to have a significant detrimental impact on the economic viability of RaaS, and indeed other flexibility services use cases.

Another common theme to many aspects of this review is the nature of the marginal benefit of increases in the required service level. For example, for many demonstration sites it has been shown that the marginal benefit of increasing the service duration decreases. In contrast the marginal benefit of increasing the reliability of the service is expected to be constant (in expected value terms). This is

[1] https://project-raas.co.uk

[2] It should be noted that by discussing the fundamental economic concept of opportunity cost here, we are not suggesting that the presence of RaaS among a suite of flexibility services primarily represents lost opportunity for a battery owner/ operator. Rather, the addition of RaaS would almost certainly bring a net benefit to them – the economic analysis simply claims that the battery operator would balance these services to obtain maximum benefit.

important as the marginal cost and/or opportunity cost of providing the service could easily be increasing, and possibly non-linear. This could mean that the optimal level of RaaS for many locations is far below the year-round six-hour capability that was envisaged at the start of the project. Essentially, in the absence of a cost-effective network reinforcement option, even small improvements in resilience could be beneficial.

In general, it is important to bear in mind that the maximum net financial benefit from RaaS will be created by contractual agreements which maximise the difference between the benefit created by the service, and the cost of providing the service. Our valuation suggests that increased levels of service may be associated with diminishing marginal benefit. Alongside this, it is possible to imagine that these might be associated with higher marginal costs. In this case, the financially optimum level of service may be quite modest.

Valuing the RaaS service

Section 3 of this report describes and demonstrates a methodology for determining the value of RaaS, based on expected reductions in the financial impact of interruptions. This method is based on a statistical simulation of interruptions and relies on data about historic interruptions and substation demands, and assumptions about how interruptions drive costs. Example outputs are shown below.

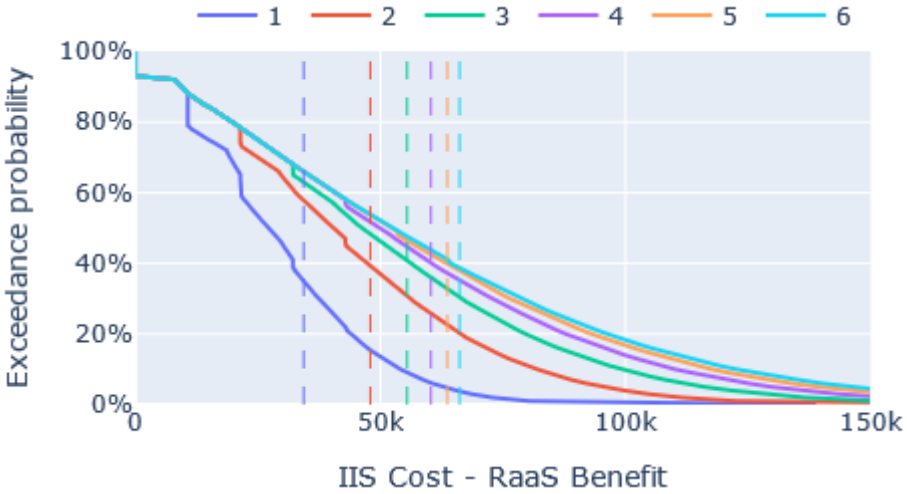

Figure 1: Example of modelled Interruption Incentive Scheme benefit of RaaS

This figure shows the expected long-run level of benefit associated with different fixed durations of RaaS service for one substation, as well as the probability of that level of benefit being achieved within any specific year. Similar results have been obtained for a set of around 20 substations. The method also produces results in terms of the Value of Lost Load, as quantified within a recent innovation project completed by ENWL.

While the method appears to work well, enhancement of inputs, wider scrutiny of assumptions, and further development of the associated process should be considered, if possible, before formally adopting this approach as part of a formal valuation for RaaS services. In particular, the mathematical representation of the duration and frequency of interruptions could be refined further, potentially to incorporate more data, subject matter expertise, and information about different types of

interruption experienced, including transmission outages[3]. When looking at the value of the service in the long run, it might also be necessary to account for factors like increasing frequency and severity of extreme weather events associated with climate change or degradation of network infrastructure, both of which might lead to greater numbers of and/or durations of interruption.

The demonstration of the proposed method also suggests that quite different service values could be justified if valued using IIS incentives costs compared to underlying estimates of VoLL. It is likely that IIS costs underestimate the true VoLL, particularly for interruptions that are unusually frequent or last for a long time. However, the benefit of using IIS costs is that it is clearly justified under the existing DNO regulatory mechanisms, whereas VoLL estimates are somewhat more subjective (even with the recent research projects from ENWL). However, it is worth noting that there is support within P2/7 and EREP130 for DNOs to value services using other estimates of VoLL.

It is important to bear in mind that even a measure like VoLL may not fully capture the costs or benefits associated with interruptions. For example, there may be a reputational cost associated with high levels of interruption and reducing this would provide benefit. Valuing this would likely prove to be very difficult.

One other observation about the demonstration of the methodology is that, in many cases, the marginal benefit of increasing the service duration beyond an hour or two is not very high, particularly when valuing based on IIS. DNOs should therefore consider retaining some flexibility when tendering for RaaS, perhaps inviting bids for a range of different service durations and then evaluating the costs of each service against the benefit in order to determine the best course of action (i.e., most cost-effective scheme for a given site).

The benefit of RaaS

The report considers the implications of the proposed valuation methodology on the GB-level business case for the RaaS project, considering sensitivities with different service durations, and different levels of replicability across the country. For example, the figure below shows how many of the 24 sites assessed have gross benefits that exceed different thresholds, with different durations of service.

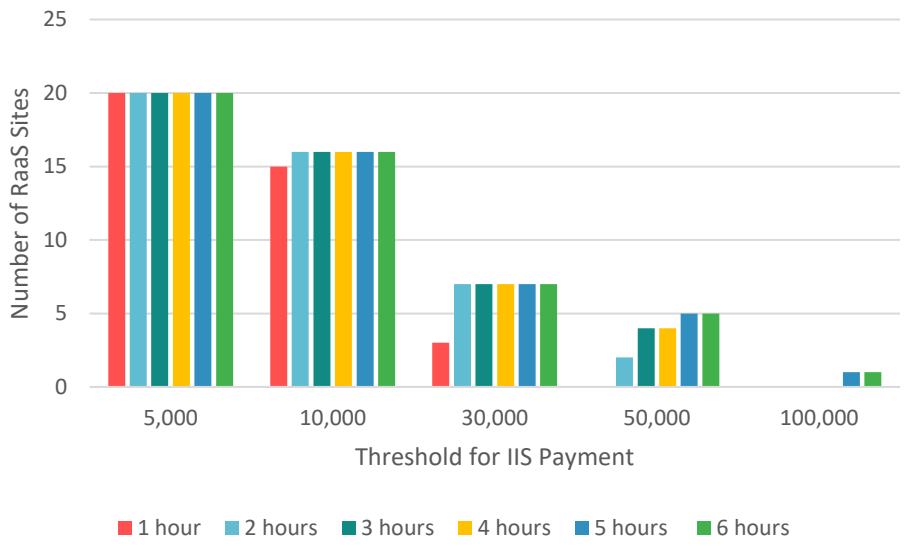

Figure 2: Number of assessed SHEPD sites where IIS benefits exceed threshold

[3] Faults occurring on the transmission network would be addressed by the TO, however a RaaS service would still benefit customers within the RaaS area of the distribution network.

One observation on the valuation methodology is that, if using IIS as the basis of valuing the service, then it is possible that a year-round RaaS service may be cost-effective on a smaller number of sites than initially considered within the NIC CBA submission to Ofgem. However, even if RaaS only proved to be viable on the ten sites which, using the assessment methodology applied for the NIC submission[4], have the highest overall level of benefit, this would still result in an overall GB level net benefit of £26m. This is less than the figure included in the submission to Ofgem, but even in this very pessimistic case, the benefit is still greater than the total funding required for the project. Further, the number of opportunities may increase as costs of battery storage decrease, or as additional applications for RaaS emerge, such as those presented in the RaaS 'Investigation into the Wider Potential of RaaS' report[5], resulting in economies of scale across the supply chain.

However, it is also important to note that the assessment of the GB-level business case would also require an update to the assumptions regarding the fee for a RaaS service. At the time of writing this report, this is still being assessed through work undertaken for project partner E.ON, and it is understood that the DNO business case and RaaS Service Provider business case will be drawn together by the project team following completion of this report. In addition, another key input to the GB-level business case is an estimate of the suitability of this concept for sites across the country. This was estimated within the submission to Ofgem, but a more detailed assessment of the number of possible RaaS sites across other DNO licence area would also add insight here.

This additional information could be assessed together with the valuation methodology described in this report to provide a further refined view of the potential GB-level benefits. To this end, it can be noted that whether RaaS is viable for a location depends on (i) the benefit that the service creates by reducing interruptions, (ii) the cost and opportunity cost of a battery providing that service, and (iii) at what level of service duration and/or reliability does the benefit outweigh the cost, noting that both costs and benefits will change with the definition of the service. Whilst it may be outside the current scope of the RaaS project, this assessment could be undertaken where:

- Historic data on both interruption frequency and duration, as well as historic demands, could be sourced for a much wider group of substations, including those outside of SSEN's networks.
- Service costs could be determined for each of these substations, based on the analysis completed by the RaaS project team.

Payment for RaaS

Section 4 provides a set of versatile building blocks for designing an optimal (or near optimal) payment structure for RaaS. This includes a set of principles which should guide the design of a payment structure, as well as a wide range of components that could be used within that structure, including fixed payments, availability payments based on state of charge, and utilisation payments & penalties that depend on actual interruption costs, as shown in Figure 3.

[4] The NIC submission methodology evaluated benefits based on a comparison against conventional reinforcement, and against the use of DNO owned energy resources that are only used for resilience (with no revenue stacking capability - the CBA did not incorporate assessment of the financial value of interruptions (i.e., CIs/CMLs, or VoLL).

[5] RaaS 'Investigation into the Wider Potential of RaaS' report (C6.1), Costain, August 2021, https://project-raas.co.uk

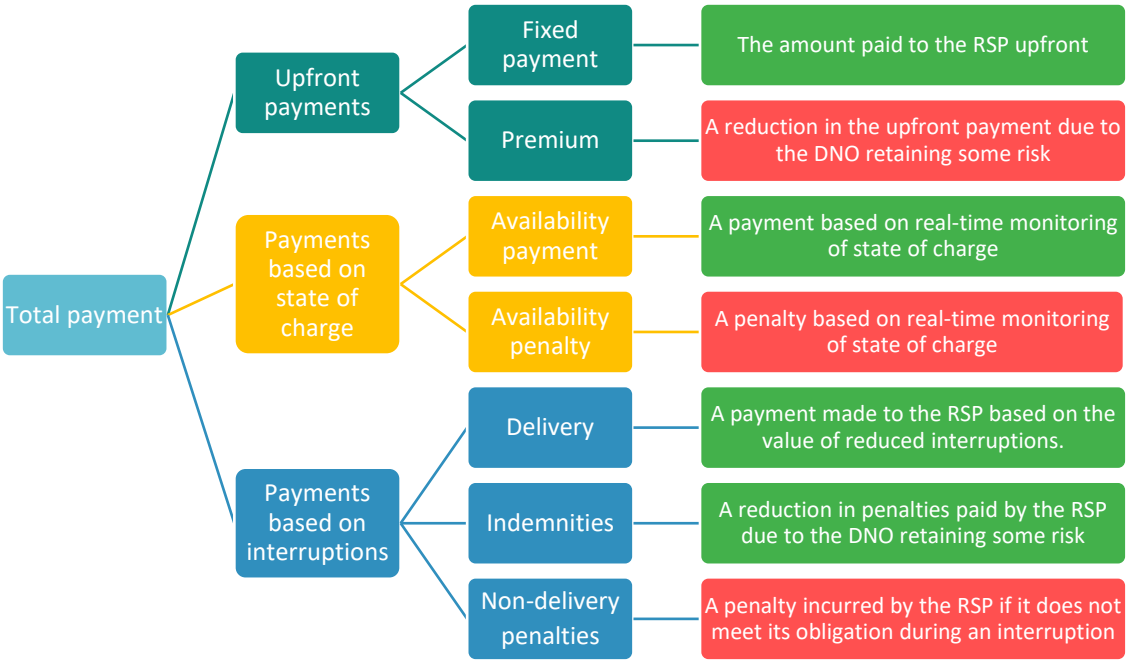

Figure 3: Structure of possible payment components

These building blocks are very flexible and may even allow a wider set of possible contractual arrangements than SSEN and the RaaS project team are currently considering. For example, these payments structures could work for both contractual arrangements that (i) mandate certain levels of service from an RSP that must be fulfilled, or (ii) incentivise a high quality of service while still leaving this up to the discretion of the RSP. The rationale of the latter approach is the same as the rationale which might favour lower duration services: if the marginal benefit of a highly reliable service is less than the marginal cost of an RSP providing that level of reliability (compared to being slightly less reliable), then a DNO may be better placed accepting the lower level of reliability. This could particularly be the case if an RSP wants to provide other services that need to be available/'armed' very frequently, but which are dispatched very rarely, in which case battery capacity may be offered on standby to provide a number of services at the same time, and only be unavailable for RaaS on the rare occasions that another service has required the battery to discharge.

In principle, there are many different payment structures that could satisfy the guiding principles set out in Section 4. We believe that one sensible and theoretically justified approach would be to seek an optimal structure, defined as the one which maximises the expected reward for the RSP – possibly with an additional penalty function to reflect the stability of payments, conditional on the DNO not expecting to be at an overall loss. The rationale here is that the solution that maximises RSP reward is also likely to maximise the interest from flexibility market participants to also offer (the competing service of) RaaS. However, mathematically determining which structure is optimal has not been possible within the scope of this report. This is largely due to the difficulty in defining some of the important probabilistic relationships that would be important for such a mathematical solution, such as the effect that payment levels may have on the behaviour of the RSP and its battery's state of charge.

Nevertheless, the report describes some examples of how these building blocks could be combined and provides some commentary on their suitability. In general, it is anticipated that RSPs will prefer structures which lead to more stable revenue streams, which may reduce service costs by reducing financing costs due to higher certainty of revenue streams. SSEN and the RaaS project team are

encouraged to explore these building blocks further to find a structure that feels appropriate, including through the planned stakeholder and supply chain engagement activities over the course of the operational trial period. Over time, further analysis and experience from the procurement and implementation of RaaS will also provide more certainty on how different payment mechanisms work in practice.

The role of forecasts

Section 5 provides a short discussion of the role of forecasts within RaaS. Forecasts are crucial for the effective operation of RaaS, particularly for determining the necessary state of charge of a battery ahead of time.

When considering the full breadth of possibilities for the operation of a RaaS scheme, there are several viable options for (i) the type of demand forecast to be produced, (ii) who is responsible for producing them, (iii) how these forecasts are used. Each of these options has its own strengths and weaknesses, and there are trade-offs to be considered such as the appropriateness of the forecast vs the cost and effort of producing it. The ultimate choice of forecasting approach, in the wider picture, is likely to depend on the requirements and capabilities of potential RSPs as well as DNOs. However, we understand that the project is, at the time of finalising this report, working with the principle that the fundamental service requirement is defined in terms of MWh available for RaaS, with the appropriate level being forecasted by the DNO.

Another possible role for forecasting would be the prediction of periods where there is a heightened risk of interruptions. There is some reason to think this might be possible, with extreme weather (such as lightning and high windspeeds) being a relatively common cause of interruptions. However, there are still many types of interruption which would be very difficult to predict dynamically. This may be another example where the marginal benefit of protecting against all interruptions is difficult to justify when considering the marginal cost of the service, and it is worthwhile (both for customers and DNOs overall) to use RaaS to prevent a comparatively small proportion of interruptions – say 20% to 50% – on the basis that this leads to a much more significant reduction in the RSP's opportunity costs, requiring a much lower proportion of income from RaaS.

Opportunities for further research and analysis

In Section 6.5, we describe some opportunities for further research and analysis that would help to further refine the business case. This includes:

- Further enhancement of the approach taken to modelling frequencies and durations of interruptions;
- Applying the valuation methodology to different future energy scenarios, to consider the possible value of the service as the energy transition progresses;
- Modelling, probably through simulation, the relationship between different payment structures and the battery's state of charge, including interaction with other flexibility markets;
- Assessing the prospect for making dynamic probabilistic predictions of both (i) the battery's required state of charge, and (ii) the probability of interruptions occurring;
- Updating the overall GB-level project business case by applying the valuation methodology.

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1 Introduction

Scottish & Southern Electricity Networks (SSEN) has commissioned TNEI Services (TNEI) to review the business case for a novel approach to improving the reliability of service to customers in rural and remote areas using the RaaS - Resilience as a Service - concept currently being investigated through an innovation project[6] funded through Ofgem's Network Innovation Competition (NIC).

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As part of the original submission for NIC funding, an initial business case and cost benefit analysis (CBA) were created to indicate the potential benefits of this approach. That work considered the case for RaaS over the very long-term, and across the entirety of Great Britain. TNEI originally supported SSEN in the preparation of this CBA and business case.

With the project now developing the detail of the concept, SSEN also require an enduring methodology for evaluating the business case for commissioning RaaS to support any specific substation within their network.

SSEN has therefore appointed TNEI to revisit and refine the business case, and to develop approaches for assessing the application of RaaS at individual substations, including mechanisms for valuing the service and determining appropriate payment structures.

This report is structured as follows:

- Section 2 provides context for our review, including a summary of the RaaS concept, a review of the NIC business case submission (including the approach, results, and discussion of gaps and limitations), and a discussion of comparable market-based services (including the Capacity Market and DNO flexibility services). Consideration is given to how these threads draw together, with discussion on opportunities for developing the business case and providing a valuation both for individual RaaS sites, and for the overall project.
- Section 3 presents our proposed methodology for valuing a RaaS service at a specific site, including a detailed articulation of the methodology, illustrative examples of applying the methodology to 24 prospective RaaS sites, and a discussion of the implications of this valuation analysis for the overall business case.
- Section 4 discusses the economics of RaaS payments and methods for establishing an appropriate mix of availability and utilisation payments.
- Section 5 discusses the role of forecasting within RaaS services, including forecasts of primary substation demand, and forecasts for when faults may be more likely to occur.
- Section 6 describes the opportunities for further work, building on the approaches presented.

[6] https://project-raas.co.uk

2 Context for this work

2.1 Resilience as a Service

The RaaS concept is designed to improve and maintain the reliability of remote and isolated networks, while minimising the need for carbon intensive temporary generation. Where communities are supplied by single circuit overhead lines due to the prohibitive cost of reinforcing the network across remote locations, security of supply can be lower than in urban or more densely populated regions of the network. Such areas apply alternative security of supply standards associated with ER P2/7 compliance, for example, 37 sites across SSEN's SHEPD northern network adhere to SSEN's approved alternative standard (PO-PS-037).

The RaaS project seeks to develop and trial a system that can quickly and automatically restore supply to customers in the event of a fault on the network, using services provided by a third party owned battery energy storage system, together with local distributed energy resources. The proposed scheme would support primary substations on the distribution network, which transform power from Extra High Voltage (typically 33kV) to High Voltage (typically 11kV).

This market-based solution would provide customers with an electricity service that meets all elements of the trilemma - sustainability (low carbon), affordability (low cost) and security.

2.2 RaaS NIC Business Case Submission

The project NIC submission to Ofgem in 2019 included an estimate of the potential benefits that RaaS might deliver to GB consumers, representing an initial business case for the concept. This subsection sets out the approach to calculating those benefits and the results of the associated CBA, then reflects on the methodology, including gaps in the approach and opportunities for enhancement.

2.2.1 Approach for the original CBA

The overall approach taken in the original CBA is set out in Figure 2.1 below, which TNEI produced as part of the NIC bid submission to Ofgem.

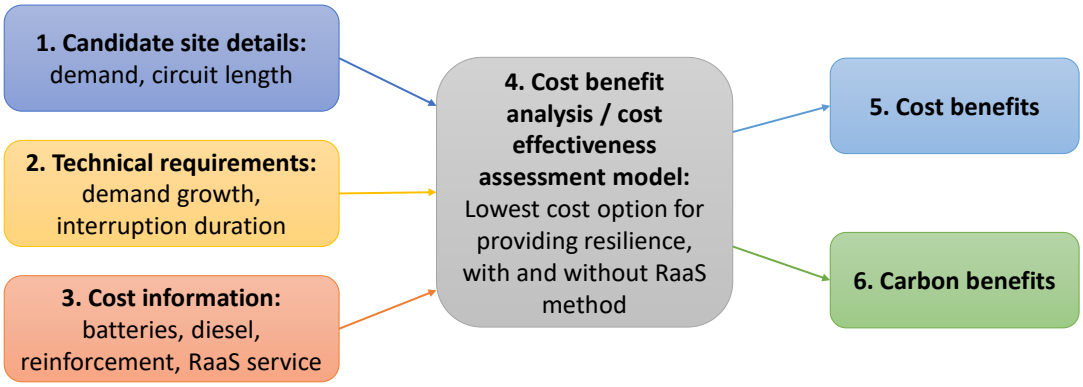


Figure 2.1: Overview of the original CBA approach

The CBA approach takes the following inputs:

1. Information on 114 candidate sites across GB, including sites from other DNO regions beyond SSEN's two licence areas.
2. Technical requirements for the RaaS service.
3. Information on potential costs for RaaS and alternative options, including conventional reinforcement and a DNO managing resilience with DERs which it owns (rather than via a third-party service).

The key assumption within the CBA is that each of the 114 sites would benefit from improved resilience. The three options considered for achieving this are:

- Reinforcement, with the addition of a second redundant circuit.
- The use of DNO owned energy resources that are only used for resilience (initially provided by diesel generators, but then by DNO owned batteries from 2028 onwards).
- The Resilience as a Service solution.

These inputs are processed in a CBA model, which then determines the potential benefits attributable to RaaS as a project.

The project CBA did not consider the actual costs of interruptions at each site, either in terms of the disutility[7] experienced by customers, which could be expressed in terms of Value of Lost Load, or the Interruption Incentive Scheme (IIS) penalties imposed on DNOs. The latter are payments calculated as a function of Customer Interruptions (CI) and Customer Minutes Lost (CML)[8]. To include these would have required significant time in processing and modelling data that might inform these costs, which would not have been possible in the timescales of the NIC bid. In addition, SSEN would not have been able to access this information at a GB wide scale, which would have significantly limited the assessment.

Each of the coloured and numbered blocks in Figure 2.1 is discussed in more detail below.

1. Identifying potential candidate sites

Candidate sites across GB were identified based on a detailed review of the Long-Term Development Statements (LTDS) of each of the GB DNOs, to find primary substations that satisfied the following four criteria:

- The current demand of the primary is relatively low (less than 10MW) - it was assumed that higher demands would require batteries that are too large to justify a RaaS scheme.
- There is no redundancy in the primary's EHV connection to the wider network (i.e., the substation is fed from a single circuit only).

[7] Disutility is a concept from economics, defined as "the adverse or harmful effects associated with a particular activity or process, especially when carried out over a long period". See www.lexico.com/definition/disutility

[8] Ofgem's RIIO-ED1 glossary of terms provides the following definitions:
"CI - Customers interrupted per year - The number of customers interrupted per year (CI). This is the number of customers whose supplies have been interrupted per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident.
CML - Duration of interruptions to supply per year - The duration of interruptions to supply per year (CML). This is the average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer."

- This single circuit is at least 5km long, as longer circuits would be: (i) more expensive to reinforce, and (ii) assumed to be more likely to experience more frequent interruptions, with an assumed positive correlation between circuit length and interruption frequency.
- The primary is in a fairly rural setting (confirmed by checking its location on Google Maps) since urban networks would be more likely to have more extensive HV network interconnection which could provide resilience in the event of an EHV fault.

An example site - Rissington primary, in SSEN's SEPD southern licence area - is shown in Figure 2.2. The primary has a single 13km circuit back to the wider ring network and a demand of 6.41MW. The map shows it is in the Cotswolds AONB[9], also the Rural-Urban Classification of the location of the primary from the 2011 census is "Rural Village", with the surrounding area defined as either "Rural hamlets" or "Rural town and fringe".

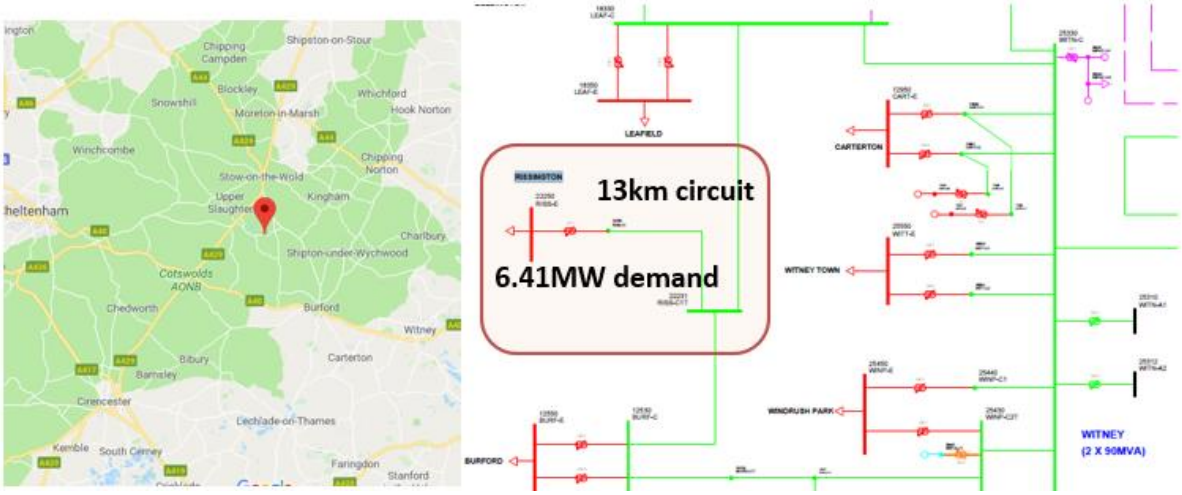


Figure 2.2: Rissington Primary schematic and map

Through application of the four assessment criteria to the 14 LTDSs, 114 candidate sites were identified. The breakdown of these sites across DNOs and licence areas is shown in Figure 2.3 (with a map showing the boundaries of each licence area given in Appendix A). As to be expected there are more candidate sites in licence areas that serve more rural locations (such as SHEPD, WPD South West, Scottish Power Distribution, etc), and fewer in those networks that have more customers (such as SPN, and EPN). Unsurprisingly, there are no candidate sites within UKPN's London network.

[9] Area of Outstanding Natural Beauty

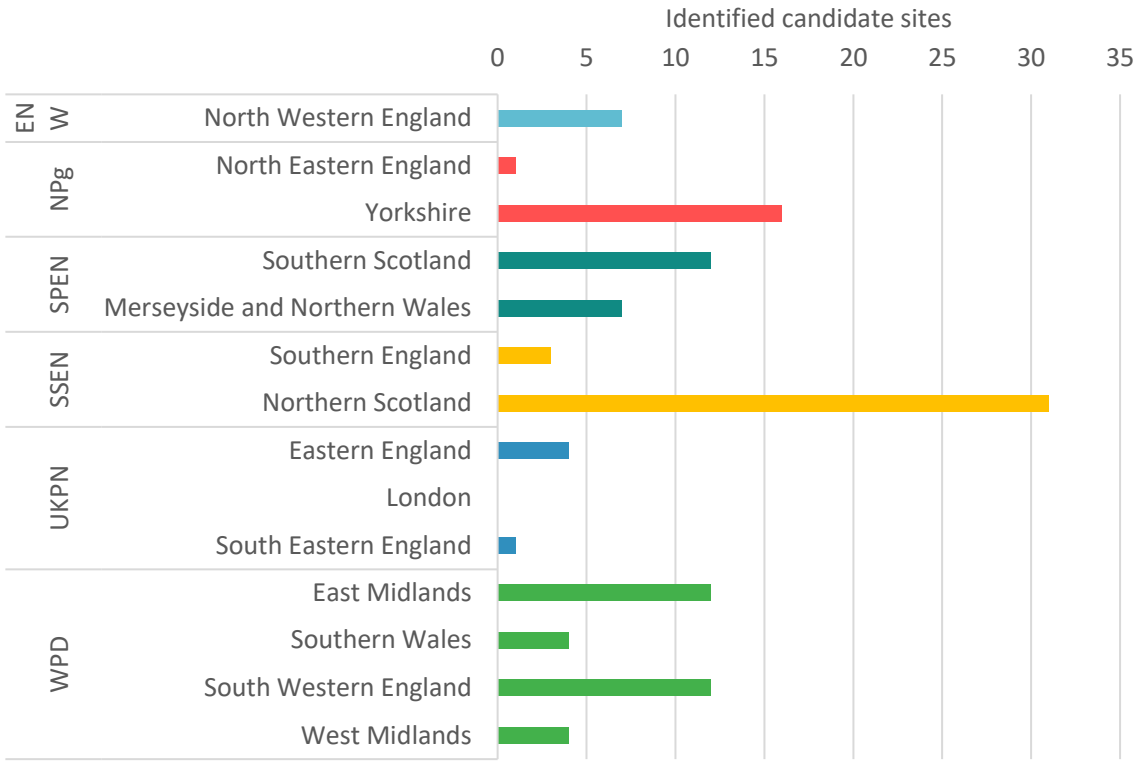


Figure 2.3: Number of potential candidate sites by DNO licence area

2. Technical requirements

When providing resilience through either RaaS or the alternative of DNO owned energy resources, the nature of the service/resources depends on the technical characteristics of the site. This is ultimately driven by the peak demand of the primary substation. Using the peak demand data, the CBA model determined:

- The required size of battery to ensure that RaaS can prevent faults of certain duration. At the time, analysis of some SSEN SCADA data suggested than a battery with 6MWh for every MW of capacity would be sufficient to cover the majority of power outages of up to 12 hours in duration.
- How the primary substation's peak demand may change in the future due to the electrification of heat and transport, which would impact the necessary MW and MWh size of a battery. This was based on some simple assumptions about After Diversity Maximum Demand (ADMDs) and new technology uptake curves from the various National Grid ESO Future Energy Scenarios10. Figure 2.4 shows example EV and heat pump uptake curves, and the resultant proportional increase in primary substation demand calculated based on these.
- The possible impact of greater deployment of distributed energy resources (DERs) by customers, including micro-generation and technologies such as Vehicle to Grid, which would reduce the burden on the battery for providing resilience (such that the same length of interruption could be managed with a smaller battery capacity). This was assumed to decrease the necessary MWh per MW of battery storage as the overall proportion of distributed and microgeneration increases, as shown in Figure 2.5.

[10] www.nationalgrideso.com/future-energy/future-energy-scenarios

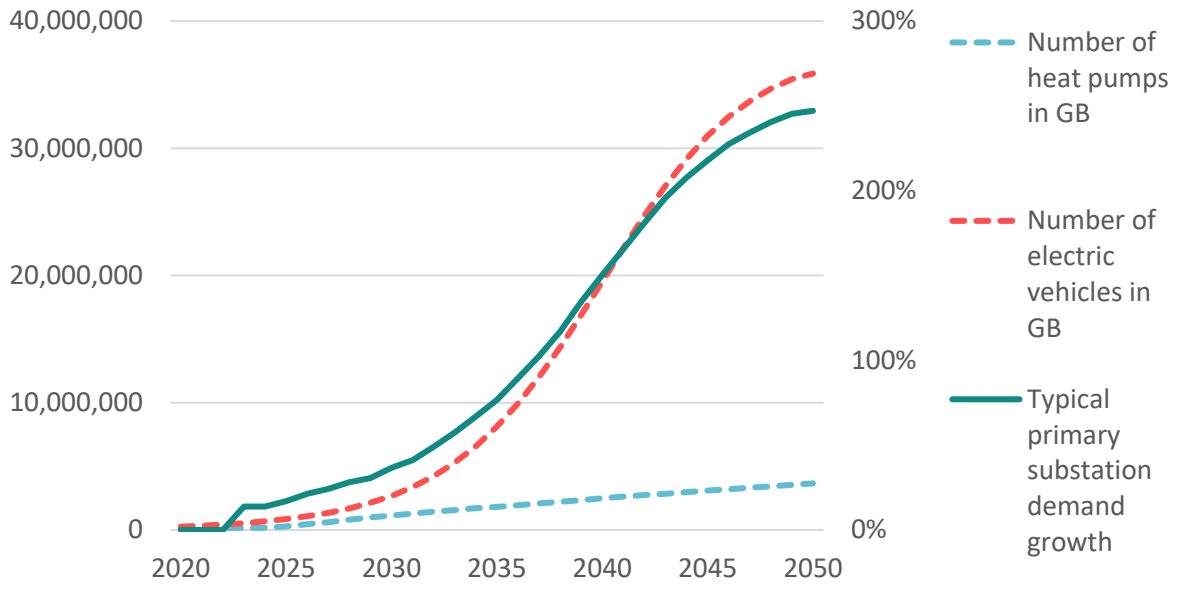


Figure 2.4: Technology uptake scenario assumptions and assumed demand growth

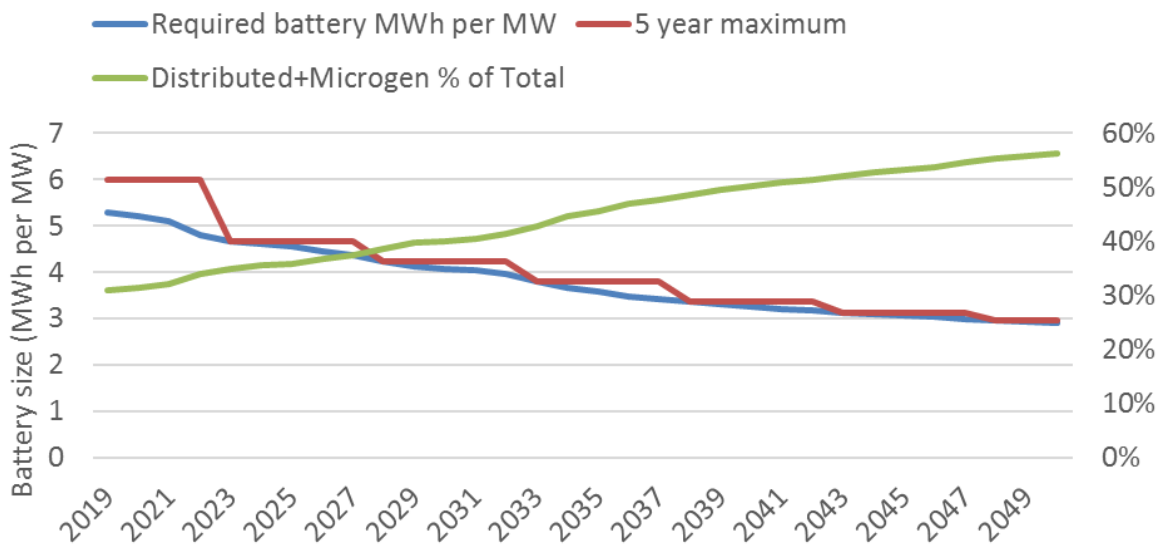


Figure 2.5: Assumptions about DER and RaaS battery capacity

3. Cost information

Figures for costs of conventional reinforcement were sourced from SSEN, with an assumption that reinforcement would be more expensive than is typically the case due to the rural nature of the sites in question. In practice, for some of the sites it is also likely that reinforcement would not be possible either due to access/local conditions, or the difficulty of getting planning permission for new overhead line infrastructure. To account for this, it was assumed that, for all of the candidate sites, some proportion of any new circuits would have to use underground cable.

Costs for batteries and diesel generators were sourced from publicly available references, which included projections for how battery costs are anticipated to decrease in the future.

For the RaaS service itself, an assumption was made about the fee that a provider would need to recover (in terms of £/MWh), which was combined with the technical assumptions described above to return a required fee in terms of £/MW. The required fee was assumed to decrease in-line with battery costs. The general assumption was that, within a single 5-year contract, RaaS would only need to cover a relatively small proportion of the capital cost associated with the battery (about 1/8th) as providers would be able to stack revenues with participation in other flexibility market services and would be able to continue to use the battery for other means after the contract had ended. Figure 2.6 shows the assumed annual fee required in terms of £k per MW for each 5-year block within the model (chosen to align with RIIO-ED2 and anticipated future price control periods), which diminishes both as battery prices fall, and as the increase in microgeneration and other DERs means smaller MWh batteries are needed to provide the same level of service[11].

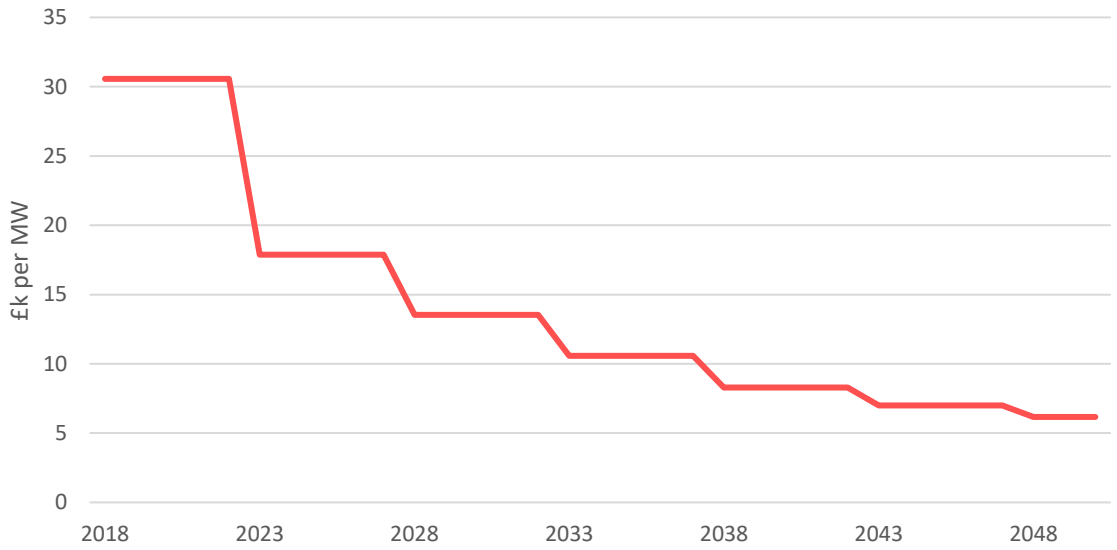


Figure 2.6: Assumed fee requirement

In addition, it was assumed that deploying the RaaS solution would require a one-off cost to the DNO of £250,000 per primary substation to set up the necessary infrastructure and IT systems.

4. Cost benefit analysis / cost effectiveness assessment

The cost benefit case (which may be more appropriately referred to as a cost effectiveness assessment[12]) for RaaS was then evaluated by comparing, for each site, the cost of the RaaS service with the two alternative options (reinforcement, and DNO owned energy resources). For simplicity and consistency, each solution was costed on the basis that it was present for the entire Ofgem RIIO-ED CBA period from 2023 to 2050. For each individual site, the lowest cost solution was identified.

Figure 2.7 demonstrates the output of this cost effectiveness assessment, with a scatter plot of peak demand vs EHV circuit length for all of the 114 candidate sites. This demonstrates that in many of the candidate sites, RaaS is lower cost compared to both alternative options and therefore offers a

[11] It is worth noting that in addition to establishing the DNO business case for RaaS, a key aspect of the ongoing project work is to develop a detailed understanding of the potential for revenue stacking in other markets, and the associated fee that may be required by a RaaS Service Provider. That work is being undertaken by RaaS project partner E.ON, and is outside of the scope of this report.
[12] The phrase 'cost effectiveness assessment' acknowledges that the submission to Ofgem did not quantify benefits (i.e., value) to consumers of reducing interruptions, rather it identified the most cost-effective way to achieve the outcome of a reduction in interruptions.

potentially effective means of improving resilience (subject also to the potential financial benefits associated with VoLL for avoided outages or reduction in CIs/CMLs). However, there are sites where RaaS does not represent a cost-effective option for improving resilience as it would be more expensive than the alternative options.

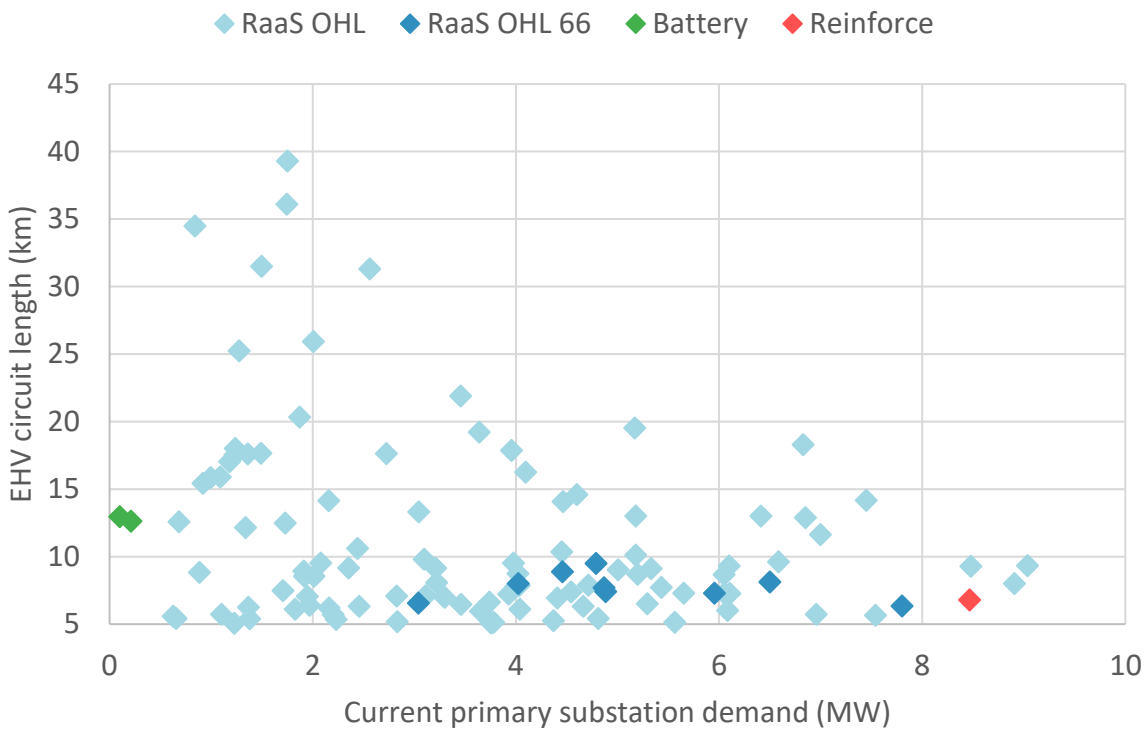


Figure 2.7: Illustration of the lowest cost resilience option for each substation from the original NIC submission analysis

5. Benefits compared to costs for alternative options

By comparing the cost for each site with RaaS and without RaaS (i.e., taking the cost to apply the lowest cost option between reinforcement or DNO owned energy resources), the benefits of the RaaS for each site were determined. Aggregating these benefits across all 114 sites then returned the total benefit of the project, which was therefore used in the NIC business case.

6. Carbon benefits

In addition, RaaS benefits associated with a reduction in carbon emissions were determined. These were derived from assumptions regarding the carbon associated with the two alternative options, i.e., the embedded carbon associated with reinforcement, or the carbon emissions due to running standby diesel generators. It was assumed that any embedded carbon associated with the RaaS battery scheme would be negligible.

2.2.2 Results from the original CBA

The original CBA that accompanied the NIC submission determined a potential net benefit of £146m by 2050 with RaaS deployed at 111 of the 114 potential candidate sites identified, giving an average benefit per site of around £1.3m.

2.2.3 Gaps and limitations of the original approach

There are several areas where the approach taken to estimating benefits had to be simplified or abstracted during the original assessment, for reasons including:

i. The creation of an approach and results that could be readily explained within the RaaS submission and was transparent and explainable for Ofgem and other stakeholders.

ii. So that the same approach could be applied to all DNO licence areas using information that was readily available in the public domain.

This section of the report describes the limitations of the approach and simplifications made, including:

- Limitations that are fundamental due to the approach taken.
- Elements that were simplified in order to incorporate them within the CBA.
- Inputs and assumptions that were made during the NIC submission which may now, or soon, be possible to update.

2.2.3.1 Fundamental limitations

Alternative options

The original CBA assumed that resilience must be improved by some means, with one of the possible alternatives to RaaS being reinforcement of the existing network to add redundancy. In practice, by nature of the fact that the sites expected to be suitable for RaaS currently have a single feeder as it is not cost effective to construct a new second line, this is unlikely to be a realistic option in the majority of cases. Further, some sites may be particularly scenic, or otherwise sensitive to environmental impacts, which precludes the construction of a second line. The CBA sought to account for this by including high costs for reinforcement (including a need for undergrounding part of the route for reinforcement), however it is acknowledged that this is quite a simplistic approach.

In addition, the DNO owned energy resource alternative was set up to consider *either* DNO owned diesel generators *or* DNO owned batteries. On reflection, it may be more realistic that both need to be utilised together in order to provide resilience, with a battery providing the ability to ride through a fault, and the diesel generator providing supplies for longer interruptions.

IIS costs

In many cases, a more realistic alternative would be that, for some sites, resilience continues to be poor, and customers experience interruptions, resulting in associated IIS payments for the DNO and disutility for the customers. This can be similarly captured within a cost benefit analysis which estimates the cost of procuring the service and compares this to an expected cost (i.e., the probability-weighted average costs over all possible outcomes) of IIS payments that would be experienced without the RaaS service. This could, in principle, be done for every potential RaaS site in GB, with many of the principles likely being very similar to the existing CBA, e.g., the approach to calculating net present values, extrapolating service provider fees, etc. However, we believe that doing this for every candidate network would represent a significant departure from the original CBA approach.

A key challenge here (although it would not be insurmountable in principle) would be to derive robust figures for CI & CML payments associated with each potential site. We expect that DNOs will have a good understanding of typical CI & CML payments per customer, and possible historic trends in these. However, RaaS is very unlikely to be relevant for sites that only experience typical levels of

interruption. Characterising the levels of interruption for sites with unusually low levels of resilience could be very difficult to do. For example, for a site where the various blackout risks amount to an expected value of one event every five years, it is true that one event in a 5-year historical record is the most likely outcome. However, while the probability of observing one event in such a record is just over 40%, the probability of no events is over 30% and the probability of 2 events is over 20%. Reversing this analysis, it can be appreciated that while observing one interruption event in a 5-year record means that 1-in-5 years is the most likely value for the expected value of risk, the likelihood of the true expected risk being as low as 1-in-10 years or as much as 1-in-3 years are also quite high. For networks that experience more frequent interruption events, considerable uncertainty remains, however to a relatively smaller extent.

In summary, inferring the CI/CML risk is more complex, particularly where there are only a few years of fault data available and relatively low numbers of events. Even where longer datasets are available, other challenges present themselves. For example, fault frequencies from ten years ago may not be representative of fault frequencies that are experienced now, or will be experienced in the future, due to e.g., changes in asset age and health, demand levels, and weather patterns. There is therefore a tension between the need for longer records to reduce 'sampling uncertainty', and the need for shorter records to ensure the risks are not outdated - with a happy medium required.

In practice, this tension could be resolved - or at least mitigated - through the adoption of appropriate statistical techniques and input from subject matter experts. We discuss and demonstrate some simple but effective implementations of this within Section 3.

Figure 2.8 shows the historic number of faults affecting four prospective RaaS primary substation sites in five reporting years (which run April to March). These examples demonstrate some of the difficulties that arise when trying to characterise the frequencies with which faults occur. For example, it appears that Kinloch experiences fairly regular faults (with 3 per year in 2016, 2017 and 2018 and 6 in 2019), although there are none in 2015. It is easy to imagine that you might characterise this with a probability distribution that says 3 faults per year is the most likely outcome, but that outcomes in the range of 0 faults per year to 6 faults per year is also possible (with smaller but not extremely small probabilities of occurrence). A similar conclusion could be drawn for Arisaig.

However, the historical data for Pollachar and Port Askaig is more difficult to interpret. Pollachar experienced no faults in the 2015 - 2018 reporting years, but then 5 in 2019. Similarly, Port Askaig experienced between 0 and 2 faults in 2015 - 2018, and then 11 in 2019[13]. Characterising these distributions could be much more difficult; how can we say with confidence whether 11 faults per year is a 1-in-5-year event for Port Askaig, or a 1-in-10-year event, or a 1-in-100-year event? This is not to say that statistical modelling cannot be applied, but only that results must be understood in context and with potentially significant caveats.

[13] It may be relevant that both Arisaig and Pollachar are primaries on Scottish islands.

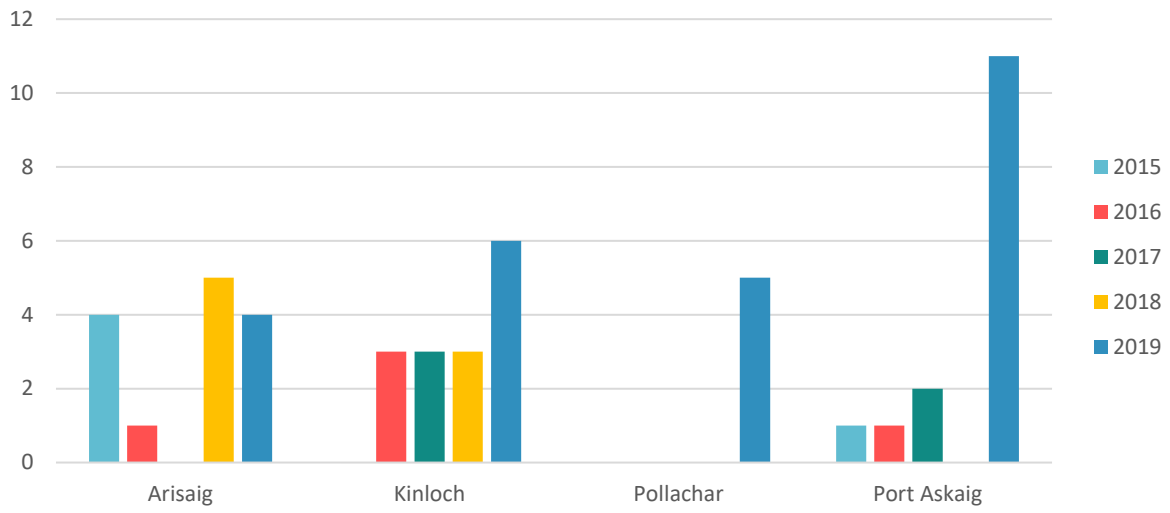


Figure 2.8: Historical faults per year for four prospective RaaS sites

Even once this data is collected and processed for the SSEN licence areas, consideration needs to be given to the other GB DNO regions. To develop a GB-scale cost benefit analysis, the RaaS project would be dependent on sourcing detailed fault data from each of the other DNOs. In addition to the base data, interpretation is required to understand the meaning of data (e.g., understanding whether multiple HV outages are linked to one EHV outage). Sourcing and interpreting the data internally within SSEN for the refined analysis presented within this report has required considerable contribution from SSEN engineers, therefore it is easy to imagine this could present a barrier to obtaining similar data from all other DNOs.

Disutility of interruptions

It is also recognised that CIs & CMLs may underestimate the true impacts of interruptions on customers, particularly interruptions which have longer durations.

Recent research undertaken by ENWL through its VoLL 2 project[14] has shown that there is a tendency for customers to experience higher overall disutility if faults occur more frequently, over a wider geographic area, or with longer durations. In other words, the total disutility - and therefore Value of Lost Load (VoLL) - of long, frequent and wide area blackouts is greater than the sum of disutility from a larger number of shorter, less frequent and more local blackouts, even when the total duration of interruptions for both are identical. IIS does account for some of these impacts - a separate penalty on the number of interruptions should disincentivise higher frequencies of faults, or faults that affect more customers - but the nature of applying a fixed figure across all CIs & CMLs does not reflect the non-linear way that the VoLL to customers increases, for example the approach does not account for the impact of higher duration faults.

As a further consideration, whilst customers who experience very high levels of interruption tend to report that they 'have got used to' such events since they are a more typical aspect of life, it is recognised that this might change in the future as heat and transport are electrified creating additional reliance on electricity supplies. Such considerations could very readily lead to higher levels of VoLL, and/or values which change seasonally (e.g., due to higher demand for electrified heat during winter months).

[14] www.enwl.co.uk/go-net-zero/innovation/smaller-projects/network-innovation-allowance/enwl021---voll-2/

Optionality value

The original CBA does not attempt to quantify any "optionality" value associated with the RaaS service, by which we mean the possible value associated with using a service to defer reinforcement until there is more information and certainty about future requirements. For example, RaaS could be used in cases where existing assets are reaching the end of their lifetimes and faults are occurring more frequently, but, because of uncertainty about implications that the energy transition (e.g., increasing levels of distributed generation, or uptake of technologies associated with the decarbonisation of heat and transport) may have on demand patterns, it is not clear what type or scale of asset replacement would be justified. In this case, a RaaS service would help protect customers from the negative consequences of interruptions, whilst providing time to make a more informed decision on committing to the capital cost of any particular reinforcement plan.

2.2.3.2 Simplifications

Half-hourly demand data

The analysis undertaken for the NIC submission did not explicitly account for varying seasonal and daily patterns in primary substation demand. Rather, during bid preparation, the RaaS project team analysed some historic SCADA data for a few substations to indicate the potential energy storage capacity required to provide resilience for a proportion of possible faults, with this figure applied generically across all the candidate sites. A more detailed assessment of half-hourly data for individual sites would provide a significant refinement to the analysis, however this was not possible for the NIC submission.

Changing demand profiles

Similarly, there was no explicit "bottom-up" accounting for the way that demand profiles could change in the future, apart from assumptions about increasing peak demand and uptake of decentralised energy resources. It was assumed (as described in the 'Technical requirements' section above) that increasing adoption of decentralised energy would reduce the required size of energy storage, but this was a "top-down" assumption, not derived through detailed consideration of the possible daily patterns of use of new technologies such as electric vehicles and heat pumps. As above, it is unlikely that a more detailed consideration of demand patterns could have been adopted within the framework used to provide the CBA for the Ofgem NIC submission.

2.2.3.3 Revised inputs and assumptions

RaaS service definition

One of the key inputs into the original CBA is the assumption about the required battery size as a function of the battery installed capacity (i.e., the volume of MWh of storage required for every MW of import/export capacity). This was a key input into deriving the assumed service fee based on a £/MWh amount (with this linked to the assumed £/MWh cost of batteries).

Within the NIC submission to Ofgem, it was assumed that the battery for each site would initially need 6 MWh of energy storage for every 1 MW of peak demand, with this gradually reducing as the proportion of decentralised energy resources increased within a Future Energy Scenario. This figure was based on analysis of historic SCADA data by the RaaS project team during the bid preparation, which suggested that a battery that provided six hours of storage at peak would be sufficient to cover a 12-hour interruption for 90% of the year.

However, the definition of the service has since evolved, with the current base assumption that the RaaS service should be able to provide support for four hours of demand. To cover this at peak times, the battery would require 4 MWh of energy for every 1 MW of peak demand, rather than 6 MWh.

Service fees

Another key input into the NIC submission CBA is the assumed required fee for the RaaS service, and how this will change in the future. As described above, the fee was assumed to be set on a £/MWh basis (in terms of the necessary MWh size of the battery). For deployment in future years, the underlying £/MWh fee was assumed to reduce in line with a reduction in battery costs. At the same time, the number of MWh required for every MW was assumed to reduce due to a greater presence of distributed energy resources, and the peak MW of each site was assumed to increase due to heat and transport electrification.

The assessment then looked to return approximately 1/8th of the battery's capital cost over a single five-year contract.

This assumption was considered to be reasonable for demonstrating potential benefits as part of the NIC submission, however, it was clearly recognised at the time that insight into the fees that would be required by a RaaS Service Provider would require detailed evaluation within the project itself. Accordingly, at the time of writing E.ON are undertaking an assessment of the potential for stacking revenues in other flexibility markets, and what implications that may have for the RaaS fee. Alongside this, the TNEI work presented within this report considers approaches for valuing a RaaS solution from a DNO perspective. These views can then be compared to identify overlaps or gaps and understand how to make RaaS as attractive as possible for both parties. Once the indicative fee level is available from E.ON's work it can be used to further update the RaaS CBA model.

Candidate sites in SSEN and GB

While assessing benefits for individual primary substations is, of course, important, being able to demonstrate how these benefits scale across GB was critical for the NIC submission. This was demonstrated through the identification of over 100 sites across thirteen of the fourteen distribution licence areas in the country that represent potential candidate sites suitable for the application of RaaS. However, this analysis was, by necessity, based on publicly available information about the other DNO networks.

One option for refining this appraisal in the absence of detailed information across all DNO licence areas may be to explore sensitivities to see how the GB-scale benefits change based on the number of sites, potentially using detailed SSEN data about historic CI & CML costs to make inferences about the overall number of sites. It is also noted that Costain will review the potential for wider potential applications of RaaS, however, the output of this exercise is not available at the time of writing this report.

It is also worth recognising the more detailed development of the service valuation methodology and payment structures (or the service design more generally) could lead to the number of potential sites changing. For example, if there is an option for a lower cost service in cases where faults are rarer (for example, the network is only at risk during planned outages during the summer), or a lower cost option may not cover 90% of outages but still represents a significant benefit to customers, then this could potentially lead to a very large set of additional candidate sites.

2.3 Comparable resilience-related services

This subsection provides an overview of some comparable market-based services that already exist, or are being developed, within the electricity sector, including information on how they are valued and how payments are made. Potential alignment with a RaaS service is also considered.

2.3.1 DNO Flexibility Services

The GB DNOs are collectively developing generic flexibility services through the ENA's Open Networks[15] project (ON-P), with four services currently defined. These are described in the table below.

Table 2-1: Summary of DNO Flexibility Services

Service	Type	Notification Timescales	Frequency	Duration	Example
Sustain	Pre-fault	Months or years	Daily	Hours	Regular constraint management, with providers providing peak management for pre-defined time periods.
Secure	Pre-fault	From minutes to months	Daily to weekly	Hours	Peak shaving, with dispatch either scheduled days or months in advance, or in real-time.
Dynamic	Post-fault	Minutes	Rare	Hours to days	Customers changing their import or export quickly following a network outage to keep assets within limits.
Restore	Post-fault	Minutes	Rare	Hours to weeks	Customers remaining off supply in the event of a fault until the network has been restored.

Sustain and **Secure** both relate to day-to-day operational activities, with the main difference being the way in which the services are planned. **Sustain** requires a very predictable and regular type of behaviour from a service provider, with dispatch agreed far in advance. **Secure** is planned and dispatched over much shorter timescales, from months ahead potentially down to fifteen minutes. Both are "pre-fault" services, which aim to prevent the exceedance of voltage or thermal limits on the network.

In contrast, **Dynamic** and **Restore** are both post-fault services. **Dynamic** aims to ensure that if a fault does occur, there are no adverse impacts on network assets due to excessive voltages or currents. **Restore** aims to help a DNO prioritise network restoration across areas in the event of any interruptions, by allowing customers to earn a service payment if they are willing to wait longer to be reconnected.

Prior DNO & ESO stakeholder engagement work undertaken by Costain to ascertain views regarding wider flexibility markets and the alignment of RaaS to these markets indicated a consensus that RaaS is most closely aligned to the **Restore** service (supporting remote or rural areas with less conventional

[15] www.energynetworks.org/creating-tomorrows-networks/open-networks

network resilience), however it may be that RaaS forms a distinct DNO product, or particular application of the **Restore** product. In any case it is important to ensure that an asset contracted to a DNO for one type of post-fault requirement (RaaS) is not contractually unable to support a response to other post-fault scenarios.

2.3.1.1 Service valuation

In 2020, the ENA (with support from the consultancy Baringa) developed a "Common Evaluation Methodology" for valuing the four established Open Networks flexibility services. This methodology is described in a report authored by Baringa and published by the ENA in December 2020[16]. For **Sustain, Secure, and Dynamic**, the approach is based around valuing the savings associated with deferring reinforcement for a set number of years, based on DNO defined flexibility requirement. This deferment of reinforcement provides time for a DNO to obtain additional information on changes in demand patterns to make a more informed decision on committing to the capital cost of reinforcement plans. This ENA/Baringa evaluation methodology can report outputs in two different forms:

- If the user enters a pre-specified price for the flexibility service, then the methodology can output the net benefit of using the flexibility service to defer the reinforcement.
- If the user does not enter a pre-specified price, then the methodology outputs the maximum price that should be paid for flexibility, as justified by the value of deferring the reinforcement.

It is worth noting the implicit link that this draws between the valuation of a service (i.e., the most that can justifiably be paid for that service) and the net benefit of procuring that service (which manifests when services are provided for less than the maximum price). It is also worth noting that this requires a pre-specified, known price.

Although it is a secondary use case, the ENA/Baringa methodology can also be used for the Restore service. In this case, the measure against which the service is valued is the CI & CML payments made through the IIS scheme. However, when used for Restore, both the volume of CIs & CMLs and the flexibility requirements need to be determined on a site-by-site basis by the DNO, and the approach for determining these is not currently part of the Open Networks methodology.

2.3.1.2 Service payments

At present, the basis for payments for the four Open Networks products is still being developed and standardised. An Open Networks report on Revenue Stacking from 2020 gives the following summary regarding potential payment structures:

- Sustain: "Scheduled well in advance for a fixed fee.".
- Secure: "Predominantly paid based on utilisation, but with some use of availability payments also".
- Dynamic: "Low availability payments and high utilisation payments".
- Restore: "Low availability payments and high utilisation payments".

These principles suggest greater use of availability payments for services that are scheduled further in advance, and utilisation payments for those that are scheduled closer to real-time (although it is also

[16] www.energynetworks.org/industry-hub/resource-library/open-networks-2020-common-evaluation-methodology.pdf

possible to interpret this in terms of the frequency with which the services are required, with **Dynamic** and **Restore** having higher utilisation payments and being required less frequently).

While the Common Evaluation Methodology can calculate a maximum justifiable fee for a flexibility service, it is not clear from the information that we have reviewed whether this goes as far as to determine separate utilisation and availability payment fees.

2.3.2 Capacity Market

The Capacity Market was introduced in GB as part of the Electricity Market Reform (EMR) following the Energy Act in 2013. For the past several decades, GB has not experienced a system shortfall due to insufficient generation, however with the changing nature of the generation mix, and demand profile of consumers and new technologies, ensuring long term security of supply was a key concern within the EMR. A perfectly operating electricity market would provide the right signals and incentives for investment in reliable capacity; however, this may not be the case in practice, particularly for markets (such as GB before the Capacity Market), where only MWhs at a specific time (not MWs) are traded. When the market signals are not effective, a "missing money" problem may develop with respect to delivering adequate reliable capacity for ensuring security of supply.

Procurement of capacity in the Capacity Market is managed by National Grid ESO, although several organisations are involved in its design, delivery, implementation and ongoing review, including Government and Ofgem. The approach taken to procuring capacity in the Capacity Market is continually evolving and is a frequent topic in academic research, with several different approaches considered before implementation.

This process has been designed to ensure security of supply by providing payments for reliable sources of capacity (both generation and demand response) alongside traditional payments for electricity generation. The amount of generation capacity required by the system (the 'capacity to procure'), and several other decisions (such as the de-rating factor of certain assets) are made by the Secretary of State. There is therefore an inherent political element to the decisions made in the Capacity Market, including in how it was designed.

Currently, conventional generators, interconnectors, demand side response, storage and, from 2019, renewable generators are eligible entrants into the Capacity Market, each with appropriate de-rating factors. However, renewable generators are only eligible to participate if they do not already receive payments through Contracts for Difference (CfD), as this would distort market competition. Capacity providers can 'stack' revenue streams from other system services, for example system balancing services including frequency response. However, one caveat is that generators providing Short Term Operating Reserve (STOR) are not permitted to participate in the Capacity Market at the same time as delivering STOR and would therefore have to opt out of STOR to access revenues from the Capacity Market at any point in time. STOR providers are able to perform ancillary services outside of their contracted availability window, so long as this does not impact their ability to provide STOR.

The procurement of firmly available generation capacity through the Capacity Market is split into two auctions, with most of the generation capacity procured at T-4 (4 years ahead of time) and the remaining volume at T-1 (1 year ahead of the delivery year). The volume to be procured at T-1 will only become clear prior to that auction.

Capacity auctions also follow a 'descending clock' format, starting at a maximum offer of £75/MW and reducing until the minimum price is reached, where the capacity offered by potential providers matches the predetermined capacity to be procured. A provider exits the auction at the lowest price

they are willing to accept an agreement at or stays in the auction and accepts the final price that is reached and secures a contract for their offered capacity for the delivery year of the auction.

If successful in the auction, an existing provider may receive a 1-year contract for the delivery year, alternatively this may be a 3-year contract if refurbishment of the generation asset is required, and new builds may receive 15-year contracts. In a given delivery year, capacity providers are then required to deliver the amount of capacity that they bid at any time it is called upon by National Grid ESO, with Capacity Market notices being issued if there is a risk of a capacity shortfall. Capacity payments are made as monthly throughout the year, but providers are subject to penalties if they fail to deliver when called upon. The delivery year runs from 1st October to 30th September.

2.3.2.1 Service requirements and valuation

The term 'adequacy' refers to the ability of the power system to meet demand in the long term. A system is adequate if there are enough assets, generation and transmission, to meet demand at all times, given that none of them are perfectly reliable.

Historically this supply standard was a deterministic derated capacity margin (that is, the margin between the peak demand and total de-rated generating capacity) however through Electricity Market Reform (EMR) activities this has now been updated to a loss of load expectation (LOLE) measure which better captures the dynamic nature of the system behaviour.

Probabilistic modelling is therefore used for system adequacy assessment in the Capacity Market to capture the stochastic nature of the power system, to allow for uncertainty in how both generation and demand will evolve in future, and to account for the fact that a capacity shortfall is a high impact but very low probability event.

Within this, a set of future scenarios are studied, where installed generation mix, interconnector capacities, asset reliability, and demand profiles are predicted one to five years ahead of time. The power system is then analysed to determine the likelihood of having insufficient generation to meet demand in these scenarios (experiencing a system shortfall), and these results inform long term planning decisions for what capacity should be built to ensure a given level of reliability.

For example, one reliability standard metric, loss of load expectation (LOLE), represents the number of hours per annum in which it is statistically expected over the long-term that supply will not meet demand (with a three hours per year LOLE target in GB). This is the number of hours the System Operation (SO) is expected to need to manage system balancing beyond normal market conditions.

There are significant uncertainties associated with adequacy assessment, particularly surrounding the prediction of future demand as this is impacted by several factors including consumer habits, the economy, and the weather. Increasing penetrations of renewable generation and uptake in new technologies associated with the electrification of heat and transport increase the uncertainty in future projections, and the variability of generation output, which must be incorporated probabilistically into adequacy calculations to reflect the potential changing nature of system shortfalls and therefore the risk of experiencing customer black outs.

Adequacy assessments, alongside full dynamic dispatch analysis, form the probabilistic modelling process for determining the capacity to be procured through the Capacity Market to ensure the security of supply standard is met. The level of capacity needed to fulfil the LOLE target of three hours per year is one of the key inputs into the Capacity Market auction and is therefore critical in setting the £/kW value of the service.

2.3.2.2 Service payments

Following the capacity auction and agreement of contracts, payments are made monthly throughout the delivery year. Providers who have secured contracts for this service receive the auction clearing price for the capacity they are contracted to provide but are subject to penalties if they fail to deliver when called upon by National Grid ESO. Penalties are capped at 200% of monthly payments, and at 100% of annual payments.

2.3.3 Relevance for RaaS

There are several points worth noting from the Capacity Market and the Open Networks defined DNO flexibility services that could have relevance for RaaS.

- **The links between benefits and valuation:** The Common Evaluation Methodology (CEM) used for valuing reinforcement deferral for the Sustain, Secure and Dynamic DNO services demonstrates the link between valuation of the service and the benefits of that service. Essentially, benefit is derived from flexibility services by procuring them for total prices that are less than the maximum justifiable price, which is pegged to the value to the DNO (and its customers) of having the service.
  - It is similarly worth considering whether the same methodology can be used for RaaS to value the service and to determine the benefits associated with the service and establish a value. Although, as with the other flexibility services, this approach would require knowledge of the prices associated with the service.
- **Valuing interruptions with CIs & CMLs:** The Restore service demonstrates a case where the penalties associated with interruptions (CI & CML payments) are used to value the service on the basis that this these penalties would be incurred were the Restore service not used.
  - In practice, this is likely to be the case for RaaS for many primaries: without the service, customers will continue to experience interruptions and the DNO will have to make payments through the IIS. Therefore, using CI & CML payments (or some other measure of the disutility of interruptions) is considered to be important within the valuation for RaaS.
  - However, as discussed above, developing a robust understanding of the level of CI & CML payments at present and in the future has a number of challenges, and the CEM for Restore does not prescribe how this should be done.
- **Mixing availability and utilisation payments and penalties:** The four Open Networks DNO flexibility services include blends of payments based on both availability and utilisation, although we have not been able to source the rationale for determining the balance between availability and utilisation payments within our review. The Capacity Market is similar, with an upfront fixed fee paid on a £/kW basis, but with penalties that apply in the event of non-delivery. It is easy to see that RaaS services could also employ a mix of availability and utilisation payments, as well as the potential for non-delivery penalties.
- **The use of probabilistic simulation:** Probabilistic simulation is a key part of determining the requirements for the Capacity Market, due to the increasingly stochastic nature of the power system and the fact that lack of adequacy is fundamentally a high impact but low probability event. Interruptions at RaaS substations are lower impact, and higher probability, but still rare enough that they could justify the use of a probabilistic simulation approach.

2.4 Opportunities for site and project business case development

2.4.1 Value of lost load

The most significant enhancement opportunity for the business case - related to both individual prospective RaaS sites and the project as a whole - lies in the ability to produce a direct valuation of the cost and/or disutility associated with the interruptions which RaaS seeks to mitigate. This is a key distinction from the original business case, which compared alternative approaches to reducing interruptions, and reflects the fact that RaaS is intended to be targeted at sites where conventional reinforcement or standby generation are known to be prohibitively costly. Therefore, understanding the cost of these interruptions is a more appropriate basis for understanding the benefits that RaaS will provide to customers. This will be particularly important as electrification of heat and transport continues, potentially increasing customer reliance on or the expectations associated with their electricity supply.

As noted above, one way to value interruptions would be to consider the CI & CML penalties experienced by a DNO under the IIS mechanism. These are the actual costs that DNOs incur due to interruptions, so are directly comparable with alternative costs that a DNO might incur to procure RaaS services to reduce these costs. Valuation based on IIS payments will require a DNO to know, or reasonably estimate, the frequency and duration of faults associated with the area of network being considered, along with the number of customers affected. The financial figure per CI and per CML is determined by Ofgem for each DNO. The assessment must also evaluate the ability of a RaaS scheme to mitigate such faults, based on the MW and MWh capacities to be procured. The CEM approach for the Restore service provides a precedent for the use of CI & CML payments as the basis of valuing a service.

However, CIs & CMLs is not the only option for valuing a reduction in interruptions. Clause 12 "Cost Benefit Analysis (CBA)" of Engineering Report 130 "Guidance on the application of Engineering Recommendation P2, Security of Supply"[17] describes the approach DNOs should take for assessing whether "the cost of the reinforcement or implementing security service contracts to comply with the requirements [of P2/7] are reasonable when compared with the improvements in the System Security that would be expected to be delivered". It then describes how the cost of supply interruptions to customers should be considered within this CBA by assessing the Value of Lost Load (VoLL), as follows:

"Expected Energy Not Supplied (EENS) is expressed in MWh over a specific time-period (e.g., a year). Using the concept of EENS, it is possible to monetise the shortfall in system capacity where VoLL has also been calculated since the EENS can then be multiplied by VoLL. Hence, a change in EENS rising from remedial actions may be assessed based on:

- VoLL= £17,000 / MWh; different values of VoLL can be used where deemed appropriate by the DNO,
- VoLL impact assessed for an appropriate period of time, relevant for the CBA".

There is therefore scope within the existing P2/7 and EREP 130 framework to use EENS and VoLL as the basis of valuing the business case of the RaaS service.

[17] Engineering Report 130 'Guidance on the application of Engineering Recommendation P2, Security of Supply' Issue 3, ENA, 2019
www.dcode.org.uk/assets/files/Qualifying%20Standards/ENA_EREP_130_Issue%203_(2019).pdf

In addition, EREP 130 allows for different values of VoLL to be used if deemed appropriate. This is particularly relevant for RaaS in light of the findings of Electricity North West's (ENWL) VoLL 218 study, which show that £/MWh VoLL increases both as the duration and frequency of interruptions increase. This research also suggests generally high values of VoLL than the £17,000 / MWh quoted within EREP 130.

2.4.2 Probabilistic simulations

ENWL's finding that the marginal VoLL increases for more frequent and/or longer interruptions also supports the use of probabilistic simulation as part of the RaaS valuation and business case assessment. VoLL is essentially a measure of disutility to customers, and the tendency to associate high levels of disutility with more onerous events that occur less frequently is a natural response due to the disruption of life experienced during such events.

This means that the expected VoLL when considering (in a probabilistically weighted way) all of the possible interruption event outcomes (considering both frequency and duration) across a period of a year, or ideally a sequence of years, will be higher than the VoLL of the expected (average) interruption outcome. Essentially, the total VoLL from e.g., one year with a single hour-long event then another with a single three-hour event, will be higher than from two years each with single two-hour events. It is therefore essential to capture the effect of all events that have low, but not negligibly low, probabilities of occurring and are very onerous when they do occur. This difference between results depending on when the averaging occurs can be expressed mathematically as:

$$\mathbb{E}[VoLL(ENS)] \geq VoLL(\mathbb{E}[ENS])$$

where $VoLL(\cdot)$ is the function that translates from energy not served in MWh to cost, and $\mathbb{E}[\cdot]$ is the expected value operator (averaging over all possible values of a random variable).

To develop this into a practical approach, i.e., to obtain a sufficiently inclusive and therefore accurate estimate of the probability distribution of the annual total VoLL, probabilistic (Monte Carlo) simulation of interruptions can be used. This allows the analysis to address the fact that there are possible combinations of fault frequency and duration which could result in very high disutility, even though these are relatively unlikely to occur. It also reflects the approach used within the Capacity Market assessments.

The additional benefit of a probabilistic simulation framework is that it allows us to also factor in the half-hourly demand profiles for each prospective RaaS substation. Crucially, there is also a clear potential for such profiles to be modified for analysis of future years based on scenarios for the uptake of new sustainable energy technologies.

2.4.3 Linking the valuation and business case

As with the ENA CEM, the method used to appraise the benefits of commissioning RaaS for a specific site can also be used to determine the maximum possible value of the RaaS service. As previously discussed, with the Sustain, Secure and Dynamic flexibility services, the same CEM methodology can either return (i) the benefit of using the service (if a price is provided), or (ii) the maximum price that should be paid for the service (if no price is provided).

For RaaS, a probabilistic simulation method could be used to determine the reduction (or expected reduction) in disutility of the service in terms of VoLL, and/or in terms of IIS costs. During the early stages of service procurement, this could be used to set the maximum amount that a DNO would be

[18] www.enwl.co.uk/go-net-zero/innovation/smaller-projects/network-innovation-allowance/enwl021---voll-2/

willing to pay for the service. Similarly, once a range of potential service fees and terms from potential providers are known, e.g., following a tender process, then the consideration of proposed fees and could be used to select the preferred provider and determine the overall net benefit of procuring the service.

When considering the GB wide potential for RaaS, in principle, this analysis could be repeated for many RaaS sites, and potentially for many years into the future, to determine the overall benefit of the approach. At present, however, this would require the following data that we do not currently have access to:

- Sufficient information about fault durations and frequencies for all potential sites, including those outside of SSEN's licence areas,
- A robust understanding of fee requirements for different levels of service, now and in the future, to which the service valuation can be compared.

The RaaS project will continue to consider these factors throughout the project.

3 Valuing the DNO business case for RaaS

This section describes our proposed approach for DNO valuation of the RaaS service in reducing unplanned interruptions. The service valuation determines how much it may be appropriate for a DNO to pay for a RaaS solution at any given location, and so is a key input into the quantitative business case assessment for a prospective site. As this supports both site selection and prioritisation (with regard to the potential benefit to customers), and the evaluation of quotes, it is expected that this analysis would be required before going out to tender for RaaS.

By valuing the impact on VoLL, as well as CIs/CMLs, of a 4-hour RaaS service (or indeed any chosen duration) and comparing this to the associated prices submitted by providers, DNOs could establish the cost-benefit case for a prospective service deployment. This approach could directly answer the question: 'is the required fee justified by the expected reduction in interruption costs?'. This could further be considered alongside other potential benefits, such as the reduction in carbon associated with a reduction in the use of temporary diesel generation. There are also other factors which may be less tangible and more qualitative in nature[19], such as the reputational benefit associated with improving resilience, or the wider benefits associated with the RaaS battery asset being able to support additional use cases, such as increased community use of local distributed energy resources.

3.1 Methodology

Fundamentally, the premise for RaaS - and the foundation of its business case - is that SSEN will offer payments to third party energy storage operators for the provision of Resilience as a Service to support primary substations that are vulnerable to supply interruptions. Such relatively low levels of resilience, or in other words relatively high outage incidence rates, will typically be due to a combination of factors such as areas supplied by a single feeder, and/or particularly long overhead lines and cables passing through areas subject to extreme weather events.

The concept is that the energy storage asset would hold sufficient capacity to provide a swift response to an outage due to a fault on the network, by supplying customers in islanded mode until the fault had been addressed, or until a temporary diesel generator had been transported to site for a longer term-issue. Depending on the source of the fault, this service may provide ride through capability, where no supply interruption is evident, or black start functionality restarting the local 11kV grid in islanded mode.

At present a DNO would seek to repair the fault or despatch a diesel generator to site according to the quickest way to restore supply to customers. The role of the RaaS solution is to respond very quickly after the event and provide power to all customers, potentially for several hours, allowing time for the DNO to fix the fault or despatch a temporary diesel generator to site. It must be noted that the required energy and power capacities for a particular primary substation can also factor in the presence of distributed generation connected to the associated network, as this will also be able to continue exporting to the network during islanded operation.

To establish the business case (which may be insufficient) for paying third party RaaS Service Providers to support network operation, several factors should be included within an ideal model, as follows:

[19] We do not consider such benefits in any more detail within the scope of this work.

1. The frequency and duration of outages for the primary substation, ideally including an understanding of whether the expected number of events and their typical duration might significantly vary year-on-year, or possibly over periods of several future years.
2. How these events translate into a probability distribution of potential financial impacts - whether IIS penalties applied by Ofgem, or VoLL impacts to customers.
3. How the presence of distributed generation influences the level of demand to be met by the RaaS scheme, and therefore the duration of service that could be provided, and the potential sizing of the storage capacity required.
4. How the availability of temporary diesel generators (including consideration of time to despatch) might potentially impact the unserved energy/CML associated with an outage, with and without RaaS.

It is recognised, however, that aspects of these modelling considerations will need to remain as simplified estimates at present, due to a lack of relevant historic data or established methods. SSEN data regarding the timing of historic outages, and therefore their frequency, is available and assumed accurate for customers connected to a subset of primary substations and 33kV feeders. Accurate data also exists regarding the duration of outages, the number of customers affected, and the cause of the event. The existence of this data means that the RaaS assessment is able to incorporate the first point in the list above (with the modelling of trends across the years being out of scope) within the analysis undertaken for this review.

Within the following subsections, we give a detailed description of the proposed probabilistic method for valuing RaaS, which draws on the review of comparable flexibility market services presented in Section 2.3 and includes illustrative inputs and outputs for a notional primary substation. A “realistic” set of results for actual prospective RaaS sites is also included.

3.1.1 Motivation for statistical modelling and simulation

Since outages are generally rare, even several years’ worth of data at a 30-minute resolution[20] - despite being tens of thousands of data points - may not necessarily be sufficient to accurately estimate the expected cost of outage events for a particular substation. The need to work directly and exclusively with historical records is also limited when seeking a risk-based view of the probability distribution of potential future costs.

To illustrate this, this paragraph considers a primary substation that experiences, on average, one blackout event every two years. Over a 5-year historical record, the most likely number of events is 2, which has a 26% probability of occurring. However, there is an 8% chance of zero events, a 21% chance of only 1 event occurring, or of 3 events occurring, and then there is a 13% chance of four events and 7% for 5 events (assuming statistical independence of events). This means that there is a fairly small but significant chance that 5 years of records show that there were no outages for a particular substation, however in the next five years there may be 4 or 5 events, despite no change in the underlying risk. Therefore, if SSEN, or other DNO, wishes to draw robust conclusions from the data, it is necessary to adopt an appropriate statistical model for the events and apply statistical inference on the data to establish the best parameter values for the model.

A simple approach to this would be to extract expected values for frequency, duration and number of affected customers - which are generally given by straightforward equations once the model

[20] Half-hourly data is a typical granularity for monitoring - we therefore consider faults of any duration and assume that load is constant within each 30-minute period.

parameters have been statistically inferred. However, this would only be appropriate if the associated VoLL cost per MWh was fixed. Similarly, if the relationship between unserved energy and cost were linear, it would also be possible to obtain summary statistics about the VoLL, such as the mode, median or standard deviation. This could be achieved by obtaining these statistics for energy unserved (according to standard formulas) and simply scale them all by the cost per MWh. However, this is not considered to be a good assumption to make since, as previously discussed, the disutility to customers of outage events increases non-linearly with frequency and duration.

In light of this, an enhanced way to evaluate the distribution of potential costs arising from outages, whether represented by IIS payments or VoLL with varying cost per MWh, is to examine sequential occurrences of outages, and the gaps between these events. When this method is adopted for rare events such as blackouts, the problem of a single historical record being far too small to come to a robust conclusion is even more pronounced than for predicting the number of events per year. The solution to this is to simulate events from the statistical model using Monte Carlo simulation, thereby enabling the generation of thousands of years' worth of synthetic records.

By using this method, each simulated year, or possibly each simulated short sequence of years, represents a set of outcomes of "what could happen", each equally likely, and each equally likely as the observed historical record of events. The expected VoLL and/or CI/CML penalty for a particular primary substation can then be estimated as the average impact from the thousands of simulations. Likewise, the 99th percentile, or any statistic of interest, can be evaluated.

3.1.2 Modelling of fault frequency and duration

To develop the model for RaaS the intention is to derive inputs which stochastically describe, for a specific primary substation, the frequency with which faults occur, and the duration of these faults.

These will be in the form of probability distributions which indicate:

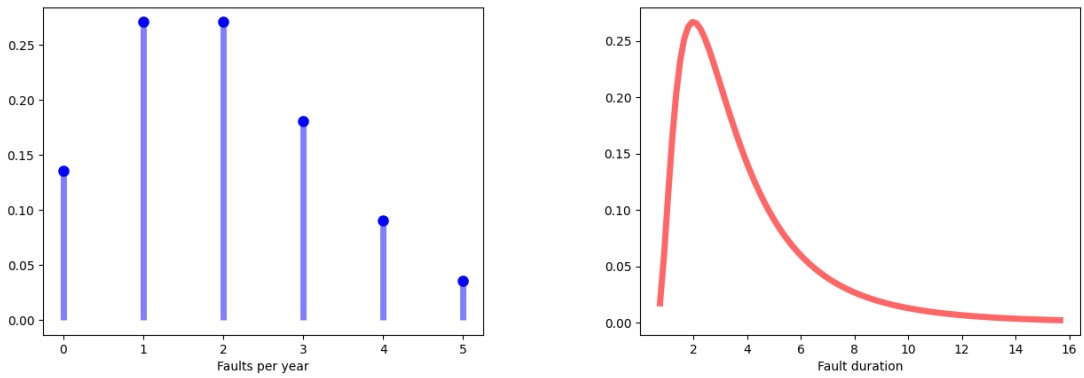
- The probability that X number of faults will occur within a given year.
- The probability that, once a fault occurs, customers are off supply for at least Y hours.

There is deliberately a difference between our modelling of fault and normal operational states here, in that we model the distribution of durations for fault states, but not for normal states. Modelling the distribution of durations for both would be much neater and more precise mathematically, with the frequency of events arising naturally and in an entirely consistent way. However, there is a barrier to doing this associated with rare events. Imagine that for a particular substation there was only one blackout event in the historical data. In that case we know the duration of the fault state, but not the full duration on the two instances of the normal state, because we do not know when the first normal state started (i.e., the timing of the prior fault beyond the window of data available) nor when the latter ended (i.e., the timing of the next fault). We can however extract precise values for the fault events.

To model the two states in this slightly inconsistent way, mathematically we assume that the time spent in the fault state is so much shorter than spent in the normal state that faults are essentially infinitely short, and therefore occur at a specific point in time. This allows the time interval between faults to be modelled as statistically independent both of each other and of the duration of events. This means that they can be very conveniently modelled as a Poisson point process, which helpfully and practically keeps the analysis and simulation very straightforward.

Example distributions are shown in Figure 3.1 below. Figure 3.1 (a) shows a Poisson Distribution (associated with Poisson point processes), which describes the probability that a certain number of

events (e.g., faults) will occur within a fixed window (e.g., a calendar year). This distribution is based on a long-run average of two faults per year. Figure 3.1 (b) shows the probability distribution function for fault duration, which to illustrate the method has been assumed to follow a skewed distribution. This example has a mode of two (i.e., the fault duration which occurs most frequently is two hours), and a mean of four (the average duration of a fault is four). This distribution has a very long right tail - most faults are very low duration, but much longer faults (e.g., several days) are possible[21]. It may prove more appropriate to choose a different distribution and within our more "realistic" illustrative examples, we have used the family of Weibull distributions instead of Lognormal distributions.



(a) Fault frequency **(b) Fault duration**

Figure 3.1: Example distributions of fault frequency and fault duration

The distributions in this illustration have been assumed based on our understanding of possible fault rates and durations observed within historic data provided by SSEN. However, since faults are generally quite rare, even for higher than usual rates on specific sections of the network, it can be difficult to understand the true distributions. Therefore, we believe it would be prudent to infer these distributions using a regression model for the following reasons:

- This would consider the historic data from all locations within a single model, to increase the number of samples for fitting a model.
- This model would relate the frequency and duration of faults to those factors which are suspected of affecting these, such as overhead line and cable circuit length, extreme weather, redundancy, accessibility and conditions etc.

However, not all of the data needed to construct such a model is easily available, with much either being very time consuming to source or simply not existing at present, therefore pragmatic compromises must be made.

To then model the cost of interruptions (i.e., by conducting Monte Carlo simulation to represent potential faults, and assigning values to these), the model starts by drawing a number randomly from the modelled distribution of fault frequencies to define the number of faults occurring within that simulated year, where that distribution is inferred from historic data. For each of those faults, the model then randomly samples from the historic fault duration distribution to apply a duration for each fault. The number and duration of faults is then used to determine the associated cost. This process is

[21] In fact, with this distribution, any duration of interruption is possible, but very long durations would be very unlikely.

repeated over a specified (large) number of iterations to create output probability distribution curves for the potential cost of interruptions.

For simplicity, it is assumed that these two distributions are independent - that is, in years where there are more faults, they do not tend to have shorter or longer durations, and vice versa.

3.1.3 Estimating energy not served

For each simulated year (and fault within that year) the MWh of Energy Not Served (ENS) is calculated, as it is the volume of ENS which ultimately drives disutility for customers, with lost load typically valued in terms of £/MWh of ENS.

To do this, we need to understand the ENS associated with different durations of faults, which will change depending on when the fault occurs, due to varying demand patterns over the course of a day and across different seasons. For example, the ENS associated with a four-hour fault in the middle of the night during summertime might be relatively low due to customer demand being low. However, the same four-hour fault occurring during a weekday evening in January could coincide with the highest periods of customer demand, which would therefore result in much higher ENS.

To understand the profile of demand that has been interrupted, historic measured data on power consumption from the relevant substation is used. These datasets should, ideally, include several years of historic demand data, to allow for some representation of unpredictable year-on-year variability in demand patterns, including changes due to weather. However, they should be short enough that they do not include demand profiles from years for which the patterns of consumption are very different to those experienced currently, due to such things as changes in behaviour, improved efficiency of white goods, or changes in the number of customer connections to the network.

For each fault occurrence and fault duration that we simulate, we then randomly sample a sequence of the same length from this historic demand profile. Further, since the historic data includes the time at which faults occur, this can be analysed to establish whether faults typically occur more frequently during certain times of day, or seasons. If such patterns are found, these can be reflected in the sampling by probabilistically weighting the sampling accordingly, e.g., making it more likely that a sequence of demands will be selected that start during a winter evening, if that is found to be a time when faults are more likely to occur. The ENS for any specific fault can then be determined by aggregating the total amount of MWh demand within this sampled sequence.

One drawback to using the total net consumption at the primary transformer is that the net ENS might underestimate gross ENS if there is embedded generation within the primary. A MWh of demand and generation will net off each other while the network is energised. However, during a fault this would mean that there is additional ENS associated with the demand that would otherwise be served by the embedded generator, and there is opportunity cost for the generator when it is not able to export (e.g., lost export or subsidy payments). A more detailed implementation of the methodology could seek to use individual demand and generation customer profiles as the basis of determining gross ENS, rather than net ENS - this could be feasible during the assessment of future implementations of RaaS, since SSEN holds some appropriate data for DERs connected at 11 kV and is likely to be increasingly important for the potential future application of RaaS at higher voltage levels.

It is also relevant and important to distinguish between ENS for domestic vs non-domestic customers, as there is evidence which shows that the VoLL is very different for these two different customer segments. This could also be randomly sampled from a distribution which describes the proportion in % of domestic demand (MWh) associated with different times of day or days of the week, bounded

by any information available on the numbers of domestic and commercial customers connected to the primary substation network. We have implemented such a treatment in our more detailed and realistic examples in Section 3.2.

3.1.4 Valuation of energy not served

Interruptions are often valued using an overall estimated figure for VoLL. A commonly cited source for such a figure is an Ofgem/DECC study[22] from 2013 which determined a VoLL between £6,957 /MWh to £11,820 /MWh for domestic customers, using a willingness-to-accept approach, with estimates that are 3-4 times higher for non-domestic customers.

For the RaaS work, however, we believe that it is not appropriate to assume a fixed cost for each MWh not served.

The approach we have adopted is to consider the disutility of the blackouts the customer in a more sophisticated way, recognising differences in the customer experience for different types of faults. Helpfully, a recent project undertaken by ENWL has explored the variation in VoLL related to relevant factors including the frequency, duration, and scale of faults[23]. This work also provides different values for baseline VoLL, which are higher than those referenced in the aforementioned 2013 study. It is possible that this increase reflects a trend for increasing reliance on electricity.

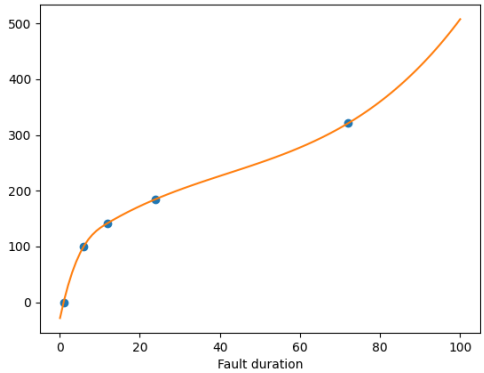
The ENWL report provides outputs in terms of units of "standardised VoLL", along with an approach for converting these to monetary values of £/MWh. We have used this assessment to derive smoothly extrapolated curves which can be used to determine the VoLL for any combination of fault frequency and duration. These curves are provided in Figure 3.2 for domestic customers, together with a heatmap representing the £/MWh VoLL cost for different fault frequencies and durations*.

For each simulated year and each fault within that year, the frequency and duration of each fault is essentially cross-referenced with this heatmap to determine the £/MWh VoLL associated with the fault. The total ENS for the fault is then used to determine the total VoLL for each fault, and the values for each fault are combined to provide the overall values for each simulated year. This is summarised in the equation below, where $VoLL(f, d)$ is the function that maps pairs of fault frequencies and durations to a £/MWh VoLL rate:

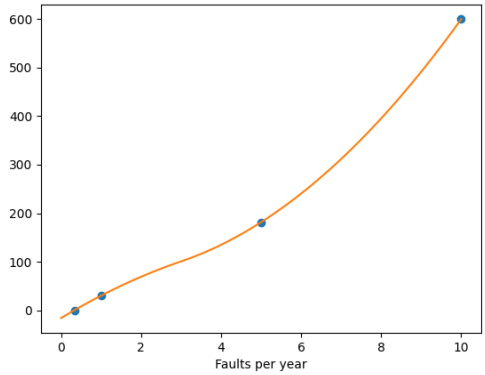
$$Total\ VoLL\ [£\ per\ year] = VoLL(f, d)\left[\frac{£}{MWh}\right] \times ENS\ [MWh\ per\ year]$$

[22] www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gbpdf

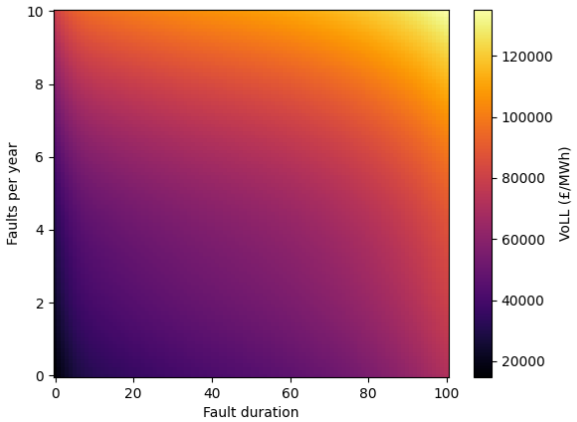
[23] www.enwl.co.uk/globalassets/innovation/enwl021/voll2-ecp-documents/voll-2-customer-survey-report.pdf



(a) standardised VoLL across different fault durations



(b) standardised VoLL across different fault frequencies



(c) VoLL in £/MWh of different fault durations and frequencies

Figure 3.2: VoLL for domestic customers, extrapolated from ENWL VoLL 2 Study

** Note that the VoLL 2 Study includes results for faults that occur "several" times per year, which we have interpreted to be 5 faults per year. We have also assumed a standardised VoLL of 600 for 10 faults per year, as otherwise the extrapolated VoLL for very frequent faults would significantly increase costs.*

3.1.5 Identifying the impact of a RaaS service

To identify the impact, and therefore value, of a RaaS service we pass into the simulation the number of hours by which RaaS would reduce the duration of a fault, where the current default is four hours. The assumption here is that whenever the fault occurs the battery would have a sufficient state of charge to reduce the duration by up to this number of hours, and no more. (This is instead of specifying a MW and MWh for the battery and a state of charge.)

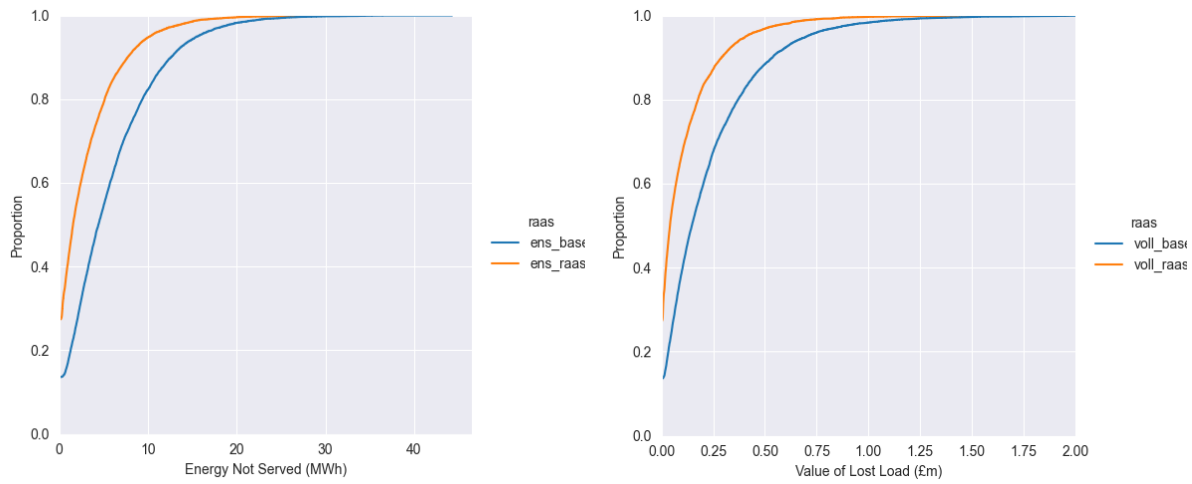
This would be repeated for every fault within each simulated year, and then for a very large number of simulated years. In our initial testing, we have simulated 10,000 years.

Some example results are shown below, for a 4-hour battery using some historic SCADA data. We have assumed that:

- The RaaS service will reduce fault duration by up to 4 hours.

- Faults per year are Poisson distributed, with an average value of 2.
- Fault duration is lognormal distributed, with an average value of 4 hours, a minimum value of 30 minutes, and a most common value of 2 hours. In principle, the probability distributions used would allow fault durations of any length, but these are very, very unlikely to occur.
- A fault disconnects all customers for the full duration.
- For the purposes of illustrating the methodology here, we assume that all of the customers within this notional network are domestic customers, and therefore use only domestic VoLL figures (in contrast, the detailed modelling to provide the results presented within this report includes appropriate mixtures of domestic and commercial customers).

Figure 3.3 shows the results as distributions of both ENS and the total Value of Lost Load. These are presented as empirical cumulative distribution functions (CDFs); the line shows the percentage of simulations (across all 10,000) for which the ENS and the value of lost load are at least as high as the value on the X-axis. This shows that without RaaS, the value of lost load has a 20% chance of being higher than £370k in a year whereas with RaaS, the probability that the value of lost load exceeds this figure is only 6%.



(a) effect of RaaS on ENS **(b) effect of RaaS on total VoLL**

Figure 3.3: Empirical CFDs of demonstration simulation results

Some descriptive statistics of these distributions are provided in Table 3-1. The expected value of interruptions with and without the RaaS service are likely to be the key figures of interest. The difference between these, derived through this probabilistic modelling analysis, provides the service value for RaaS. In this illustrative case, the RaaS service value would be approximately £119k per year. The results by quantile and the standard deviation also demonstrate that, as well as reducing the expected cost of interruptions, RaaS reduces the variation (and, in essence, the uncertainty) in the possible range of interruption costs.

Table 3-1: Table of notional results for methodology demonstration

	Energy Not Served		Value of Lost Load	
	Without RaaS	With RaaS	Without RaaS	With RaaS
Mean	5.66 MWh	2.89 MWh	£223k	£104k
Median	4.41 MWh	1.55 MWh	£147k	£41k
10th Percentile	0 MWh	0 MWh	£0k	£0k
30th Percentile	2.29 MWh	0.35 MWh	£66k	£7k
70th Percentile	7.22 MWh	3.56 MWh	£268k	£113k
90th Percentile	12.6 MWh	7.72 MWh	£537k	£290k
Standard deviation	5.18 MWh	3.71 MWh	£251k	£158k

3.2 Illustrative examples

We have applied the methodology described and illustrated in the preceding Section 3.1 to calculate VoLL costs and RaaS benefits for 24 prospective locations within SHEPD's licence area. These sites represent the subset of those that were shortlisted by the RaaS project team as prospective trial sites[24] for which sufficient data has been provided to demonstrate our analysis. These locations are shown on the map in Figure 3.4. The size of the circle indicates the simulated expected VoLL without RaaS, and the colour indicates the possible benefit of using RaaS to reduce outages by up to 4-hours[25], which could also be taken as the value of the service.

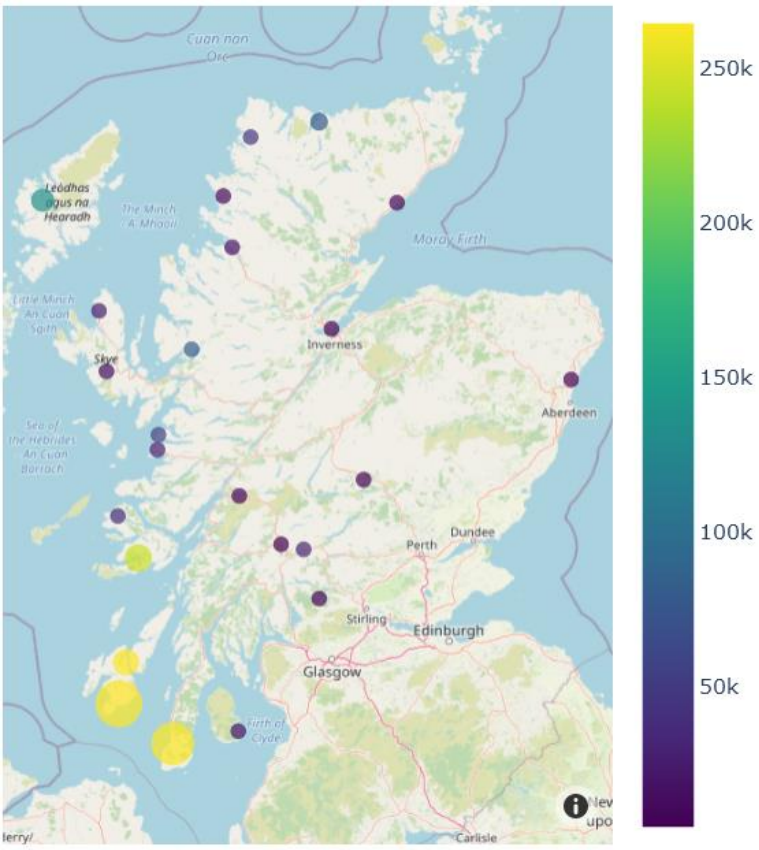


Figure 3.4: Geographic map showing selected prospective RaaS locations

The following subsections provide detail on how these results were produced using the valuation methodology developed for RaaS, including data sources, additional assumptions that were made, and associated results.

3.2.1 Fault duration and frequency data

SSEN provided very detailed fault data for the substations going back to the 2015 reporting year, which runs from April to March. However, as relevant information exists across several different datasets, a preparatory process of combining these historic records was required in order to identify the type, number, and duration, of faults that had affected the primary substations, and discard faults on short branching sections or individual secondary feeders which would not be mitigated by a RaaS scheme. This required manual interpretation across the individual data sets, which is possible but would benefit

[24] This is described in the RaaS 'Site Selection' report (E2a.1), E.ON, February 2021, https://project-raas.co.uk
[25] Note that, 4-hours is not necessarily the optimal service duration for all of these sites, likewise the marginal cost of shorter or longer duration services will need to be considered.

from consideration of revised data collection processes to capture all data relevant to RaaS evaluation in one data set. However, by processing this data, we were able to identify the number of faults in each reporting year, and the duration of the interruption caused by each fault[26], over the 2015 - 2019 reporting years for each of these 24 substations.

Overall, there were 188 faults, with an average interruption duration of around 1 hour and 40 minutes. However, the distribution of durations is highly skewed, with a median duration of around 30 minutes and a most common duration of less than 10 minutes (prior to restoration via network reconfiguration capability where this exists). The distribution of faults per year is similarly skewed, with the most likely outcome being zero faults per year, and some very rare cases of around 10 faults in a single year. Histograms of the number of faults per year and fault durations (in hours) across all 24 sites is shown in Figure 3.5 below.

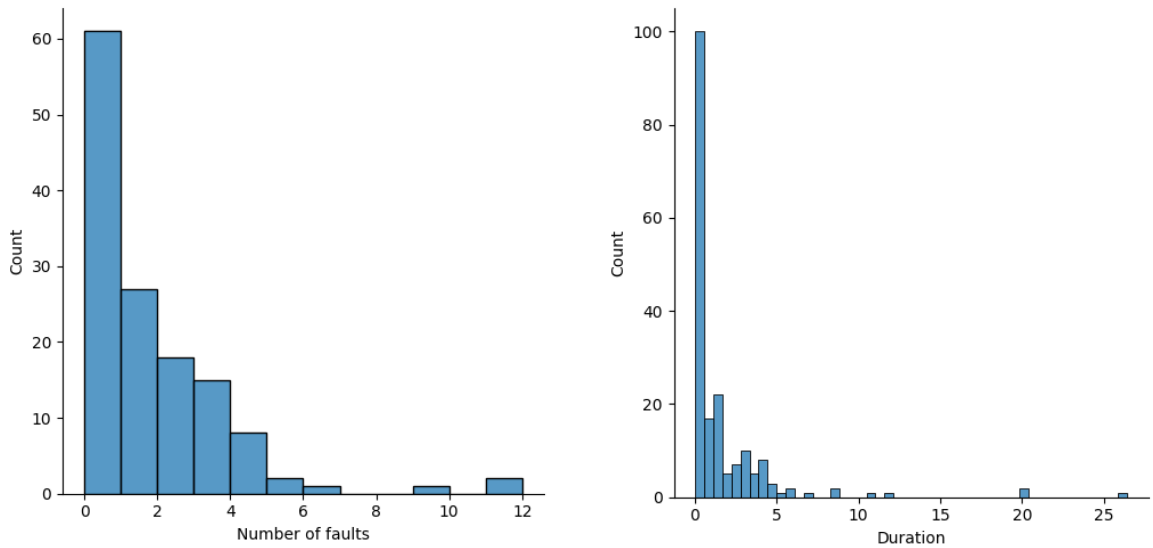


Figure 3.5: Fault frequencies and interruption durations across all prospective RaaS sites

As described in Section 2.2.3.1, the fault characteristics of individual sites appear to vary quite significantly, and it does seem reasonable that the attributes of an individual primary may mean that it typically experiences more or fewer faults than other primaries. However, it is hard to demonstrate this conclusively with only five years of data - as the histograms above show, faults are still relatively unusual, and even for these prospective RaaS sites the most likely outcome is still zero faults in a year.

To overcome this issue, we use a simple hierarchical statistical model which “partially pools” together all of the fault information across all of the sites and uses this to define the individual distribution parameters (number and duration of faults) for each substation. This essentially imposes an assumption that different substations can have different fault characteristics, but that these should nevertheless be reasonably similar. The aim of this is to prevent us from overfitting to outliers within the 5-year data set for any individual substation. This approach builds on the methodology presented in Section 3.1, and can be applied for any analysis that will consider data from more than one prospective RaaS site.

[26] Note that fault durations could actually be much longer than the durations of the interruption caused by faults, as customers will be reconnected based on reconfiguring the network. Within this report, fault duration and interruption duration are used interchangeably.

We then follow the approach described in Section 3.1.2, with a Poisson distribution assumed for the number of faults per year. This distribution takes one parameter, which is the average number of events (in this case faults) per year. We assume that fault duration is distributed following the Weibull distribution family - this family is similar to the lognormal family except that it can have a “heavier tail”, which permits a higher probability of rare events (such as very long fault durations). The Weibull distribution has two parameters: a “scale” and a “shape”.

In this model, we have not included any other factors that could affect fault frequencies and durations, such as weather extremes, circuit lengths, ground conditions, access to site, etc., as at present the amount of data available means that inferences about the exact nature of relationships would be very inconclusive. It is clear, however, that this proposed methodology allows for such factors to be included in the modelling as and when robust data becomes available over future years with consideration to the wider appraisal of RaaS.

To provide validation of the approach, Figure 3.6 and Figure 3.7 below show some examples of modelled versus historic fault durations for Kinloch and Port Ellen, with the y-axis giving the probability that the actual outcome would equal or exceed the value on the x-axis.

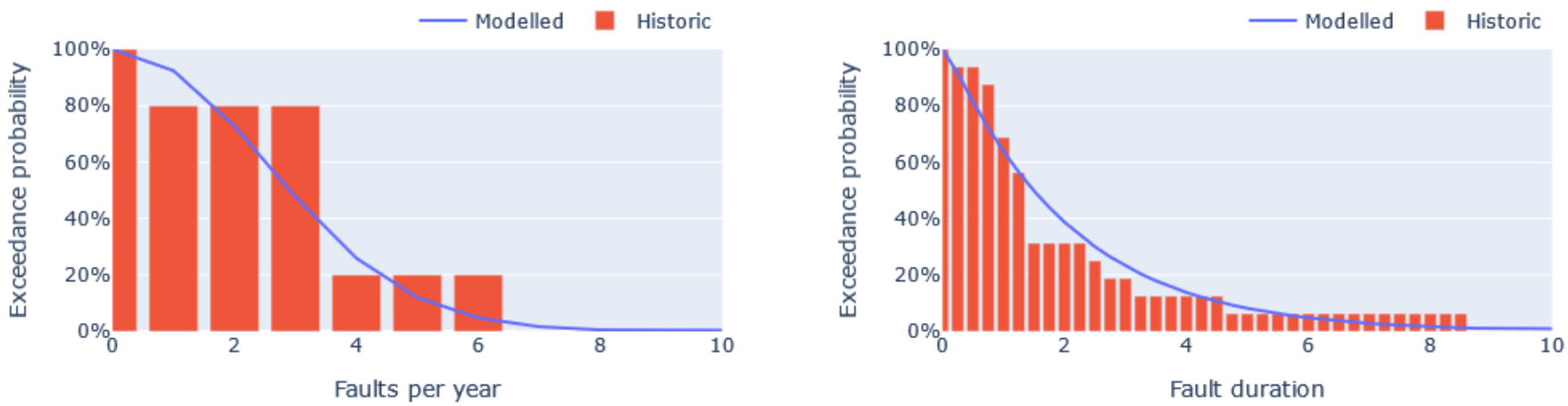


Figure 3.6: Historic and modelled fault frequency and duration for Kinloch

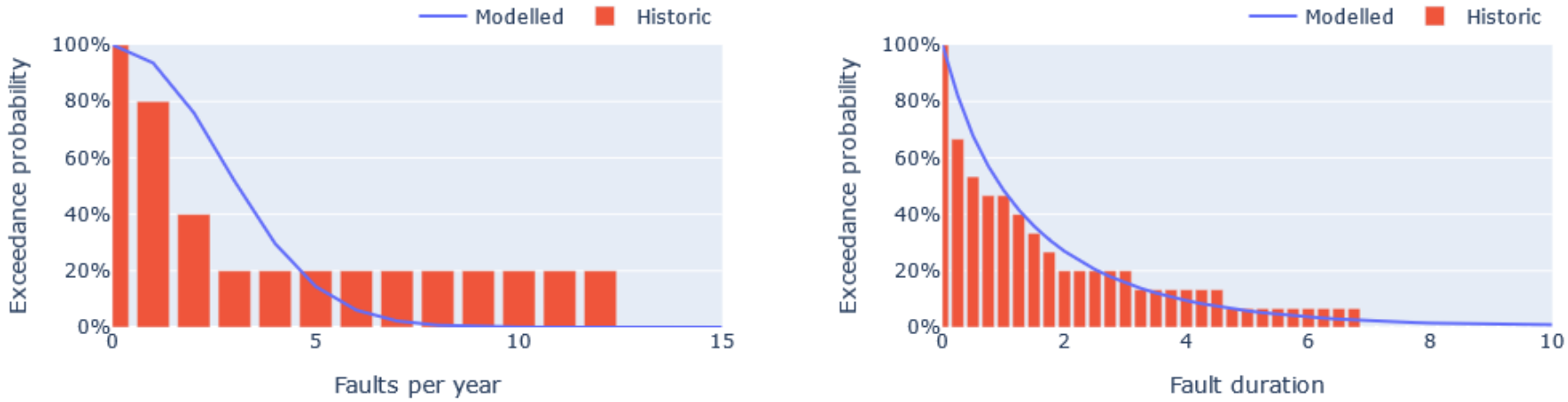


Figure 3.7: Historic and modelled fault frequency and duration for Port Ellen

These results show that there is broad alignment between the historic and modelled distributions, and that the partial pooling approach has resulted in more consistency between the sites, as appropriate for deriving future probability distribution curves.

However, these figures also suggest that there are some features of the historic data that our approach is not capable of modelling very well; in particular, the rare possibility of a very large number of faults happening in a single year. These are largely attributable to more than ten faults occurring in the 2019 reporting year at Port Ellen as shown, and also Port Askaig, both of which are on the island of Islay and are fed by the same 33kV network. Examination of the timing and cause of faults suggests that at least some of these faults are connected: for example, seven of the faults occurred within a space of two months, affected both primaries, and have the same descriptor for cause of the fault (relating to equipment being affected by a private generator or authorised electricity operator).

This suggests that a further refinement to our model may be to allow the rare possibility of a larger number of related faults to occur, in addition to those that occur following the Poisson distribution. For example, we might exclude these related faults from our initial distribution fitting, but then add on a further 1% chance that between 5 and 10 additional faults affect the primary. However, more extensive fault data and input from SSEN engineers would be required to develop a more robust representation of this possible outcome. For this reason, at present this additional level of sophistication would not pragmatically add to the modelling assessment.

3.2.2 Demand data

SSEN provided half-hourly primary substation demand data for each of the sites covering the period from January 1st 2018 to December 31st 2020. We excluded 2020 from our simulations, given the significant impact that COVID has had on behaviour which we would expect to affect the demand data.

For simplicity, we did not attempt to distinguish between normal demand flows, and reverse power flows due to generation export. Therefore, we have just considered the magnitude of the power flow within each half-hour, with the assumption that the entire flow recorded is due to demand (rather than any periods of purely reverse power flow through the substation).

Even with this simplification, there are still periods of poor data quality and missing data. When sampling and validating sequences of demand for determining energy not served, we rejected any sequences in which over 15% of the half-hours had missing data. Missing values below this threshold were dealt with in a straightforward way by filling-in with mean-interpolation figures.

3.2.3 Simulation approach

Once the data was prepared, simulations were carried out using the approach detailed in Section 3.1:

- Simulate a number of faults.
- Simulate a duration for each fault.
- Randomly select a half-hourly sequence of demands for each duration.
- Identify the reduction in fault duration and ENS associated with various sizes of RaaS service.
- Transform ENS to VoLL using the figures contained within ENWL's VoLL 2 study.

We also used the numbers of domestic and non-domestic customers on each primary to determine the proportion of the primary demand attributable to domestic and non-domestic customers respectively. This is important as ENWL's VoLL 2 research suggests that non-domestic VoLL is much higher than domestic VoLL, in some cases by a factor of 2-3. We also determined this proportion in a

different way, based on some average domestic and SME profiles which we derived from NPg's Customer Led Network Revolution[27] project. These profiles suggest that SME customers tend to have higher demands than domestic customers, so splitting the primary demand based purely on customer counts would underestimate the proportion of demand attributable to non-domestic customers. This gave us indicative most likely, minimum, and maximum non-domestic proportions of demand, which we sampled from for each simulation.

Lastly, we used the customer numbers at each primary, the number of simulated faults per year, and the fault durations, to determine volumes of Customer Interruptions and Customer Minutes Lost for each simulation. This is a separate, but relevant, assessment alongside the consideration of VoLL, as IIS figures are directly related to the RIIO price control mechanism for DNOs. These were monetised at a rate of CI = £12.46 per Customer Interruption, and £18.20 per 60 Customer Minutes Lost, sourced from the SSEN/Frontier Economics 2020 study into the optionality value of flexibility[28,29].

We carried out 50,000 simulations for each substation and considered RaaS service durations of 1 to 6 hours.

3.2.4 Results

This section presents detailed results for one substation - Kinloch - and then summary results across all 24 substations.

Figure 3.8 below show the probability of different levels of IIS cost associated with Kinloch in the situation where no action is taken to improve resilience, and then Figure 3.9 shows the probability that different levels of RaaS service (i.e., number of hours that RaaS will provide support for) will achieve different reductions in IIS cost. As with the previous fault frequency and duration distributions, the y-axis gives the probability that the value on the x-axis will be equalled or exceeded. The horizontal dashed lines show the expected (average) values.

It is worth noting the slightly unusual shape of these figures for very low values of IIS cost. These tell us that there is a non-zero chance that the IIS cost will be £0. In fact, this is just the probability of having zero faults in a year, which for Kinloch is modelled as ~8%. We can also see that the curve is approximately flat between £0 and around £7,900. This is because of the effect of the structure of the IIS mechanism on the cost function - if any faults resulting in outages longer than 3 minutes occur, then the minimum IIS impact will comprise 589 CIs (the number of customers at Kinloch) and 1767 CMLs (3 minutes for 589 customers). With the values stated previously this results in a penalty cost of approximately £7,900.

[27] www.networkrevolution.co.uk
[28] http://news.ssen.co.uk/news/all-articles/2020/july/ssen-announces-a-new-cost-effective-approach-to-delivering-a-smart,-low-carbon-energy-system
[29] Note that these values apply to SEPD's licence area, and though CI and CML rates are different for different licence areas, for the purposes of illustrating the methodology these values are similar enough to SHEPD rates.

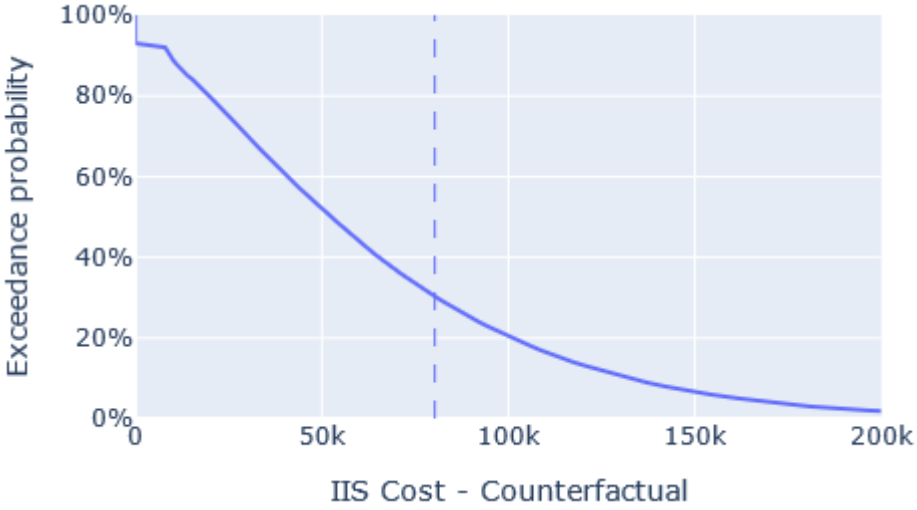


Figure 3.8: Modelled IIS cost for Kinloch

The average IIS cost across all the simulations for Kinloch is around £80,000, although there is only a 1/3 chance that this level of cost is reached in any given year. This is because of the skew in the fault distributions. For comparison, the actual historical IIS cost by reporting year associated with the fault data shared by SSEN is shown in the table below.

Table 3-2: Historical IIS costs for Kinloch

Reporting year	IIS cost (£)
2015	£0
2016	£53,865
2017	£65,003
2018	£33,331
2019	£240,560
Average	**£78,552**

The distribution of RaaS benefits (i.e., cost reductions) show fairly similar patterns. There is a similar "step" like behaviour, which can be explained by further jumps in CIs & CML as RaaS is able to completely prevent further faults from occurring. One key observation is that - much like the actual faults and the resulting costs - there is a chance that in any particular year, the RaaS service could provide no benefit to SSEN and its customers. However, in the long run, the benefit of the service should converge to the expected value derived from this approach to modelling.

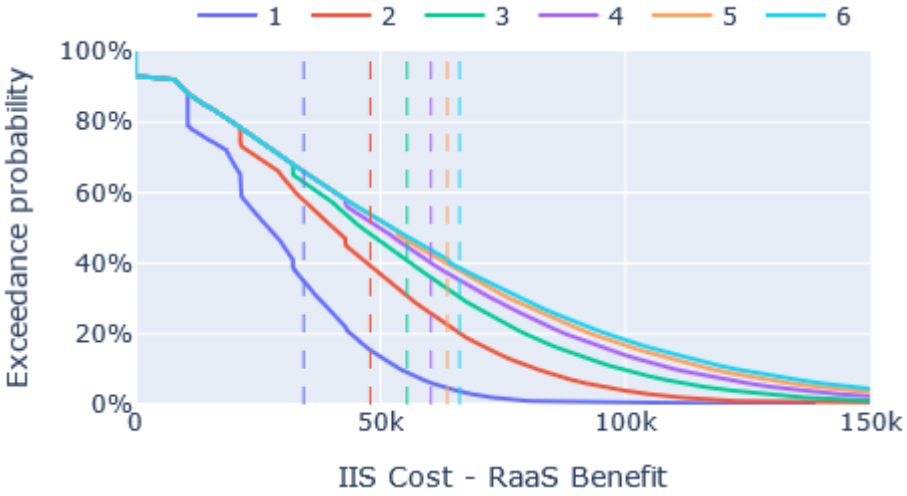


Figure 3.9: Modelled IIS benefit of RaaS for Kinloch

Figure 3.9 also shows that higher duration services do have larger expected benefits, but that this increase in benefit diminishes quite sharply beyond a certain duration of service.

To then consider the benefits associated with Value of Lost Load, Figure 3.10 presents the probability of different VoLL impacts on customers associated with Kinloch in the situation where no action is taken to improve resilience. The expected VoLL figure for Kinloch is £333k, prior to introducing any RaaS service to mitigate interruptions.

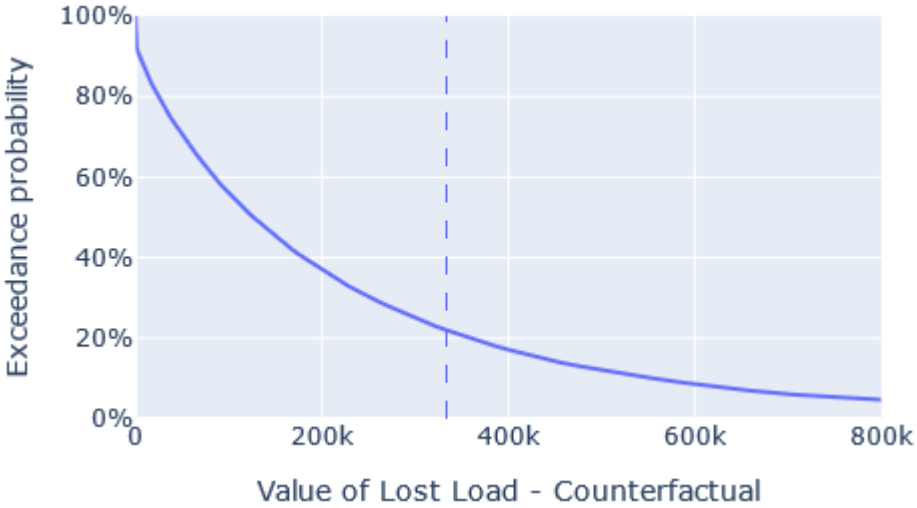


Figure 3.10: Modelled VoLL cost for Kinloch

Figure 3.11 then shows the probability that different levels of RaaS service (i.e., number of hours that RaaS will provide support for) will achieve different benefits for customers with regard to VoLL.

Figure 3.11: Modelled VoLL benefit of RaaS for Kinloch

The results follow similar patterns to the IIS assessment, with two key exceptions:

- There are no discrete jumps due to the number of faults occurring, since cost is ultimately driven by energy not served (which is a continuous variable) rather than fault numbers (which are discrete).
- The values are, in general, much higher than the IIS cost values. This is due to the underlying VoLL figures from the ENWL study being higher than previous estimates (which we understand have historically been used to help set CI & CML levels). A further effect here relates to the fact that the VoLL 2 study demonstrated that VoLL increases non-linearly with fault frequency and duration.

This second point is illustrated in Figure 3.12, which plots the expected £ benefit in terms of both IIS and VoLL against different service durations, showing the notable difference between IIS and VoLL benefits. This also emphasises the diminishing marginal benefits of longer RaaS service durations, with the value increasingly much less sharply as the duration is extended.

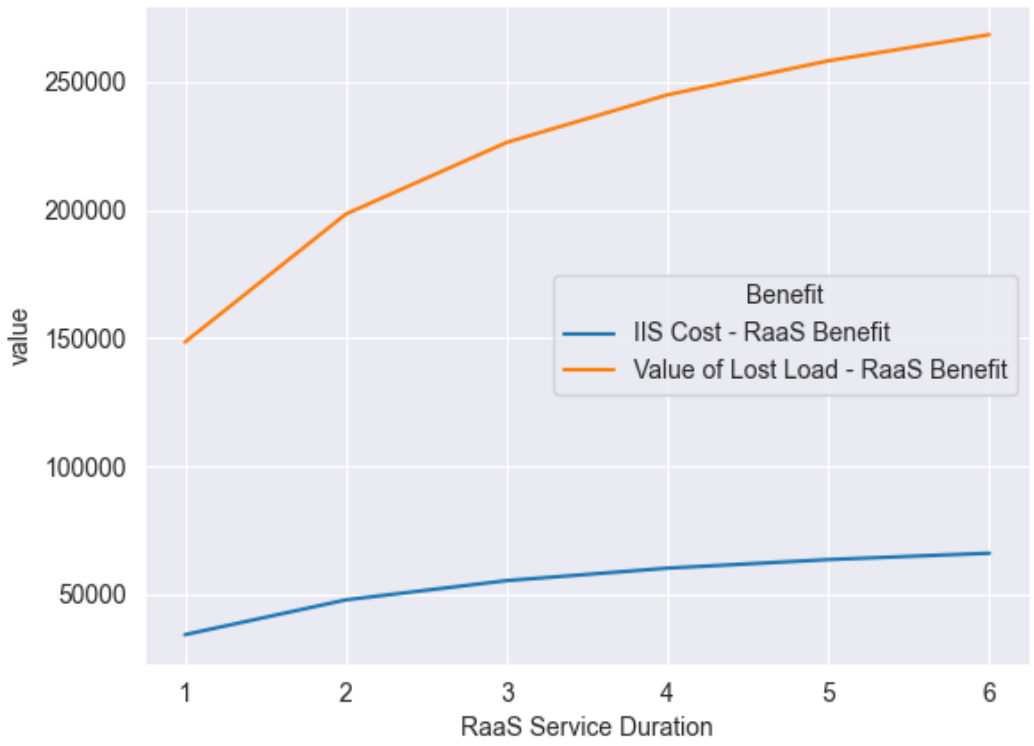


Figure 3.12: Relationship between expected RaaS benefit and service duration for Kinloch

Figure 3.13 and Figure 3.14 below then provide summaries of the expected costs and benefits across all 24 substations, further illustrating the difference between using IIS costs and VoLL. This difference is particularly pronounced for West Parkfergus. This substation serves a single, very large non-domestic customer, therefore, CI & CML volumes for interruptions at this site are very low. In contrast, since their demand is high, then ENS can be very high, with the VoLL for non-domestic customers applied to this figure also being high.

These figures illustrate the variability in benefits between different sites, with some indicating expected VoLL benefits of almost £1m, while others imply expected benefits of less than £10,000.

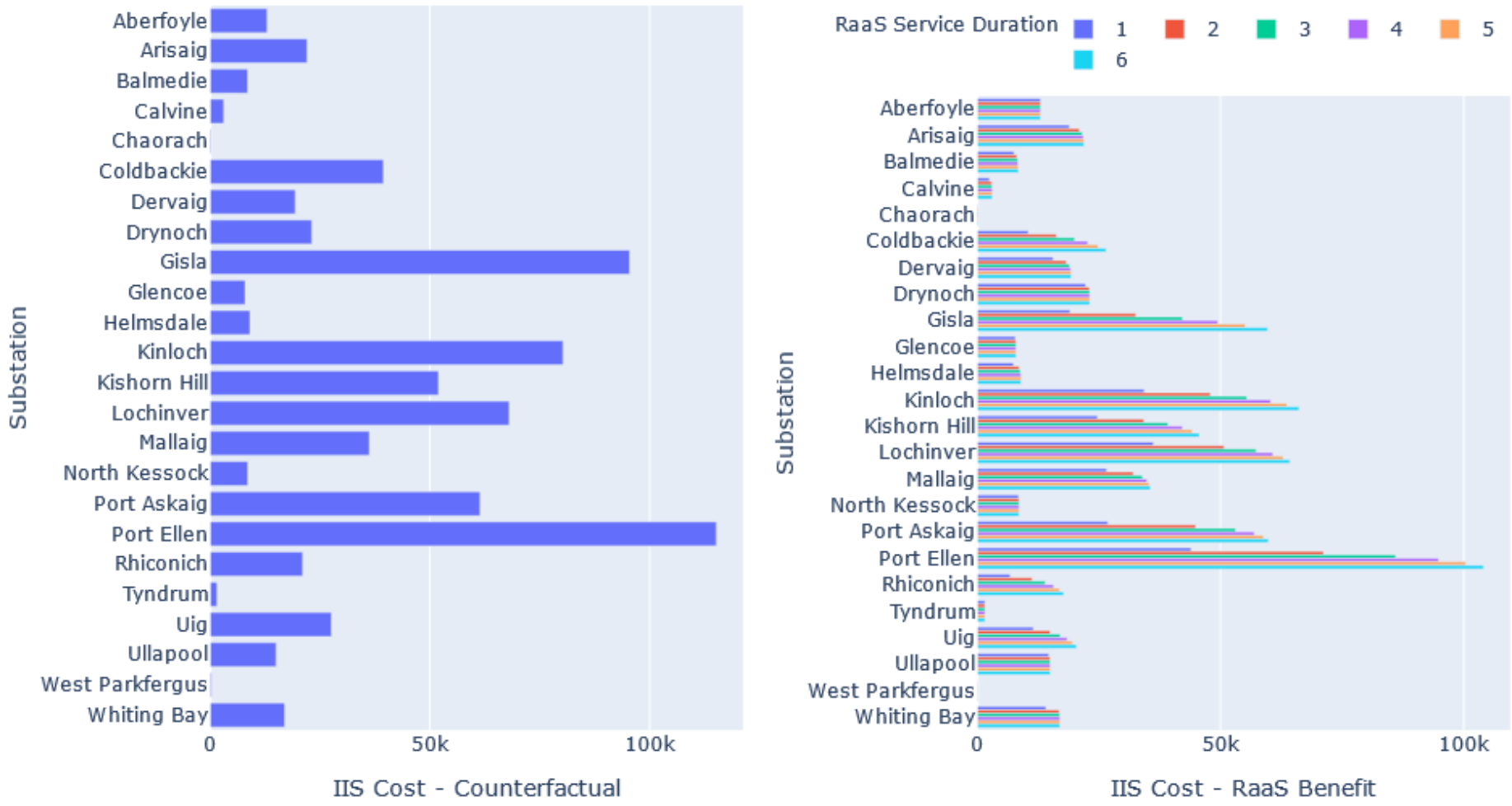


Figure 3.13: Modelled IIS cost and benefit of RaaS for the 24 sites assessed

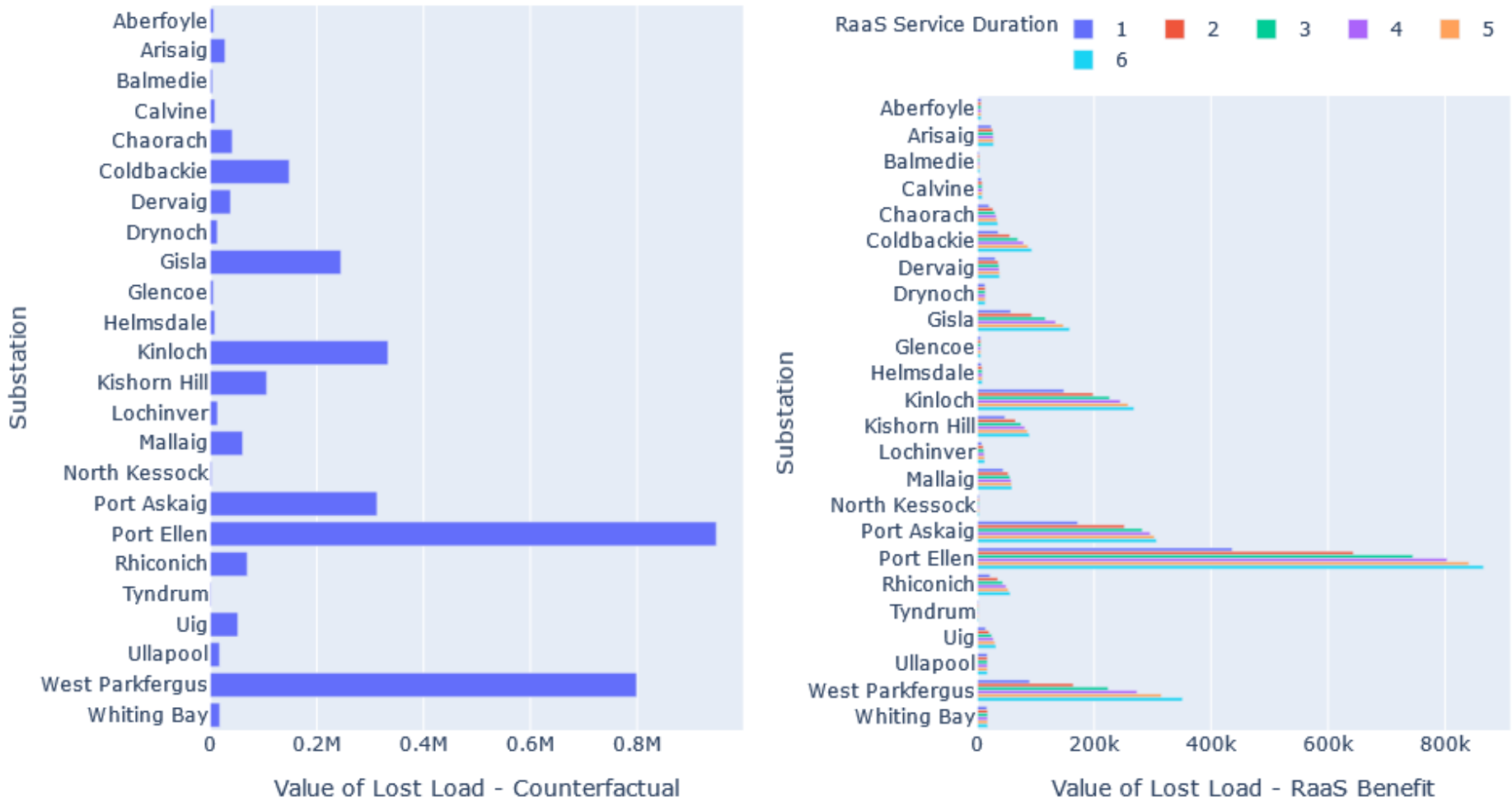


Figure 3.14: Modelled VoLL cost and benefit of RaaS for the 24 sites assessed

3.3 Implications for the project

It is important to bear in mind that the results presented above, while based on real SSEN data, are still considered to be illustrative. Further refinement of inputs, wider scrutiny of assumptions, and greater development of the associated process would be required before adopting this approach as part of the valuation for RaaS services.

Nevertheless, these illustrative results do suggest that RaaS could be beneficial for many substations within SSEN's network. Figure 3.15 and Figure 3.16 below show the number of substations (out of the 24 sites assessed) where the expected benefit of RaaS is equal to or higher than threshold values for IIS and VoLL respectively, where those values are shown on the x-axis. Analysis of all SHEPD and SEPD primary substations may reveal further sites where RaaS may be of benefit.

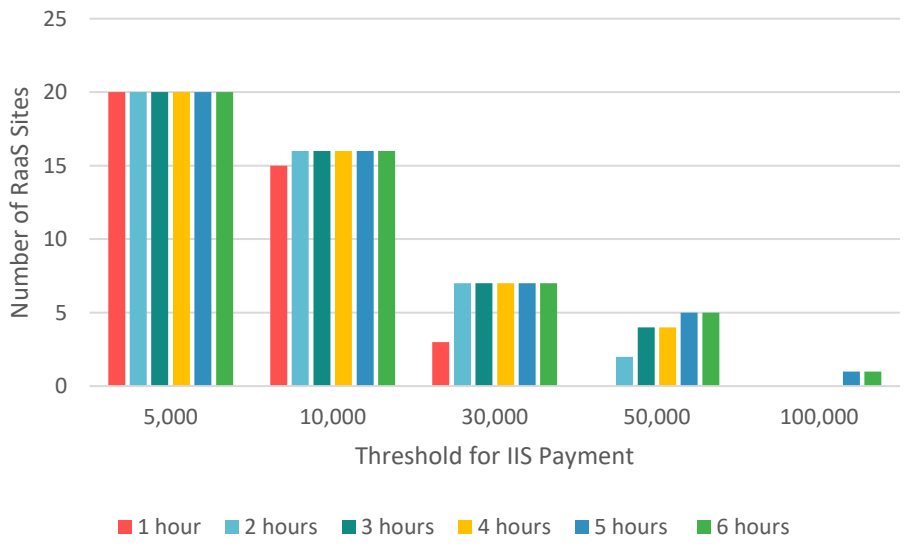


Figure 3.15: Number of assessed SHEPD sites where IIS benefits exceed threshold

Figure 3.16: Number of assessed SHEPD sites where VoLL benefits exceed threshold

To consider the potential overall financial viability of applying RaaS at these sites, however, information on the associated fee requirements for a RaaS Service Provider at each site would be required, which would be evaluated based on their capability to participate in other flexibility markets to stack revenues, and their associated decisions regarding sizing the battery for a specific location.

Taking examples from the illustrative assessment provided above, if a 1-hour RaaS service can be provided for £5,000 per year or less, then there are 20/24 sites where the expected IIS benefit justifies the cost of the service. But, if a 1-hour service costs £30,000, then there are only three sites where it is justified (nine if valuing this using VoLL). If a 4-hour service costs somewhere in the region of £30,000 to £50,000 to provide then it might only be justified on 1/3 to half of the sites if using VoLL, and even fewer if using IIS. The number of sites where a 4-hour service could be justified could increase in the future if the costs that drive the provision of the service decrease (such as battery costs), or if DNO demand forecasting capabilities develop to allow more real-time definition of forward RaaS service requirements, allowing a greater proportion of the battery capacity to be available for participation in other flexibility services markets.

The illustrative results show that the sites assessed show a very wide range of benefits. This includes:

- Variability between sites, with some having £100,000s of expected benefits, and others only having £1,000s of benefits.
- High variability for a site from one-year to the next, with a benefit of £0 over the course of a year always a possibility
- Significant differences between the benefits that arise when using IIS costs versus those based on the Value of Lost Load.

It is also clear, as shown in Figure 3.12, that the marginal benefit of significantly longer duration services is quite low in many cases. Rather, a significant benefit can be achieved from just a 1-hour or 2-hour battery. This finding is of relevance to the project as a DNO may see value in tendering for shorter duration services, or indeed for a range of durations of RaaS service, to then evaluate which of the fee levels offered provides the most cost-effective solution for improving service to customers.

Further, from this analysis it seems that the highest benefit is at those sites which experience very frequent faults, but where those faults tend to be shorter. This reflects the fact that a higher probability of faults occurring is an important factor in establishing the case for having a RaaS service available year-round to address those faults year-round, though again the economics of this are very much dependent on the other services open to the RaaS Service Provider for revenue stacking. As the analysis presented above considers fixed durations of RaaS service (i.e., 1 hr, 2 hr, 4 hr), the requirement to have the RaaS service always available (via reserved capacity in the battery) and the economics associated with revenue stacking (using the remaining 'headroom' capacity) illustrate the value of the project's wider work to consider a range of RaaS 'product design scenarios' which specify the energy requirements for a RaaS service at different levels of granularity/complexity (as described in the RaaS 'Flexibility Scenarios' report[30]). When assessing RaaS requirements for a site, the inclusion of enhanced detail linked to expected demand patterns would support the provision of a RaaS service capable of covering a given duration of outage, whilst allowing a greater proportion of the battery capacity to be available for optimisation in other flexibility markets, thereby improving the business case for both the DNO and RaaS Service Provider.

[30] RaaS 'Flexibility Scenarios' report (E4.1), E.ON, November 2020, https://project-raas.co.uk

One additional point for consideration is the possible trend for interruptions to increase in frequency in the future due to deteriorating asset condition. Figure 3.17 below shows the total IIS payment for SHEPD where the cause was recorded as either "Deterioration due to Aging or Wear (excluding corrosion)" or "Corrosion". The apparent trend for asset condition to lead to an increase in interruption costs is supported by anecdotal information based on experience, although we must be cautious about concluding anything too strong based on only five years of data. Another reason why interruptions may increase in the future is an increase in the frequency and severity of extreme weather events associated with climate change, for which there is already strong evidence.

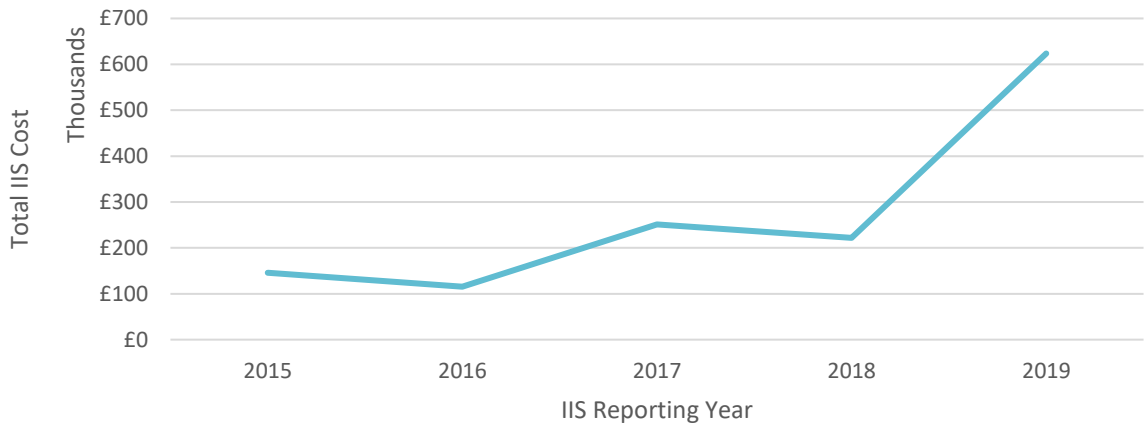


Figure 3.17: Historic IIS cost with causes "Deterioration due to Aging or Wear (excluding corrosion)" and "Corrosion"

For context, the average net present value of benefit within the original NIC cost benefit analysis was £1.3m per site over the 27 years between 2023 and 2050. This corresponds to an annual benefit of around £80,000 per year over 27 years. The illustrative results here make it seem unlikely that such a high-level benefit of could be realised for hundreds of sites throughout GB if valuing interruptions through IIS. This seems more realistic if using VoLL to value benefits, particularly if VoLL grows in the future with the electrification of heat and transport.

It may also be possible that other types of substations with less frequent interruptions could yield much lower benefits, but in much higher volumes. For example, rather than 100s of sites with benefits of ~£80,000, it may be possible to get ~£8,000 benefit at 1,000s of sites or ~£800 of benefit at 100,000s of sites. This might involve using RaaS in different ways, e.g., at lower voltage levels to respond to faults, or during planned maintenance such that it only needs to active for a few weeks per year using existing DERs.

It is also possible that other stacked services, such as Short-Term Operating Reserve, could place similar state-of-charge requirements on the headroom battery capacity (available beyond the capacity to be reserved for RaaS) which might require the battery to be charged very frequently, with discharging only required some of the time. With consideration to this, it may be more cost-effective to provide several services that could be provided by available battery capacity rather than individual services at distinct points in time, however this is a decision for a potential RaaS Service Provider.

3.4 Implications for the GB business case

3.4.1 GB-level business case sensitivities

Based on the findings of the individual substation valuations presented above, and the discussion in Section 2.2.3, we have undertaken some sensitivity analysis varying some of the assumptions and parameters included in the original GB assessment undertaken for the NIC submission. We have explored two key sensitivities, separately and in combination:

- Exploring different MWh per MW requirements for batteries, based on different durations of RaaS service.
- Varying the number of sites where RaaS is appropriate as an alternative for improving resilience, via the assumed fixed cost of providing a completely reliable service.

It is important to restate that this is not a complete, exhaustive update of the original GB-level CBA as this would require an update to two key inputs which are not yet available:

- An indication of the required service fee for different levels of service (in terms of duration and reliability), recognising that this is likely to be different for each individual RaaS site.
- A more detailed assessment of the number of prospective sites across other GB DNO regions.

In addition, the gaps and limitations of the original GB CBA approach that are discussed at length in Section 2.2.3 still apply.

3.4.1.1 Different durations of RaaS service

Considering the original assumptions about fee requirements (which are strongly influenced by £/MWh battery costs - completely so for a 100% available service), reducing the RaaS service duration from six hours to four hours would in turn reduce the cost of the service. This increases the benefits associated with the original GB-level CBA, from £146m to £163m, with RaaS now selected on all but one of the 114 candidate sites in our model.

A further reduction in service duration results in less increase in benefit compared to the six-hour service, with a two-hour battery increasing the benefits to £156m. This is somewhat counterintuitive but is linked to the fact that the requirement for the battery size also decreases in the baseline option where there is no RaaS service (and resilience is provided by DNO owned energy resources that are only used for resilience), which means that, while the cost of the RaaS service options decrease, the costs that they are being compared to also decrease in many cases. As discussed in Section 2.2.3, the validity of this finding depends on how realistic it would be for a DNO to buy its own battery to prevent interruptions. Given that a DNO is not able to participate in other flexibility markets to stack revenues, this may not be considered a cost-effective solution.

The GB-level benefits for different service durations are summarised in Table 3-3.

Table 3-3: GB-level benefits for different service durations

Service	GB-level benefit
Six-hour (original assumptions)	£146m
Four-hour	£163m
Two-hour	£156m

3.4.1.2 Fewer prospective RaaS sites

We have also examined how the assessed GB-level benefits change if RaaS proves to be viable on fewer sites than originally assumed. To do this, we have explored the impact of only allowing RaaS to be available on the sites which have the highest overall benefit. For example, if RaaS only proves to be viable on the ten sites which have the highest overall level of benefit, then this would result in an overall GB level benefit of £26m. Although this is much less than the headline figure used within the NIC CBA, it is still greater than the total funding required for the NIC project, thereby reinforcing the justification for the project. The results of this sensitivity are summarised in Table 3-4. (Note that this is based on the four-hour service duration, rather than the original six-hour duration.)

Table 3-4: GB level benefit with different numbers of sites

Number of sites	GB-level benefit	Average benefit
10 sites	£26m	£2.6m
25 sites	£57m	£2.3m
50 sites	£102m	£2.0m
75 sites	£135m	£1.8m
113 sites	£163m	£1.4m

4 The economics of RaaS payments

The RaaS valuation methodology described in the previous section provides a practical and robust means to determine the expected value of the service. The calculation of this value is a key component in deciding how much a prospective RaaS Service Provider (RSP) should be paid for their service at a particular location, essentially providing an upper limit for the payment. The rather complex question of the ideal structure for RSP payments, including the required parameter values for a specific instance of a generalised structure, is the topic of this section of the report. The topic is, in fact, so complex that it has proved impossible to find a definitive solution representing the ideal payment that should be offered, even when the potential value of RaaS – as a function of the commissioned level of service – is accurately known.

4.1 Context

The proposed RaaS concept is that the battery capacity (i.e., number of exportable MWh stored) required to provide a RaaS response in the event of disconnection from the wider network should be maintained at all times. This 'reserved capacity' would be determined based on the duration of service sought by the DNO and expected levels of demand over time. The RSP is then free to use any remaining 'headroom' capacity available to participate in other markets and access additional revenue streams[31].

It is expected that the DNO would calculate the MWh value that would be needed to meet, e.g., 4-hours' worth of demand in 90% of cases (statistically, in the long-run), and to contract for that level of MWh (and MW) from the RSPs. The requirement for MW export capacity is not discussed in this report, which is acceptable as long as it is assumed that this capacity is high enough to ensure that is does not restrict the battery's ability to fully meet demand at any point in time, beyond the restrictions imposed by how much energy remains. This approach of specifying a required MWh reserved capacity will, of course, be more efficient if the figure varies by time of year and/or time of day. However, as discussed in Section 5, finer granularity in service level specification would necessitate more complex forecasting analysis. In the event that the battery provided the contracted amount of energy, but that following a loss of supply event this wasn't sufficient to cover the duration intended by the DNO, the RSP would not be penalised.

However, it is recognised that the RaaS service would only be call upon rarely, and as one among several flexibility products offering payment for the provision of services, it should be acknowledged that it may not be cost effective for an RSP to always maintain the full contracted MWh capacity for RaaS at all times, and that a lower level of availability might be more pragmatic.

Where permitted under a RaaS contract, this type of deliberate 'double booking' of storage capacity could be expected to lead to a reduction in RaaS payment for the RSP, since the proposed technical solution would monitor the state-of-charge of the battery with this information available to both the RSP and the DNO. Further, it seems reasonable, and possibly essential, to structure the payments and penalties awarded to the RSPs in such a way that the penalty for allowing the energy available to dip below the contracted amount should be considerably more severe if this happens to coincide with a grid-disconnection event.

Any dipping below the contracted energy capacity by an RSP can therefore be considered a 'gamble' that the battery will not be called upon to provide the RaaS service at that time. Some degree of such

[31] The capability to participate in other flexibility markets is not open to DNO owned and operated storage due to regulatory licence conditions associated with generation activities

gambling may well be economically rational for the RSP operating in a market characterised by stacked services – although the maximum extent of the gambling that can be considered rational/ advantageous to the RSP is highly dependent on the payment schemes for each service.

This section of the report therefore includes an exploration of how severely an RSP should be penalised for less than full compliance with the RaaS requirements. For example, the DNO may decide that one single instance of the RSP not storing the contracted amount of energy is sufficient to drastically reduce the availability payment. However, as that approach might be viewed by potential RSPs as too draconian to attract participation in RaaS, a DNO may choose to assess, e.g., average availability.

With each of these considerations, the question of what is the best payment structure to agree with a potential RSP, given the fact that there is inevitably some uncertainty about their ability and/or willingness to provide the full contracted service at all times, is a challenging one. For example:

- If there is a constant probability of 10% that an RSP will not be able to provide the contracted service at any given point in time, should this provider simply receive a 10% smaller payment than a provider who always delivers with complete certainty? Should the penalty be a fixed amount per MWh lacking? Should the penalisation in fact be more severe than that?
- Should a certain degree of gambling be tolerated, perhaps with mild disincentives, or should it all be seen as gamification, to be punished severely (in terms of reduced payments)? Or, at the other extreme, should the penalty only be applied at all if the reduced energy capacity actually leads to an insufficient response during a disconnection incident? To what extent should it depend on the degree to which the required energy wasn't available? In other words, what is the correct balance here between incentivising the providers to remain sufficiently full and not making the agreement too draconian to be attractive to potential RSP companies?
- If there are no disconnection events, what should the payment be? More generally, to what extent should an RSP's revenue be stabilised against differences in the projected and actual number of disconnection events?

In the following subsections, we explore these questions in detail by presenting several candidate payment structures and framing them as special cases of a completely general formulation for that structure. For convenience, we assume that 4 hours is the desired duration of service, which means that there is limited marginal benefit from being available for longer but being available for shorter durations may still provide significant benefit. Other durations may also be appropriate for a given site, but using an assumption of 4 hours does not affect the general analysis of payment structures, as the principles are independent of this value.

4.2 Basic principles for the payment structure

The following principles are proposed as fundamental in guiding the development of an optimal payment structure for RaaS:

- The DNO should not expect to pay more for the service than the expected benefit in terms of reducing interruptions, as calculated in Section 3 of this report. In other words, the expected total payment from the DNO to the RSP should not exceed the expected reduction in the cost of interruptions achieved by applying the RaaS solution.
    - Note that the term 'expected' here refers to the probabilistically weighted mean across all possible outcomes, both for the penalty reductions achieved by the RaaS solution, and

the payments the DNO would have to make according to the proposed payment structure. Clearly, satisfying this condition does not mean that the RaaS solution is guaranteed to save more than it costs on every individual year, or even over a run of 10 years – although they should match quite closely for the latter. Rather, adopting this principle means that the DNO is either risk averse or risk neutral, in the case that the expected values match.

- Imposing a stronger constraint is possible: that the payment made to a service provider should never exceed the economic benefit for a particular year (or season), regardless of the interruption event outcomes, however this is probably not an attractive proposal to a potential RSP, who would prefer more stability and predictability in the payments they may expect to receive over the contract duration.
- Options for ensuring some degree of stability could include some form of guaranteed minimum payment for the RSP. Similarly, from the network perspective a DNO may wish to either cap the maximum payments made, or at least offer a fee structure that reduces the probability of very large payments.

- The expected total reward given to the RSP should be positive, and a DNO should not design a fee structure where a provider would expect to lose money on average (although it may be permissible that a provider could lose money in a specific year if there are many interruptions at times where they do not have their contracted state of charge available).
- In principle (mathematically speaking), the design of the fee structure should also consider the costs to the provider for offering the service, either in terms of the cost of the battery or the opportunity cost of not being able to participate in other flexibility market services, or both. We do not explicitly consider this here, however as described above, maximising the overall expected reward should make it more likely for this to be the case. If the expected reward for a fair valued RaaS service does not exceed the cost of providing that service then, the RaaS solution is unlikely to be suitable for the site in question.
- Specific constraints should be imposed on individual elements of the payment structure. For example, the total penalty (i.e., reduction in payment) associated with an RSP failing to provide the full contracted service during interruption can equal the cost (IIS or VoLL) of the consequent interruption, or be less than that cost, but should not exceed it. Similarly, availability and utilisation payments should always be a positive figure. Availability payments for a specific period should certainly be zero if there was no available energy in the battery during that period, potentially likewise for less extreme breaches of the RaaS agreement. Utilisation payments should clearly be zero if no interruption events were avoided or shortened, but again may be zero for less extreme breaches.
- The payment structure should ensure sufficient incentive for the RSPs to always provide the contracted service, without being too draconian to the point that not many potential providers are interested in offering the service. There should be no way, regardless of the interruption event outcome, for a provider to earn a larger payment for making less of an effort to remain sufficiently full. However, unless the RSP's historical state of charge is recorded and shared with the DNO, it is impossible to guarantee that less effort to comply is necessarily translated into a reduced payment.
- Finally, a slightly controversial point: since it might be logical, in some circumstances, for an RSP to gamble by committing to provide more than one low frequency and unpredictable

service in parallel, it might make sense for the payment structure to explicitly accommodate this.

- For example, if a provider is open about doing this, but turns out to provide the full required service during a number of disconnection events, perhaps they should be paid as much as a provider that is 100% dedicated to RaaS. However, they should receive a reduced payment in the event of no interruptions, and possibly even for a smaller than average number of events. This could possibly be balanced out by less severe penalties for not providing the service, which could take the form of being penalised in the same way as a dedicated provider, but with a proportional (e.g., 10%) reduction in each penalty.
- Alternatively, the provider may have a 'failure allowance' for which it is only lightly penalised, but with full penalties applied for any failures to provide adequate service thereafter. The best approach here remains an open question.

4.3 Basic components of the payment structure

This section provides details of the proposed fundamental components of a payment structure. The most general formulation allows for the most complex structure possible. The potential, indeed, very likely, simplifications include setting several of the components of the most general payment structure to zero. Some of the simplest yet viable potential solutions comprise only one or two of the components. It must be acknowledged that a seemingly optimal solution identified from this completely general structure might not represent a structure, or indeed 'way of thinking' that is familiar to the potential RSPs and may therefore not be an option in practice. Nonetheless, identifying what appears to be an ideal solution, or possibly several solutions that are clearly very good but not proven to be optimal, is surely very useful for the DNO as they determine the best of a number of options acceptable to an RSP.

The fundamental components of the payment structure, discussed in their individual subsections below, are summarised in Figure 4.1.

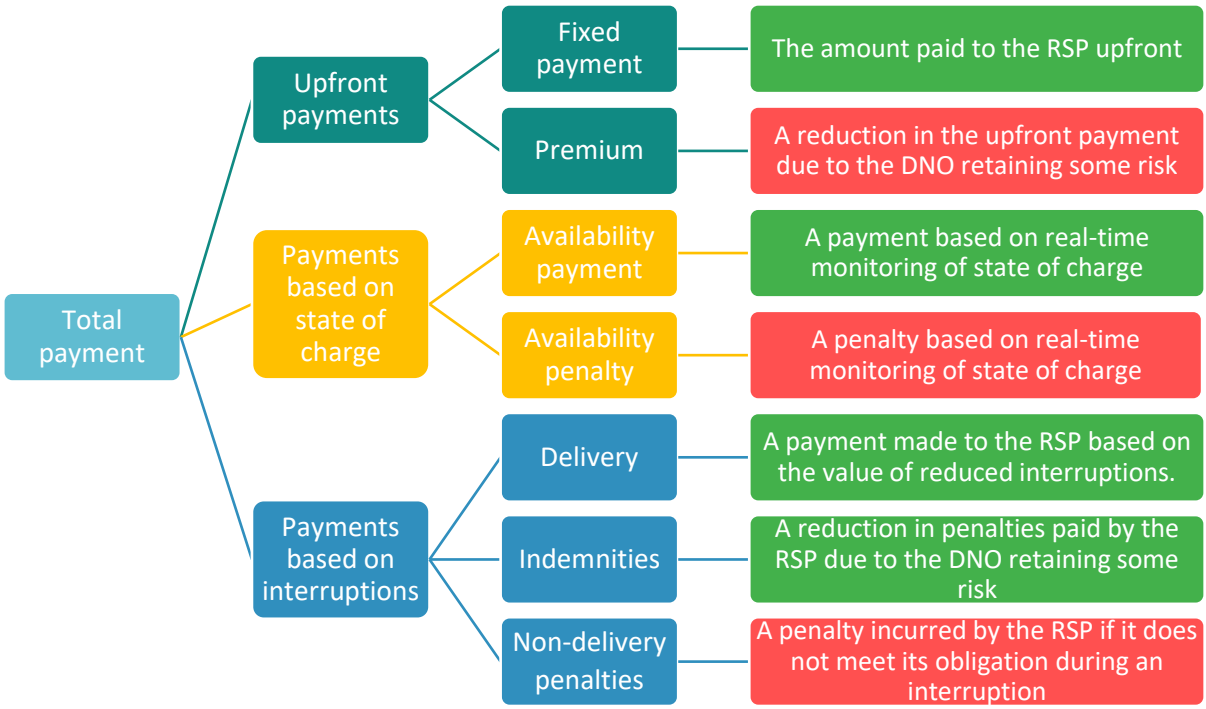


Figure 4.1: Structure of possible payment components

Any payment structure consists of any single one, any pair, or all of the following components:

- Upfront payments
- Payments based on the state of charge at any point in time
- Payments based on actual responses to interruptions

There is potential for all three of these elements to both increase or decrease the payment received by the RSP. The ultimate combination of these elements needs to be chosen carefully to ensure it adheres with the principles set out in the Section 4.2. The following sections discuss the key aspects of these components.

4.3.1 Fixed payment

A fixed payment is clearly the simplest possible component of the payment structure and could, in principle, be sufficient by itself. That would certainly make sense for an RSP that is completely guaranteed to provide the contracted service at all times, since no payment incentives would be required to encourage the RSP to be sufficiently full at all times and should be no more than the expected value of the economic benefits provided by the methodology.

When other components of the potential structure are introduced, this could change the value of the fixed payment. For example, it may need reducing if other payments (such as for availability, as captured by historic state of charge records) are already generous.

For convenience, we sometimes represent this with the mathematical symbol $P^{(all)}$, with the reason behind the 'all' superscript becoming clear below.

4.3.2 Penalties for non-delivery

A penalty for non-delivery would relate to any incidents where the RSP failed to provide the contracted response in the event of a service interruption, which in most instances would be a consequence of having less than the contracted amount of stored energy at the start of the event. As a first iteration, we assume that these penalties are precisely the cost to the DNO of the failure to provide the full service.

In order to ensure the avoidance of any ambiguity in the definition of this proposed payment component, several relevant terms are given a precise definition below, along with mathematical symbols. The terms are:

- t – an index for time. Time is modelled as discrete, i.e., progresses in indexed steps $t = \{1, 2, \ldots\}$. We assume for convenience that time steps are 1 hour in length, although it could be any length.
- E^C – the amount of energy (MWh) that the RSP is contracted to maintain at all times, except in the event of a network disconnection event, when it is expected to meet all demand until it is either empty, or the event is over.
- T – the number of time steps associated with E^C, according to the DNO's analysis. Such analysis will determine that by storing at least as much as E^C at all times, the RSP will be able to fully meet demand for T hours with a very high, pre-defined probability, such as 99%. The duration used in the examples here is four hours.
- $V_t^{(not\ full)}$ – one of a number of related variables capturing a loss of economic value associated with a customer interruption event. We will assume for this analysis that it takes the form of IIS penalties, but the same principles apply for VoLL defined in a broader way. For this particular variable, it is the IIS penalty applied to a disconnection event (at time t) that occurred because the RaaS battery did not have enough energy at the start of the disconnection event to meet the contracted energy provision, which is specified by the DNO to provide T hours of service with a sufficiently high level of certainty. If the RaaS provider delivers exactly as contracted, then $V_t^{(not\ full)}$ will certainly be zero for all t. For a RaaS provider contracted for e.g., 10 MWh, if an interruption lasts for a period of time where the total energy demand is greater than 10 MWh, then $V_t^{(not\ full)} = 0$ for the event, regardless of what happens after the 10 MWh has been supplied. On the other hand, if the RaaS provider only offers 7 MWh, then $V_t^{(not\ full)}$ will be equal to the IIS penalties associated with the missing 3 MWh (only). As with all economic loss variables defined here, the entire cost of the event is attributed to the time t when the interruption event begins.

If we represent the penalties as positive numbers, then non-availability penalties can be viewed as negative payments. If we combine these with the fixed payment, the total payments awarded to the RSP becomes:

$$Total\ Payment = P^{(all)} - \sum_{t=1}^{8760} V_t^{(not\ full)}$$

where 8760 is the number of 1-hour time steps in a year.

One possibility worth considering is limiting the total payment to being ≥ 0, i.e., to stop applying financial penalties to the RSP if there have been so many insufficient responses that the payment has reached zero. If this safeguard is applied, it may be justified to reduce $P^{(all)}$.

4.3.3 Indemnity: analogy with the economics of insurance

It is clear that the DNO wishes the RaaS service to be available (i.e., the RSP always stores sufficient energy) to provide the contracted service at all times. The goal, fundamentally, is to significantly reduce customer interruptions, rather than an economic goal such as stabilising the financial penalties associated with those interruptions. Nonetheless, as the operation of the battery is not under the direct control of the DNO – rather only indirect control via the payment (and penalties) structure, then there is always a chance that the stored energy reserved for RaaS is less than the contracted amount. It is the fact that RSPs would be stacking revenues from other flexibility services that supports the proposal of RaaS as a solution, however this also inevitably opens up the possibility that without sufficient measures being applied, the service may be less than that contracted on some occasions. Implementing an appropriate payment structure can drastically reduce the extent of non-compliance, but measures that would effectively guarantee full compliance may appear unappealing to potential RSPs.

One way to interpret the RaaS arrangement is that the provider essentially agrees to accept the risk of all financial losses associated with faults of a duration of T hours or less. These losses might be penalties levied on the DNO due to IIS incentives, or directly remunerating disutility based on VoLL. Risk here means if the RSP gambles and loses, (i.e., it increases participation in other flexibility markets, or provides multiple services that each require a response infrequently and without much correlation, but one happens to be required immediately after the other) such that there is insufficient capacity to meet contracted RaaS requirements, then the RSP must pay the full penalty. This interpretation allows for some conceptual comparisons to be made with insurance policies, as the RSP now faces possible significant losses even if adopting a relatively risk-averse strategy with regard to such service-stacking conflicts.

On the surface, with this arrangement the DNO might not care about the extent to which the RSP gambles, because any penalties applied are passed directly on to the RSP. However, this is not the case, since there are other indirect and imprecise costs to the DNO associated with relatively frequent interruption events, including their duty of service to customers and reputation with both customers and the regulator. Therefore, the deterrent of financial penalty experienced by the RSP, and its effect on limiting the extent of gambling, is an essential facet of the RaaS solution from the DNO's perspective.

When considering 'risk' in this way, one option is that the DNO should consider accepting back **some** of the financial risk. This may act to make the RaaS proposition more appealing to potential providers, as well as likely reducing any upfront payment to providers.

This acceptance of partial risk by the DNO can therefore be viewed as the DNO acting like an 'insurance provider' and providing some degree of indemnity to the RSP forming the 'insured party'. It could be argued that the more natural position here would be to consider the DNO as the insured party, with the RSP acting as the insurer by accepting the penalty risk in the first place. Nonetheless, it is appropriate for this analysis to take it as given that the risk has already been transferred from the DNO to RSP, and therefore the consideration relates to the idea of a DNO accepting some of the risk back.

In principle the DNO could fully indemnify the RSP, such that the indemnity matches the value of the financial impact, such that in the event of a fault there is no further penalty applied to the RSP for not having the contracted amount of energy, beyond the flat reduction in the fixed penalty. However, this is not advocated for two key reasons: firstly, this passing of risk back and forth seems contradictory, and secondly, it would correspond to a situation known in economics as a 'moral hazard'. That is, a situation whereby the insured party acts in a way that takes on additional risk on the basis that they

are not exposed to the financial implications of that risk - for example, if an individual takes out a phone insurance policy, then there is less incentive for them to take such care of their phone, as in the event of damage at least some of the associated costs will be covered by the insurance provider. In the case of RaaS, the RSP may decide to participate in potentially conflicting flexibility services to a much greater extent, therefore this full indemnity may diminish the incentive for the provider to deliver a good level of service. In cases of moral hazard, insured parties should therefore only be partially indemnified against losses in order to encourage them to maximise their effort to reduce risk and avoid unfavourable events.

It is proposed that the question of exactly how much risk the DNO should be willing to accept back from a RaaS provider, and through exactly what kind of financial agreement, is one that could be informed by the micro-economic theory of insurance. However, the multiple components at play here mean that the application of that theory is far from straightforward, and a full analytical solution is well beyond the scope of this report.

Instead, we propose the following general formulation for consideration, where again simple mathematical notation is used to convey precise meaning:

- $P^{(all)}$ – a fixed payment from the DNO to the RSP, that does not vary at all with the performance of the latter. While such an unresponsive payment might not seem ideal, deductions from this amount can be made for poor performance, so it could (as one possibility) represent the maximum payment made if there is no evidence of non-compliance with maintaining the contracted duration of service at all times.
- $P^{(ins)}$ – the premium paid by the RSP to the DNO as an insurance provider. This is independent of interruption outcomes during a particular year, and the resulting penalties applied to the RSP. It is essentially a penalty applied to the fixed payment, which the RSP would accept on the basis that they are exposed to less risk of incurring costs equivalent to CIs/CMLs or VoLL.
- $P^{(net)}$ – the net fixed annual payment made by the DNO to the RaaS, given by:

$$P^{(net)} = P^{(all)} - P^{(ins)}$$

- $C\left(V_t^{(not\ full)}\right)$ – the indemnity the DNO offers the RaaS provider against losses for which it would otherwise be liable due to storing less energy than E^C in the event of an interruption event starting at time t. The final penalty paid by the RSP due to the events of time t is therefore:

$$C\left(V_t^{(not\ full)}\right) - V_t^{(not\ full)}.$$

  If the RaaS provider has not 'purchased' any indemnity from the DNO then $C\left(V_t^{(not\ full)}\right)$ is always zero. However, if $C\left(V_t^{(not\ full)}\right) = V_t^{(not\ full)}$ for all t and all values of $V_t^{(not\ full)}$, then the RSP has purchased full indemnity with no excess, or in others words has transferred back all of the penalty risk to the DNO. We believe that the best arrangement for both parties would lie somewhere between these bounds.

One further option worthy of consideration is that the indemnity provided by the DNO could be varied dynamically, based on forecasts that use the most recently available information to identify the safest times to 'gamble'. Such gambles would involve informing the RSP that it will be temporarily fully indemnified against penalties and thus free to use battery capacity otherwise reserved for RaaS to participate in other flexibility markets. Effectively, this would equate to a DNO 'standing down' the

RSP for a defined period of time. This additional indemnity should be balanced out through a reduction in other aspects of the RaaS payment structure, so a good estimate of the number of occasions where commercial and engineering judgement mean that this option may be taken, would be essential to ensure the economic efficiency of this concept for both the RSP and DNO. Since such compensatory measures would likely be necessary, there may be cases where this isn't more attractive to the RSP, e.g., if the income from other markets wouldn't be as high as that from RaaS, and/or if they prefer more certainty with regard to operational expectations.

4.3.4 Availability payments

The DNO may opt to add a component to the payment structure that rewards or penalises the RSP based on their availability performance (i.e., the extent to which they retained sufficient energy in the battery to provide the contracted RaaS response) during all time steps of the year. This is in contrast to utilisation payments and penalties that only apply when an interruption event happens to occur. As previously discussed, such a component is only possible if the RSP is able to record the battery's state of charge throughout the year and is also willing to submit this data to the DNO for inspection – as is assumed to be the case in the current research project. For the remainder of this subsection, we assume for convenience that these conditions are true.

Before discussing a number of interesting options for the availability payment, a number of relevant quantities are again formally introduced:

- e_t – the amount of energy that the RSP could provide if a disconnection event were to occur at time t.
- $A(\{e_t\}_t)$ – the total availability payment made to the RSP for storing energy e_t. The payment is, in the most general case, a function of the entire set of e_t values – since, for example, the penalty for being below the contracted level five times might be more than five times greater than the penalty for allowing this once. There are four special cases of this general form that are of particular interest to the current problem; the chosen solution can of course involve any combination of them. The special cases are:

  1. The reward is calculated for each time step individually, as a function of the individual states of charge only. This can be expressed mathematically as:

     $$A(\{e_t\}_t) = \sum_{t=1}^{8760} f_1(e_t),$$

     where $\{e_t\}_t$ means the set of all states of charge (i.e., values of energy available) over the year being evaluated. This is consistent with a single requirement, E^C, that does not vary with time of day, month etc.

  2. The reward is again calculated for each time step individually, independent of the energy held at all other time steps but depends on both the energy value and the time. This time dependency would automatically be the case if the contracted energy requirement varies with time (e.g., time of day and/or month), and written as E_t^C. This arrangement can be expressed mathematically as:

     $$A(\{e_t\}_t) = \sum_{t=1}^{8760} f_2(e_t, t).$$

  3. The reward is again calculated for each time step individually but is dependent on the state of charge for all previous time steps. This can be expressed mathematically as:

$$A(\{e_t\}_t) = \sum_{t=1}^{8760} f_3(e_t, \{e_i\}_{i<t}),$$

where $\{e_i\}_{i<t}$ means the set of all available energy values in the year being evaluated, prior to time t.

One example of this could be that the RSP is given a certain allowance of available energy levels below the contracted value, which may or may not change with time, to varying degrees. For example, the arrangement might tolerate 100 instances (of a possible 8760 per year) where the available energy is up to 5% less than the contracted value, 50 instances where the energy is up to 10% less, and 10 instances where it is up to 20% less. Up to these limits the penalty for unavailability would be quite light but would become much more severe beyond that.

4. The reward is a function of some set of n statisitics extracted from the set of e_t values, expressed mathematically as:

$$A(\{e_t\}_t) = f_4\big(s_1(\{e_t\}_t), \dots, s_n(\{e_t\}_t)\big).$$

For example, the total availability reward could be a function of the mean energy availability only, or possibly of both the mean and 5th percentile, so that $s_1(\{e_t\}_t)$ is the mean availability throughout the year and $s_2(\{e_t\}_t)$ is the 5th percentile of the distribution of available energy values across the year.

If the contracted energy requirement varies with time, it might make more sense to work with normalised shortfalls, i.e.:

$$d_t = max(E_t^C - e_t, 0)/E_t^C,$$

and define the availability payment in terms of these shortfalls as:

$$A'(\{d_t\}_t) = f_4\big(s_1(\{d\}_t), \dots, s_n(\{d_t\}_t)\big).$$

Availability payments could be made dynamic, based on updated estimates of interruption event risk, in an analogous way to the option proposed for indemnity at the end of Section 4.3.3 – indeed this potential 'gambling' could involve either, or both, of indemnified non-availability penalties and availability payments. One further, practical alternative would be for the DNO to offer limited opt-out periods to the RSP and deduct an availability payment based on the number of opt-outs accepted by the RSP, made up for by the lack of potential penalties for non-provision of RaaS during these periods. To make the most of this opportunity, the RSP would require the capability to identify specific points in time during which it would be optimal to utilise the battery capacity otherwise reserved for RaaS to participate in other markets.

A simple option would be for availability payments to be based on pro-rating the value of RaaS evenly throughout the year (e.g., translating the £/year service benefits from Section 3.2 to £/half-hour figures). A further enhancement to this could be to offer differing availability payments dependant on the level of reserved capacity, thereby defining a "menu" of availability payment levels with the amount paid then depending on the state of charge. However, as the value of different levels of reserved capacity to an RSP business case can be evaluated prior to commencing a RaaS contract, this assessment is probably best undertaken as part of the procurement process for RaaS, with the DNO inviting prices for a number of different service levels. Whilst this may not provide a solution which covers the significant majority of fault situations at a given location, it will allow the identification of the most cost-effective solution to still bring benefits to customers.

4.3.5 Utilisation payments

Utilisation payments would make the payment received by an RSP in a given year a function of the value of the actual financial impact avoided through the provision of RaaS. These are essentially rewards paid to the RSP for fulfilling their obligations to supply power when required. This provides them with additional incentives to store sufficient energy at all times and avoid (or limit) the use of the reserved capacity to participate in other, potentially conflicting, flexibility services. Essentially, these are reward 'carrots', complimenting the 'stick' of penalties for insufficient reserved capacity. Since such payments increase the RSP's expected payment, this effect should probably be offset by lowering $P^{(all)}$ and therefore $P^{(net)}$, to maintain an expected annual payment (i.e., probabilistically weighted mean), in line with the value of the RaaS service at the given location (as defined using the methodology presented in Section 3).

A simple mathematical representation of the general form of utilisation payments is presented below:

- $V_t^{(avoided)}$ – another variable related to an economic loss. In this case, it represents the *reduction* in financial impact associated with the level of service provided by a RaaS battery during an event that started at time t. Consider an RSP that is contracted to provide a specific amount of energy, which was calculated by the DNO as sufficient to provide a 4-hour duration of RaaS coverage with 90% certainty, and imagine that the battery's state of charge at the start of a supply interruption event was only 80% of the contracted amount, which turned out to be enough to provide 3 hours of service. Further imagine that the contracted energy level in this case would have supplied demand for 5 hours, and that the event lasted 6 hours. In this case, $V_t^{(avoided)}$ is the economic loss that would have occurred during those first 3 hours if there was no RaaS. The RSP would receive both a positive payment for the 80% of service provided (corresponding to the first three hours) and a penalty for the missing 20% (corresponding to the 4th and 5th hours), with no reward or penalty associated with the 6th hour.
- $V_t^{(long)}$ – an economic loss variable representing the financial impact associated with relatively long interruption events, starting at time t, which only includes the financial impact experienced over timesteps $t' > t + T$. Therefore, if a RaaS service is commissioned to provide sufficient energy to cover a 4-hour RaaS event with 90% certainty, but due to lower demand levels this energy happens to correspond to 5 hours in our current example, then $V_t^{(long)}$ would be the financial impact incurred during the 6th hour. The DNO is fully liable to pay the CI/CML penalties associated with this period in all such scenarios.
- $V_t^{(no\ RaaS)}$ – a hypothetical economic loss variable representing the total loss that would be associated with an interruption event starting at time t, if there were no RaaS service commissioned for the particular network. The purpose of defining $V_t^{(long)}$ and $V_t^{(no\ RaaS)}$ here is that it allows for the following useful equation:

$$V_t^{(no\ RaaS)} = V_t^{(not\ full)} + V_t^{(avoided)} + V_t^{(long)}$$

- $U\left(\left\{V_t^{(avoided)}\right\}_t\right)$ – the element of the payment scheme which rewards the RaaS directly for the reduction it delivered in financial impact during an interruption event that started at time t, where $\left\{V_t^{(avoided)}\right\}_t$ represents the full set of $V_t^{(avoided)}$ values throughout the year.

This aspect of the payment could be set as a constant proportion of $V_t^{(avoided)}$ for simplicity, or an ever-decreasing proportion as the accumulated reward increases, or simply capped. It can, in fact, take any combination of the four basic forms set out in Section 4.3.4 for the availability payment.

One option that seems fair to the DNO, while also being attractive to an RSP – without compromising the motivation to comply with the contracted level of service – is to ensure that the RSP receives at least as much payment as the contribution it makes (compared to $V_t^{(no\ RaaS)}$), without having much influence during a typical year, when this payment floor is not breached (assuming at least reasonable RSP compliance). This could be achieved by giving $U\left(V_t^{(avoided)}\right)$ the form described below:

If the RSP is being paid less than the value it has contributed through avoided penalties, in equation form:

$$\text{If } P^{(net)} + \sum_{t=1}^{8760}\left(C\left(V_t^{(not\ full)}\right) - V_t^{(not\ full)}\right) + A(\{e_t\}_t) < \sum_{t=1}^{8860} V_t^{(avoided)}$$

Then, make up the difference, so that the total payment is equal to the value of avoided penalties:

$$\text{then } U\left(\left\{V_t^{(avoided)}\right\}_t\right) = \sum_{t=1}^{8860}\left(V_t^{(avoided)} + V_t^{(not\ full)} - C\left(V_t^{(not\ full)}\right)\right) - P^{(net)} - A(\{e_t\}_t)$$

else, if the payment *due to other components* is *greater or* equal to the value *contributed, then there is no need for further utilisation-based payment):*

$$\text{else } U\left(\left\{V_t^{(avoided)}\right\}_t\right) = 0.$$

4.4 The payment structure as an economic optimisation

In many ways, it would be ideal to frame the question of the most suitable payment structure as a mathematical optimisation problem (in fact, this is how the topic of payment structures is approached in microeconomic literature). This would fall within the category of stochastic optimisation, since the out-turn of interruption events in a given year, along with the occurrence of competing demand for the RSP's stored energy, are best viewed as random in nature, at least from a modelling perspective. While stochastic optimisation is generally much more challenging than a deterministic equivalent, this approach can be rendered somewhat easier by choosing to optimise the expected value of the reward function. This is the approach that would be adopted for the mathematical problem posed by RaaS.

Although we are considering this topic from the point of view of the DNO, we propose – in line with the academic literature – that the most appropriate goal would be to optimise the RSP's economic utility, subject to constraints that ensure the arrangement would be worthwhile for the DNO. This seems to be consistent with: (i) the fact that DNOs are highly regulated monopolies that cannot access additional income streams ad hoc; and (ii) making the RaaS proposition viable to potential providers in as many locations as possible, and as attractive as possible compared to other flexibility market services.

Although this particular optimisation is a way of simplifying the problem, it may not be sufficient to provide the most attractive solution in practice, since both parties desire at least some measure of stability/ certainty in the payments they make and payments they receive for the service. One way to counter this might be to include a measure of year-on-year variability as a negative term (i.e., disutility) in the function to be optimised. This might require some assumptions of independence to preserve the very desirable linear qualities of the expected value function in a stochastic optimisation. An alternative approach might be to consider how stability (or lack of stability) of payments affects

discount factors and costs of capital within the optimisation, with more stable payment streams likely to lead to reduced costs of capital.

This optimisation problem is clearly challenging, if not impossible, to solve analytically. A significant part of that challenge is in correctly identifying, or at least estimating to an acceptable degree of accuracy, the relationship between different aspects of the payment structure, interruptions and the 'effort' expended by the service provider to limit potential conflicts across the provision of multiple flexibility services. The latter element, which contains behavioural and 'natural' randomness is likely to have a rather complex specification, making the optimisation in turn a very complex task to specify and solve. Further, the space of possible solutions is incredibly vast, yet starting off the search with approximate solutions that are at least reasonably close to the global optimum may be necessary to find that global optimum.

To provide a pragmatic alternative, therefore, for this review we consider some simple potential payment schemes and gain some initial insights about their relative merits in a real-world situation, considering the perspectives of both the DNO and RSP.

4.5 Examples of simplified payment arrangements

In this section, we present some simple and purely illustrative examples of payment schemes, which are special cases of the general structure presented in Section 4.2. We will demonstrate how these schemes are obtained from the general structure and examine their relative merits and shortcomings. To ensure that the examples feel grounded in reality and use real data, the payment schemes are applied to the Kinloch network, which was used to demonstrate of the RaaS valuation methodology in Section 3. Further, each methodology is evaluated against the same simulated set of circumstances, i.e., the same sequence of interruption events and demand patterns.

4.5.1 Fixed payment, full indemnification, no utilisation payments and no availability payments

This is the simplest possible scheme, involving a fixed payment that does not depend in any way on the RSP's performance, nor on the out-turn of supply interruption events. This simplicity would be achieved by fully indemnifying the RSP, so that the unavailability penalty and indemnity payments cancel out to zero, along with setting the utilisation and availability payments to zero. The fixed payment is set to the value of the expected reduction in interruption costs, derived according to the method described in detail in Section 3, which is the most generous offer that the DNO can make with the scheme remaining a cost-effective solution. As previously discussed, this solution would present exactly the sort of moral hazard that a DNO should seek to avoid. Nonetheless it is useful to include this scheme for comparison with more sophisticated schemes.

As with all examples, we consider the case of Kinloch as presented in Section 3.2, and imagine that a RaaS contract commissions sufficient energy to provide a four-hour service, 90% of the time. To elaborate, we assume that a high proportion of the interruption costs (CIs & CMLs) can be prevented with a four-hour RaaS service, and as a result the DNO has calculated the required energy value, or possibly a set of values based on the time of day and/or month, to be available for RaaS on the basis that it would be sufficient to provide 4 hours of service on 90% of all potential event starting times. We assume in our example that the RSP complies (i.e., keeps at least E_t^C of energy free) 90% of the time, and take the rather extreme position that during the 10% of non-compliant hours, there is no energy at all stored in the battery.

Under this simple scheme, the provider receives the fixed payment associated with always storing E_t^C (or simply E^C), derived based on the expected value of this, calculated over many repeated simulations. For Kinloch this is £60,310[32]. They receive this fixed payment in every year. The effective cost to the DNO is then the combination of this fixed payment, and any residual incurred IIS cost. As shown in Table 4-1, in our example scenario for the interruption events that occurred during 5 consecutive years, the average cost to the DNO exceeds the average cost of IIS interruptions of up to four-hours. While this is very attractive to the RSP, it means that the RaaS solution would not be worthwhile for the DNO. While this shortfall between mean 'Total Cost to DNO' and 'Avoided IIS Cost due to RaaS' may partially be due to the small sample size of 5 years (restricted due to the fact that as demand patterns change over time, earlier load profiles may not be as reflective of those seen at present), it also reflects the fact that a fixed payment is purely based on the simulated mean value of RaaS, with no variation to reflect requirements in specific years.

To better understand the table columns and relate them to the variables from section 4.2, note the following relationships:

- The column 'Full IIS Costs' is equal to the sum of $V_t^{(no\ RaaS)}$ values over the year in question, as indicated by the first column.
- The column 'Avoidable IIS Costs with the Contracted Energy' is the reduction in IIS penalties that would be achieved if the RSP was compliant 100% of the time. It is therefore equal to both the sum of $V_t^{(not\ full)}$ values plus the sum of $V_t^{(avoided)}$ over the year in question and the 'Full IIS Costs' for the year minus the sum of $V_t^{(long)}$ values over the year.
- The column 'Actual Avoided IIS Cost' is equal to the sum of $V_t^{(avoided)}$ values achieved by RaaS over the year in question, given the imperfect compliance. Values were calculated as the average over many simulations, with the empty store violations randomly occurring at different times in each simulation.
- The column 'Incurred IIS Cost' is the amount of additional penalties the DNO had to pay, as a result of the RSP's imperfect compliance. It is equal to the sum of $V_t^{(not\ full)}$ values over the year, but again is the mean oven many simulations. However, these values were simply calculated as 'Avoidable IIS Costs with the contracted energy' minus 'Actual Avoided IIS Cost' for each year.
- The column 'Payment to RaaS Provider' is the total payment made to the RSP arising from the payment scheme for that year.
- The column 'Total Cost to DNO' is equal to the 'Incurred IIS Cost' plus the 'Payment to RaaS Provider'. If its mean value is greater than the mean value of the 'Actual Avoided IIS Cost', then the scheme is not a worthwhile proposition for the DNO, for this network (give or take some sampling uncertainty).

[32] Note that, for illustrative purposes, this is an exact match of the average IIS cost associated with the simulated interruptions over the five historic years. In practice, this would only be true in the very long-run. These values were in fact calculated for a fixed duration of service of 4 hours, rather than a fixed energy level, but remain very close to values for the latter case, with a 90% reliability rate of achieving 4 hours.

Table 4-1: Examples for fixed payment with full indemnification

Reporting Year	Full IIS Cost	Avoidable IIS Costs with the Contracted Energy	Actual Avoided IIS Cost	Incurred IIS Cost	Payment to RaaS Provider	Total Cost to DNO
2015	£0	£0	£0	£0	£60,310	£60,310
2016	£53,865	£41,550	£37,395	£4,155	£60,310	£64,465
2017	£65,003	£50,000	£45,000	£5,000	£60,310	£65,310
2018	£33,331	£20,000	£18,000	£2,000	£60,310	£62,310
2019	£240,560	£190,000	£171,000	£19,000	£60,310	£79,310
Mean	£78,552	£60,310	£54,279	£6,031	£60,310	£66,341

4.5.2 No fixed payment, full indemnification, availability payment, no utilisation payment

In this approach, the RSP is offered an availability fee instead of a fixed upfront fee, while still providing fully indemnity against any interruption costs incurred. If the expected value for some hypothetical substation for a service equivalent to a four-hour duration 90% of the time, is £105k, while it is £70k for the similarly nearly reliable two-hour service. Assuming that the availability payment takes the form of a linear sum of individual payments for each hour, these expected rewards translate into availability fees of £6 per half-hour for a (approximately) four-hour state of charge, £4 per half-hour for an approximately minimum two-hour state of charge, and £0 per half-hour for zero available battery capacity. There is clearly an incentive on the provider to aim to have a fuller battery, although if a fault happens to occur during a period where their battery is below its contracted state of charge, then there is no specific penalty.

In Table 4-2 we apply this structure to the same Kinloch example as above, with a difference being that we assume that the full availability payment is made 90% of the time, and for the remaining the time the provider receives a payment of £0. In this simple example, this means that the total payment made is 90% of £60,310, which is £54,279. The total cost to the DNO is this figure of £54,279 plus any IIS cost that is incurred within the year. The average total cost over five years is exactly equal to the average IIS cost for a four-hour approximate minimum duration, which shows that the payment structure is appropriate, although in some years the RaaS provider receives a payment which is much higher than the benefit they provide, and in other years a payment which is much less.

An equivalent alternative to this would be to offer a reduced fixed payment from the outset and give the RSP an allowance of, e.g., 10% of occasions where it does not provide the contracted duration of service, and if there are breaches beyond this level, they might be penalised quite heavily.

Table 4-2: Examples for availability payment with full indemnification

Reporting Year	Full IIS Cost (£)	Avoidable IIS Costs with the Contracted Energy	Actual Avoided IIS Cost	Incurred IIS Cost	Payment to RaaS Provider	Total Cost to DNO
2015	£0	£0	£0	£0	£54,279	£54,279
2016	£53,865	£41,550	£37,395	£4,155	£54,279	£58,434
2017	£65,003	£50,000	£45,000	£5,000	£54,279	£59,279
2018	£33,331	£20,000	£18,000	£2,000	£54,279	£56,279
2019	£240,560	£190,000	£171,000	£19,000	£54,279	£73,279
Mean	£78,552	£60,310	£54,279	£6,031	£54,279	£60,310

4.5.3 Fixed payment, no indemnification, no availability payment, no utilisation payment

Another simple option would be to include a fixed payment based on the expected value of the contracted (e.g., 4-hour) service, as described above, but also to provide no indemnity to providers in the event that the service does not meet requirements when a disconnection is experienced. In this case, the RSP would pay the full IIS penalty (or VoLL cost) of any interruptions that occur.

Again, we apply this structure to the Kinloch example with the results shown in Table 4-3. In this case, the incurred IIS cost for the DNO is deducted from the fixed payment to the RSP as a penalty for non-delivery. Again, the total cost to the DNO matches the maximum possible IIS reduction, and the average payment to the provider is the same as in the previous case, matching the actual avoided IIS cost. The main difference is the significant year-on-year variation in the total payment received by the RSP: in the final year, this is only around 2/3 of the “headline” fixed payment.

Table 4-3: Examples for fixed payment with no indemnification

Reporting Year	Full IIS Cost (£)	Avoidable IIS Costs with the Contracted Energy	Actual Avoided IIS Cost	Incurred IIS Cost	Payment to RaaS Provider	Total cost to DNO
2015	£0	£0	£0	£0	£60,310	£60,310
2016	£53,865	£41,550	£37,395	£4,155	£56,155	£60,310
2017	£65,003	£50,000	£45,000	£5,000	£55,310	£60,310
2018	£33,331	£20,000	£18,000	£2,000	£58,310	£60,310
2019	£240,560	£190,000	£171,000	£19,000	£41,310	£60,310
Mean	£78,552	£60,310	£54,279	£6,031	£54,279	£60,310

4.5.4 Reduced fixed payment, partial indemnification, no availability fee, no utilisation fee

An alternative approach, and one which would reduce this year-on-year variation, would be to reduce the fixed payment somewhat but compensate for this by providing a partial indemnification in the form of a reduced penalty.

Returning to the Kinloch assessment, the fixed payment offered in this example is 95% of the expected reduction in IIS costs due to the full service, which for Kinloch would be £57,294.50. When interruptions occur due to the battery having less than E_t^C MWh available, the assumption applied in this example is that half of the associated IIS costs are paid by the DNO, and the other half are passed through as a penalty to the RSP. As shown in Table 4-4, the average cost over the five years is the same, but there is much less variation between years in the payments made to RaaS providers, which would obviously be more appealing.

An alternative way to achieve this would be to split the expected cost between a fixed payment, and an availability payment (e.g., pay half of the expected value up front as a fixed cost, and then convert the rest into a half-hourly availability payment). Other, more complex arrangements involving utilisation payments as well could also be included but are not included here for the purposes of brevity and clarity. There is certainty considerable scope here to explore a much wider selection of potential structures and options and parameter values, potentially through the use of an interactive tool, with visualisations included.

Table 4-4: Examples for reduced fixed payment with partial indemnification

Reporting Year	Full IIS Cost (£)	Avoidable IIS Costs with the Contracted Energy	Actual Avoided IIS Cost	Incurred IIS Cost	Payment to RaaS Provider	Total cost to DNO
2015	£0	£0	£0	£0	£57,295	£57,295
2016	£53,865	£41,550	£37,395	£4,155	£55,217	£59,372
2017	£65,003	£50,000	£45,000	£5,000	£54,795	£59,795
2018	£33,331	£20,000	£18,000	£2,000	£56,295	£58,295
2019	£240,560	£190,000	£171,000	£19,000	£47,795	£66,795
Mean	£78,552	£60,310	£54,279	£6,031	£54,279	£60,310

4.5.5 Observations on worked examples

Within these worked examples, we were able to achieve several different payment structures which result in the same payment to providers (when averaged over the 5 years in the example) and the same total cost for DNOs, which is linked back to the valuation derived from the probability-based simulation methodology described in Section 3.1. It is very important to stress that such neat examples were only possible due to the number and duration of the interruptions, and therefore the associated value of the RaaS service, etc. being known to the authors – due to being based on historic data. Achieving such perfectly balanced results for a small sample of years – when the payment levels have been set ex-ante, based on results drawn from many 1000s of simulated sample years – would be very difficult if not impossible in real life, where interruptions are not known in advance. These examples have also not required any knowledge about how penalties and payments may affect provider participation in other flexibility markets for revenue stacking. This information would support the development of optimal payment schedules, if that were attempted. It is recognised that this

understanding will build considerably with the future roll out of RaaS and information acquired through tender processes.

The main difference in these examples is the amount of year-on-year variation in the payments made to providers, which is highest if providers are exposed to penalties. This variation can be reduced by reducing or removing the penalties then offsetting that by reducing the fixed or availability payments.

It is difficult to say with any certainty which of these example solutions is the best, from either the DNO or the RaaS Service Provider's perspective, without being able to formally solve the mathematical formulation of the problem as an optimisation problem, which may be impossible. We also repeat that these are not presented as candidates for the optimal solution and represent a very small fraction of the range of possible solutions. However, one likely outcome is that providers will prefer payment structures that are less volatile and give them more certainty of their revenue streams. This is likely to favour either availability payments and reduced penalties, or a cap on penalties applied for a given year through utilisation payments. It is noted that the RaaS project has the option to explore the attractiveness of these potential payment structure through their planned stakeholder and supply chain engagement activities over the course of the operational trial period.

5 The role of forecasts

The potential role of forecasting within the operation of RaaS, including payment schemes, has been discussed in previous sections of this report, in particular in Section 4. This section examines this role in significantly more detail, as well as considering exactly what should be forecast and what type of forecasts might be most appropriate.

5.1 Overview of forecasting state of charge requirements

The RaaS concept is centred on the idea of a consistently available service that would prevent customer disconnection in the event of disconnection from the grid for a defined number of hours. This duration of service then has implications for the useable energy capacity (MWh) that needs to be available from the battery to provide the RaaS service. Similarly, the forecasted demand pattern has implications for the required power export (MW) capability. Each of these requirements will change throughout the year, the week and the time of day. Forecasting is clearly necessary, and indeed of central importance when anticipating power and energy requirements for a proposed RaaS scheme. Since those forecasts can never be perfect, even when produced only a few hours ahead, the required MW and MWh values cannot be known with certainty. This is true for predictions for a specific hourly or half-hourly interval in the future, and also when forecasting the 90th percentile of demands over a specific segment of hours, such as the winter evening peak period. There is a need for forecasting on multiple time scales:

1. Planning timescales – so that the optimal MW and MWh capacity of the battery can be calculated. The DNO does not know for sure what the peak demands will be over the duration of the proposed contracts, which presumably will cover a period of multiple years. However, data is available to make such predictions, including LTDS [33] information and DFES [34] projections, with further tools being developed through other innovation activities (such as the forecasting tool created by the consultancy SIA Partners for the LEO[35] and TRANSITION[36] projects);
2. Operational timescales – to calculate how full the battery must be to deliver a fixed duration at a specific point in time, and with a fixed level of confidence (such as 90%). If the forecast is to indicate the requirement for time t, and the required duration is four hours, then a forecast for hourly averaged demands for times t to $t + 4$ is required (since the fault may occur at the very end of hour t).

Therefore, there is clearly a strong need for demand forecasting on both timescales.

Short term demand and embedded generation forecasting for operational purposes, particularly at such fine spatial granularity, is still relatively nascent for both DNOs and the providers of emerging flexibility services. However, good quality forecasts are still likely to be possible, but challenging, and further innovation work may be necessary. The interesting questions of exactly what type of demand forecasts should be produced, and who might be best placed to produce them are discussed in the following two subsections.

[33] DNO Long Term Development Statements - e.g., www.ssen.co.uk/ltds
[34] Distribution Future Electricity Scenarios, SSEN, 2020 - www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=20283
[35] https://project-leo.co.uk
[36] https://ssen-transition.com

In addition to forecasts of demand over different timeframes, the RaaS concept has scope to include forecasts of potential risk of interruptions, and/or forecasts of income available to the RSP from other flexibility services markets at different points in time. This section is primarily focused on demand forecasting, but consideration is also given to these other elements of forecasting.

5.2 Comparison and implications of demand forecasting options

This section will consider the suitability of various options for the type of operational forecasts used to ensure that a sufficient supply of energy is held in the RSP's battery storage plant in order to provide the RaaS service sought by the DNO. The suitability of the forecast type for use both ex-ante (defining) and ex-post (evaluating) a scheme is considered. It is vital to note that the quantity being forecasted here is not just the demand during one time step (i.e., hourly average demand converted from MW to MWh), but rather the total energy demand over four hours (i.e., the sum of four hourly-average demand values, converted from MW to MWh).

For convenience, we assume that the relationship between the energy stored, and energy delivered is linear, unchanging in time and given by the battery scheme's export efficiency. We also assume that energy leakage can be ignored. This means that we can forecast the energy delivery requirements and can convert these to energy storage requirements in a simple way.

There are three fundamental options for the type of demand forecast that could be used to forecast the stored energy requirement:

1. Forecasts derived as a percentile from a historical record of demand;
2. Probabilistic forecasts that are issued close to real time, making use of the most recent relevant observations; and
3. Point forecasts (i.e., single values) that are also issued close to real time and use recent observations, but which provide a central estimate of what might happen, taken as a best guess of what will happen.

5.2.1 Percentiles of historical demand

Such forecasts would be produced by obtaining historical records of demand for the primary substation being considered, then partitioning the data according to an agreed number of service windows. Examples of such windows proposed by E.ON[37] are: (i) An initial split into four seasons together with a distinction between working and non-working days, (ii) as per the previous example, however with a further division into six four-hour blocks per day.

This may not be a particularly efficient option, economically, since the battery is always kept full enough, within each service window, to meet demand during the most heavily loaded four hours, (e.g., the 90th percentile of demand as recommended elsewhere in the project), despite the requirement being lower most of the time. This is particularly notable if there are not multiple service windows for different times of day. In principle, the efficient choice of percentile will depend on the balance between the expected avoided cost of interruptions versus the opportunity cost of reserving stored energy for RaaS.

Further, the peak demand levels for each service window are not necessarily at the same time each year, so a sample of historical demands covering e.g., one year, is not necessarily a completely accurate predictor of the 90th percentile for near-future years, even if the underlying processes driving

[37] RaaS 'Flexibility Scenarios' report (E4.1), E.ON, November 2020, https://project-raas.co.uk

demand have changed very little. However, the annual variability in 90th percentiles may be less significant than variability in the mean and may indeed be one of the most stable statistical metrics of the demand series. As a side note, it may be tempting to talk about the demand in terms of load curves, but that is not appropriate in the present context, since load curves are inherently about mean values, while the percentile approach must work with raw data rather than mean values to reflect demand patterns.

By choosing the 90th percentile, and assuming that the probability of a fault is uniform throughout each service window, then there is already a 10% chance that the amount of stored energy would be insufficient to provide a 4-hour service. Therefore, the service would only be 90% sufficient even without any "gambling" from the RSP with regard to the provision of other stacked flexibility services. However, this does not mean that the benefit offered by the RSP would be 10% lower than an RSP with perfect foresight of demand – the number of occasions where the RSP could completely cover the required period would be 10% less, in the long run, but the MWh saved would be higher than 90%.

However, it may be the case that the probability of an interruption event is positively correlated with demand (e.g., both caused by wintry weather) in which case the probability of insufficient stores of energy during an interruption would be higher than 10%, potentially considerably higher if the correlation is strong.

One advantage of this 'percentiles of historic demand' approach is that it would avoid the financial and human resource cost of developing forecasting methodologies that are specific to each primary substation with RaaS in place, and taking into account detailed information on different custom types, etc. It would also make verification of whether the RSP acted in good faith to reserve sufficient energy to provide a RaaS service more straightforward than the other options, even where the RSP were to use its own forecasting system, separate from any DNO forecasting.

It is worth noting that if the service windows are defined by time of day, the stored energy requirements for one window do not entirely reflect the demand levels within that window. For example, if one service window covers the evening peak level of 5:00 – 9:00pm, then the highest energy requirement might be at outside of that window at 4:00pm, to cover 5:00 – 8:00pm, as well as 4:00 – 5:00pm.

5.2.2 Probabilistic dynamic forecasts

Such forecasts are referred to as dynamic, since they use newly available information such as recent demand observations and weather forecasts as inputs into an algorithm that produces up-to-date forecasts of demand, on a scale of up to a week ahead of real time. Using such forecasts is essentially equivalent to dividing the year up into 8760 service windows and using knowledge of recent events to make the forecasts as accurate as possible.

The word probabilistic here refers to the fact that such forecasts are concerned with describing 'what could happen' rather than simply predicting 'what will happen'. More specifically, for a continuous valued quantity such as energy, a probabilistic forecast allows calculation of the probability that the outcome will be within a certain range of values. This means that an explicitly risk-based approach can be adopted.

Just as a specific percentile was chosen for the approach based on a historical data sample, it will also be appropriate to do so when using probabilistic dynamic forecasts, in order to ensure that the risk of the stored energy being insufficient is kept acceptably low. As with forecasts from historical data, choosing the 90th percentile here means that on average the stored energy will be insufficient to

supply all demand for a full four hours across 10% of time steps – although the shortfall may mean that the duration of service is only a few seconds short of 4 hours, and indeed it is likely that most shortfalls will be fairly minor. Indeed, the partial nature of the forecast error means that the total benefit delivered will be much higher than 90% of that delivered by a completely certain forecast created with perfect foresight.

One point of difference with the historical data approach is that the risk of not fulfilling the intended service duration is constant – across the time of day, day of the week and across the year. This naturally means that the risk of failure to meet the planned duration is not affected by any relationship that might exist between demand and the risk of an interruption event. The price of this constant risk level is that the capacity requirement for the battery would be higher: the 90th percentile of possible values during peak demand times is higher than the 90th percentile of the distribution over all times.

Probabilistically forecasting the aggregated energy demand over four hours will require a bespoke forecasting tool that has captured the complex statistical relationships that govern how uncertainties persist or cancel out over time. It must be noted that the 90th percentile of the energy demand aggregated over for hours is not the same as the sum of the 90th percentile values for the individual hourly time-steps.

5.2.3 Dynamic point forecasts

Dynamic point forecasts also involve the use of recent observations to make the most accurate predictions possible. However, the main difference is that these forecasts aim to make the 'best guess', or more formally a central estimate of what is going to happen, as opposed to assigning probabilities to various intervals. Typically, the central estimates will be expected values (essentially the mean) for the energy demands, or alternatively the median values. It could be argued that if a constant percentile is always taken from probabilistic forecasts, then these are also essentially single values 'point' forecasts. However, if a forecasting tool is designed to produce single values, it is quite fair to assume those values will be central estimates.

If the errors of a forecasting tool have a mean value of zero, as should be the case, and their distribution is nearly symmetric, then the probability of the energy stored being enough to provide the service for the intended duration will only be about 50%. This initially seems unacceptable, although it might be mitigated by adding a certain buffer level to the dynamic requirements. This would mean the value is initially calculated analytically, but with possible replacement by a rule of thumb acquired through experience. It may also depend on the spread of the errors of the forecasting tool, i.e., errors with a mean that is not quite zero, but a very narrow spread could be more acceptable than a mean of zero with a very widespread.

This system would not be as appropriate as the use of probabilistic forecasts but would probably be cheaper to develop and apply.

5.3 Options for the party responsible for generating the forecasts

One of the most interesting questions in relation to forecasting is: who should have the responsibility of producing them? For example, should SSEN go out to market and say: "we need a 4-hour RaaS service for substation X, which has a peak demand of 1.5MW". Or should they say: "we need an energy requirement of 4MWh/1.5MW for substation X, which we expect will provide a 4-hour RaaS service". Following this, if peak demand turns out to be higher than 1.5MW, and/or the energy required was greater than 4MWh, resulting in a financial impact of interruptions not accommodated by the scheme due to that under-estimate, should the resulting penalties be borne by the DNO or the RSP? Similarly,

on the operational timescale, would the DNO provide a real-time feed of the forecasted state of charge requirement to the RaaS provider? For example, "in 4-hours' time, your battery needs to be charged to 10MWh because we anticipate 2.5MW average demand for four hours." Or would it be up to the provider to forecast the demand and maintain the correct state of charge?

If the DNO undertakes the forecasts then it may give providers more certainty as to what is required and reduce risk, which could make it a more attractive service market. It is also likely that only the DNO has data available to produce robust forecasts of required service levels for each service window, in both the operational and planning timescale. On the other hand, if the DNO passes the forecasting responsibility to its providers there is then potentially an opportunity for further innovation: e.g., a provider might be able to provide a very good value service based on very accurate and reliable forecasting.

The potential (non-exhaustive) uses of the DNO's own forecasting tool(s) in relation to RaaS are:

- Sharing the forecasts ex-ante with RSPs as guidance. Providing such tools might make the prospect of providing RaaS more attractive to potential providers and could help the DNO reduce risks.
- Using them ex-post to translate MWh of available stored energy to durations of service for every hour of the year, if availability payments are to be applied. Where a RaaS service is contracted for duration, rather than specified energy requirements, this would probably a fairer measure than considering the outcome demand levels, since it is not necessarily the RSPs' fault if demand turns out to be significantly higher than forecasted. If historic data percentiles are used, rather than dynamic forecasts, then arguably it is fairer to use out-turn demand values instead.
- Using them ex-post again to translate MWh of available stored energy into durations of service, but only for hours when a disconnection event occurred, and so the available capacity had an impact on the RaaS response.

Considering the RSP's perspective, the options regarding the use of forecasts are:

1. The DNO generates forecasts either with their own tool or by taking a percentile from data they hold, which it shares with the RSPs, possibly as part of the procurement process or possibly for a fee (where some RSPs may have their own forecasting tools). It may however be the case that DNO generated forecasts will only provide point forecasts, in which case where an RSP is contracted to provide a fixed duration of service (as distinct from being contracted to provide a specified energy requirement), the RSP may need to consider the development of a rule of thumb buffer (or a more comprehensive technical analysis) to address potential uncertainties. The accuracy of the forecasts as well as the buffer specifically for primary substations serving remote communities would also need to be verified.
2. The RSP generates its own dynamic forecasts and (i) shares them with the DNO; or (ii) does not share them. This could allow for the prospect of intellectual property by the RSP to add further value to their offer, e.g., if their forecasts perform better than any available to the DNO. However, exactly which measure determines which one is superior may not be a straightforward matter and would relate to a number of subtle questions around what level of quality the DNO should expect/tolerate from the RSP's forecasts, particularly if using this as a basis for calculating payments. Further, agreeing to allow the RSP to use its own forecast may be perceived as an additional risk by a DNO.

3. The RSP does not use dynamic forecasts, rather only using percentiles of historic data. This has several advantages due to its simple and unambiguous nature, as discussed above, but its suitability is dependent on the possible relationship between demand and interruption risk.

Considering forecasts of the risk of interruptions, if it becomes possible to provide operational time-scale forecasts of the relative risk of an interruption event at a given point in time, then clearly the DNO would be best placed to do this. Similarly, the RSPs may be keen to produce forecasts of flexibility market prices in order to decide upon the best times to 'gamble' or 'opt-out' of providing the full RaaS service (as discussed in Section 4.3.4). It may be advantageous for the DNO to also produce such forecasts to be reviewed (perhaps automatically) alongside the interruption event risk, to perhaps trigger a warning when a combination of high interruption risk and high risk of non-delivery coincide – and perhaps counter this risk by offering special 'emergency' rates. On the other hand, as the provision of cost-effective flexibility services is in the best interest of both customers and network operators, it may be that in future all services and potential risks are considered alongside each other in real-time to provide an integrated signal to service providers.

5.4 Forecasting to target RaaS service activation

The benefit, and cost effectiveness, of RaaS could increase significantly if it is possible to 'target' the times at which the service is activated to the times where the risk of interruptions is highest. For example, it could be possible to identify an "80/20" rule, where having the service available with full reliability for a carefully selected 20% of all hours could in fact deliver 80% of the benefits of full reliability for every hour of the year, even if there is no availability during the remaining 80% of hours. If such important subsets of time-steps could be identified, this could significantly help with making RaaS attractive in a competitive environment for providers, whilst still providing significant benefits to DNO customers.

If any times of relatively high and low risk can indeed be identified, then this information could be used to influence RSP behaviour through the payment scheme. Such signals could take the form of availability payments that vary with time of day and time of year or reducing unavailability penalty indemnity during the riskiest times. When signals indicate that the risks are low, this may be interpreted as a voluntary opt-out opportunity being offered to the RSP for those times, with very little financial penalty, or potentially none.

The identification (and subsequent signalling) of the riskiest times can either be done on a planning or operational time scale. On a planning time scale this would involve analysing historical data sets to identify particularly high and low risk combinations of times of day and seasons. For an operational approach, it would also be necessary to consider those regular cyclical factors, but also weather factors. With weather included, models can be developed that can issue dynamic forecasts of the risk level, and it is likely this would take the form of logistic multiple regression models.

TNEI has conducted some exploratory analysis of the historic fault data provided by SSEN, which has enabled some tentative conclusions to be drawn about the prospects of such static and dynamic interruption risk forecasts. The results and tentative conclusions may be summarised as:

- There are, unfortunately, no particularly strong seasonal or time-of-day patterns within the historic fault data available for analysis. There is, in fact, an interesting spike in the number of historic faults that occurred between 09:00 and 10:00 am, and a somewhat lower tendency for faults to occur overnight, but these are likely to reflect night-time faults being discovered and/or logged as the workday begins. There seems to be a higher risk in winter, and possibly July, but the difference is not particularly pronounced.

- However, there are a significant proportion of faults where the cause is recorded as either wind or lightning. Indeed, this accounts for 1/3 of the historic IIS cost between 2015 and 2019, aggregated across the sites for which data was available.
- These causal attributions must be treated cautiously as they may be self-fulfilling to an extent: e.g., if a fault occurred when it was windy, it may be marked as caused by wind if it is not clear that there is any other cause.
- It may still be possible to get some understanding of periods of elevated risk. For example, if lighting risk is higher, or if wind speeds are above a certain threshold, then activating RaaS at these periods might catch, for example, 1/5 of interruptions and may only be required for a much shorter period of the year.

To present the results in greater detail, the number of historic faults by hour of the day, and by month, are shown in Figure 5.1 & Figure 5.2 below.

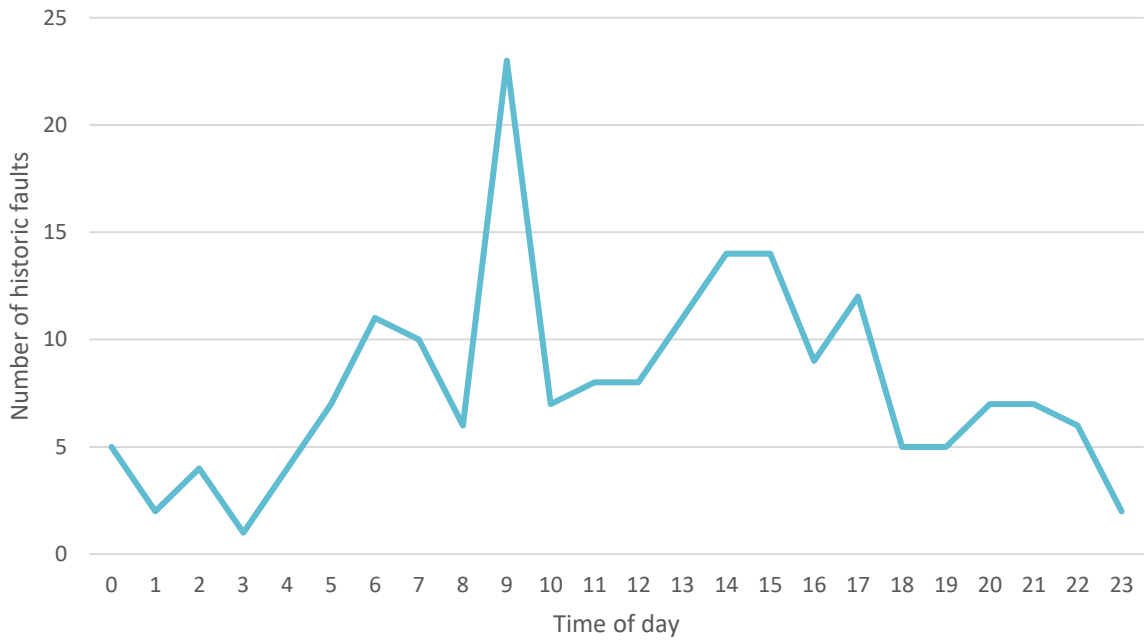


Figure 5.1: variations in the number of faults recorded by time of day, aggregated over all available fault data.

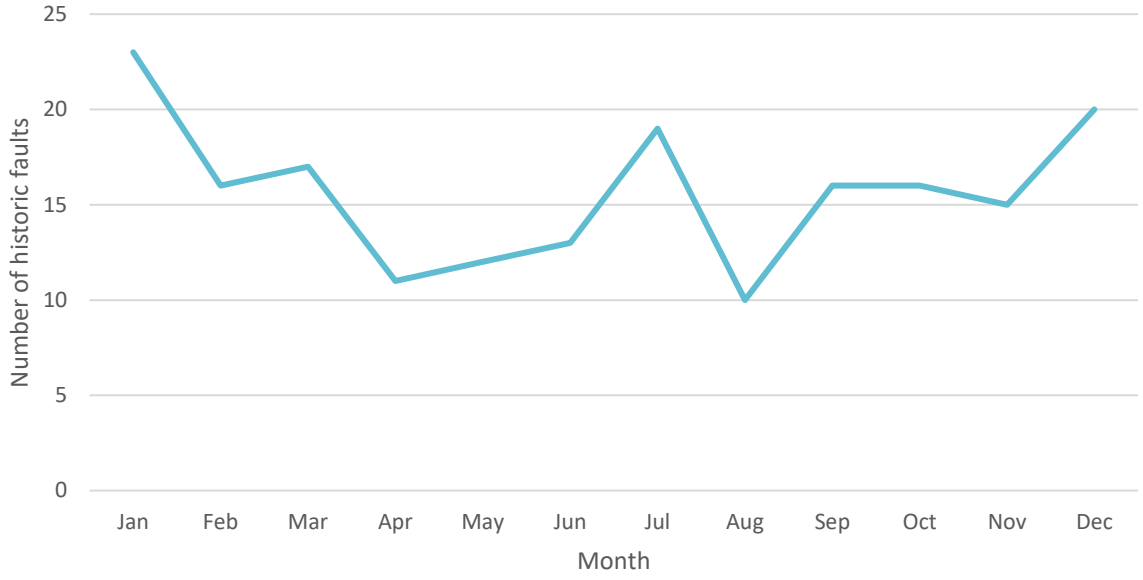


Figure 5.2: variations in the number of faults recorded by month of the year, aggregated over all available fault data.

Another additional option may be to use the RaaS service during periods of scheduled maintenance for networks that otherwise do have redundancy - e.g., during the summer when a network is operating in an N-1 configuration due to maintenance works on one EHV circuit. The risk of interruptions and therefore benefits may well be much lower at such sites. However, the service requirements will be much less onerous, and the volume of applicable sites will be much higher. This might enable greater economies of scale (e.g., 10,000 or 100,000s of sites with £100s of benefit per year), so adding this very targeted RaaS use case to a number of other stacked services for third party owned batteries at such sites may well make economic sense.

6 Conclusions

This section provides some conclusions about TNEI's review of the RaaS business case from the DNO perspective, including:

- Comments on the approach taken to valuing the service.
- Observations on payment mechanisms and structures.
- The role of forecasts.
- Views on the benefit of the RaaS concept, and
- Options for further work and analysis.

Each of these aspects are discussed in the following subsections. However, it is also worth noting the extent to which all of these considerations interact with each other and the dynamics of wider flexibility markets. There is clear benefit to be realised for customers by reducing interruptions, but the extent of the net benefit is heavily dependent on the cost of providing the service, and the opportunity cost[38] of not being able to provide other services. A well designed RaaS service can play some part in reducing these costs and opportunity costs, mainly by using skilful forecasts and a payment structure that encourages participation. However, the designs of the other service markets in which the RSP will be participating could be just as important, and a silo mentality when designing and operating those markets is likely to have a significant detrimental impact on the economic viability of RaaS, or indeed other flexibility services use cases.

Another common theme to many aspects of this review is the nature of the marginal benefit of increases in the required service level. For example, for many demonstration sites it has been shown that the marginal benefit of increasing the service duration decreases. In contrast the marginal benefit of increasing the reliability of the service is expected to be constant (in expected value terms). This is important as the marginal cost and/or opportunity cost of providing the service could easily be increasing, and possibly non-linear. This could mean that the optimal level of RaaS for many locations is far below the year-round six-hour capability that was envisaged at the start of the project. Essentially, in the absence of a cost-effective network reinforcement option, even small improvements in resilience could be beneficial.

In general, it is important to bear in mind that the maximum net financial benefit from RaaS will be created by contractual arrangements which maximise the difference between the benefit created by the service, and the cost of providing the service. Our valuation suggests that increased levels of service may be associated with diminishing marginal benefit. Alongside this, it is possible to imagine that these might be associated with higher marginal costs. In this case, the financially optimum level of service may be quite modest.

[38] It should be noted that by discussing the fundamental economic concept of opportunity cost here, we are not suggesting that the presence of RaaS among a suite of flexibility services primarily represents lost opportunity for a battery owner/ operator. Rather, the addition of RaaS would almost certainly bring a net benefit to them – the economic analysis simply claims that the battery operator would balance these services to obtain maximum benefit.

6.1 Valuing the RaaS service

Section 3 of this report described and demonstrated a methodology for determining the value of RaaS, based on expected reductions in the financial impact of interruptions. This method is based on a statistical simulation of interruptions and relies on data about historic interruptions and substation demands, and assumptions about how interruptions drive costs.

While the method appears to work well, enhancement of inputs, wider scrutiny of assumptions, and further development of the associated process should be considered, if possible, before formally adopting this approach as part of a formal valuation for RaaS services. In particular, the mathematical representation of the duration and frequency of interruptions could be refined further, potentially to incorporate more data, subject matter expertise, and information about different types of interruption experienced, including transmission outages[39]. When looking at the value of the service in the long run, it might also be necessary to account for factors like increasing frequency and severity of extreme weather events associated with climate change or degradation of network infrastructure, both of which might lead to greater numbers of and/or durations of interruption.

The demonstration of the proposed method also suggests that quite different service values could be justified if valued using IIS incentives costs compared to underlying estimates of VoLL. It is likely that IIS costs underestimate the true VoLL, particularly for interruptions that are unusually frequent or last for a long time. However, the benefit of using IIS costs is that it is clearly justified under the existing DNO regulatory mechanisms, whereas VoLL estimates are somewhat more subjective (even with the recent research projects from ENWL). However, it is worth noting that there is support within P2/7 and EREP130 for DNOs to value services using other estimates of VoLL.

It is important to bear in mind that even a measure like VoLL may not capture all of costs or benefits associated with interruptions. For example, there may be a reputational cost associated with high levels of interruption and reducing this would provide benefit. Assigning an economic value to such benefits would likely prove to be very difficult.

One other observation about the demonstration of the methodology is that, in many cases, the marginal benefit of increasing the service duration beyond an hour or two is not very high, particularly when valuing based on IIS. DNOs should therefore consider retaining some flexibility when tendering for RaaS, perhaps inviting bids for a range of different service durations and then evaluating the costs of each service against the benefit in order to determine the best course of action (i.e., most cost-effective scheme for a given site).

6.2 Payment for RaaS

Section 4 provides a set of versatile building blocks for designing an optimal (or near optimal) payment structure for RaaS. This includes a set of principles which should guide the design of a payment structure, as well as a wide range of components that could be used within that structure, including fixed payments, availability payments based on state of charge, and utilisation payments & penalties that depend on actual interruption costs.

These building blocks are very flexible and may even allow a wider set of possible contractual arrangements than SSEN and the RaaS project team are currently considering. For example, these payments structures could work for both contractual arrangements that (i) mandate certain levels of service from an RSP that must be fulfilled, or (ii) incentivise a high quality of service while still leaving

[39] Faults occurring on the transmission network would be addressed by the TO, however a RaaS service would still benefit customers within the RaaS area of the distribution network.

this up to the discretion of the RSP. The rationale of the latter approach is the same as the rationale which might favour lower duration services: if the marginal benefit of a highly reliable service is less than the marginal cost of an RSP providing that level of reliability (compared to being slightly less reliable), then a DNO may be better placed accepting the lower level of reliability. This could particularly be the case if an RSP wants to provide other services that need to be available very frequently, but which are dispatched very rarely, in which case battery capacity may be offered on standby to provide a number of services at the same time, and only be unavailable for RaaS on the rare occasions that another service has required the battery to discharge.

In principle, there are many different payment structures that could satisfy the guiding principles set out in this Section. We believe that one sensible and theoretically justified approach would be to seek an optimal structure, defined as the one which maximises the expected reward for the RSP – possibly with an additional penalty function to reflect the stability of payments, conditional on the DNO not expecting to be at an overall loss. The rationale here is that the solution that maximises RSP reward is also likely to maximise the interest from flexibility market participants to also offer (the competing service of) RaaS. However, mathematically determining which structure is optimal has not been possible within the scope of this report. This is largely due to the difficulty in defining some of the important probabilistic relationships that would be important for such a mathematical solution, such as the effect that payment levels may have on the behaviour of the RSP and its battery's state of charge.

Nevertheless, the report describes some examples of how these building blocks could be combined and provides some commentary on their suitability. In general, it is anticipated that RSPs will prefer structures which lead to more stable revenue streams, which may reduce service costs by reducing financing costs due to higher certainty of revenue streams. SSEN and the RaaS project team are encouraged to explore these building blocks further to find a structure that feels appropriate, including through the planned stakeholder and supply chain engagement activities over the course of the operational trial period. Over time, further analysis and experience from the procurement and implementation of RaaS will also provide more certainty on how different payment mechanisms work in practice.

6.3 The role of forecasts

Section 5 provides a short discussion of the role of forecasts within RaaS. Forecasts are crucial for the effective operation of RaaS, particularly for determining the necessary state of charge of a battery ahead of time.

There are several viable options for (i) the type of demand forecast to be produced, (ii) who is responsible for producing them, (iii) how these forecasts are used. Each of these options has its own strengths and weaknesses, and there are trade-offs to be considered such as the appropriateness of the forecast vs the cost and effort of producing it. The ultimate choice of forecasting approach is likely to depend on the requirements and capabilities of potential RSPs as well as DNOs.

Another possible role for forecasting would be the prediction of periods where there is a heightened risk of interruptions. There is some reason to think this might be possible, with extreme weather (such as lightning and high windspeeds) being a relatively common cause of interruptions. However, there are still many types of interruption which would be very difficult to predict dynamically. This may be another example where the marginal benefit of protecting against all interruptions is difficult to justify when considering the marginal cost of the service, and it is worthwhile (both for customers and DNOs overall) to use RaaS to prevent a comparatively small proportion of interruptions – say 20% to 50% –

on the basis that this leads to a much more significant reduction in the RSP's opportunity costs, requiring a much lower proportion of income from RaaS.

6.4 The benefit of RaaS

Section 3.4 considered the implications of the proposed valuation methodology on the GB-level business case for the RaaS project, considering sensitivities with different service durations, and different levels of replicability across the country.

One observation on the valuation methodology is that, if using IIS as the basis of valuing the service, then it is possible that a year-round RaaS service may be cost-effective on a smaller number of sites than initially considered within the NIC CBA submission to Ofgem. However, even if RaaS only proved to be viable on the ten sites which, using the assessment methodology applied for the NIC submission[40], have the highest overall level of benefit, this would still result in an overall GB level net benefit of £26m. This is less than the figure included in the submission to Ofgem, but even in this very pessimistic case, the benefit is still greater than the total funding required for the project. Further, the number of opportunities may increase as costs of battery storage decrease, or as additional applications for RaaS emerge, such as those presented in the RaaS 'Investigation into the Wider Potential of RaaS' report[41], resulting in economies of scale across the supply chain.

However, it is also important to note that the assessment of the GB-level business case would also require an update to the assumptions regarding the fee for a RaaS service. At the time of writing this report, this is still being assessed through work undertaken for project partner E.ON, and it is understood that the DNO business case and RaaS Service Provider business case will be drawn together by the project team following completion of this report. In addition, another key input to the GB-level business case is an estimate of the suitability of this concept for sites across the country. This was estimated within the submission to Ofgem, but a more detailed assessment of the number of possible RaaS sites across other DNO licence area would also add insight here.

This additional information could be assessed together with the valuation methodology described in this report to provide a further refined view of the potential GB-level benefits. To this end, it can be noted that whether RaaS is viable for a location depends on (i) the benefit that the service creates by reducing interruptions, (ii) the cost and opportunity cost of a battery providing that service, and (iii) at what level of service duration and/or reliability does the benefit outweigh the cost, noting that both costs and benefits will change with the definition of the service. Whilst it may be outside the current scope of the RaaS project, this assessment could be undertaken where:

- Historic data on both interruption frequency and duration, as well as historic demands, could be sourced for a much wider group of substations, including those outside of SSEN's networks.
- Service costs could be determined for each of these substations, based on the analysis completed by the RaaS project team.

[40] The NIC submission methodology evaluated benefits based on a comparison against conventional reinforcement, and against the use of DNO owned energy resources that are only used for resilience (with no revenue stacking capability - the CBA did not incorporate assessment of the financial value of interruptions (i.e., CIs/CMLs, or VoLL).
[41] RaaS 'Investigation into the Wider Potential of RaaS' report (C6.1), Costain, August 2021, https://project-raas.co.uk

6.5 Further work

6.5.1 More detailed modelling of interruption frequency and duration

For the analysis presented within this report, we modelled the frequency and duration of interruptions based on a set of five years of data from 24 remote substations within the SHEPD licence area. This data was partially pooled together, and statistical models were fit to determine the underlying distributions which describe the likelihood of different frequencies and durations. Experience through the development of this methodology has shown that there is significant scope to refine this modelling over time with additional data, which could potentially include:

- Using more data, including records that cover more historical years as well as a broader range of substations;
- Including variables which might be expected to affect either the frequency and/or duration of interruptions, such as:
  - The length of the circuit that connects the primary to the wider network;
  - Whether there is any redundancy in that connection, including the presence of 11kV back-feed capability;
  - The "remoteness" of the substation, which might affect how easy it is to repair faults, deploy back-up generators, or reconnect customers; and
  - The historical extent of extreme weather events.
- Incorporating subject matter expertise within these models, which can help to accommodate for any shortcomings in the volumes of data;
- Distinguishing between different types of interruption, including:
  - Different causes (if relevant), such as storms vs asset condition;
  - Clusters of related interruption, for example as presented in the Islay data for 2019;
  - Faults that occur on the transmission system.

6.5.2 Modelling interruption costs under future energy scenarios

The worked example of the valuation methodology presented in this report used historic data about each substation but did not include any accounting for how patterns of demand could change in the future. This would be complex, but we expect it would be entirely possible to modify the representation of demand to represent future network requirements, including increased uptake of electric vehicles and heat pump, increasing generation from distributed energy resources, and changing energy usage behaviours. Potential sources of information here include LTDS figures and DFES projections, with further tools being developed through other innovation activities (such as the forecasting tool created for the LEO and TRANSITION projects).

The simplest approach would be to "overlay" profiles for new technologies on top of the historic demands, and then use the aggregated profiles as the basis of the probabilistic simulation. Much of the complexity would then lie in ensuring that the coincident values of the different types of profile are credible, and that they make sense with respect to different daily and annual cycles, relationships

with temperature etc. For example, there have been some recent efforts to explore the impact of future electrified heating on system capacity adequacy, drawing on data from the gas networks[42].

A further challenge would be accounting for different VoLL figures associated with interruptions to different technologies, which could be very dynamic and complex. For example, the disutility associated with interruptions to EV charging demands could be highly variable due to the way that such loads can be time shifted. If the interruption occurs and is addressed overnight and does not affect a customer's EV state of charge when they want to use the vehicle, then the disutility may even be zero. However, if the interruptions impair charging demand and prevents a planned journey, then disutility could be very high.

6.5.3 The relationship between payments and battery behaviour

Section 4 set out that the ability to derive an optimal schedule of payments at present is limited due to the lack of knowledge that a DNO has about how their payment structures will affect RSP decisions, including considerations regarding reserved capacity for RaaS and participation in other flexibility markets. Within the RaaS NIC project, it is understood that these interactions are being investigated through other project activities, such as those to be reported in the RaaS 'Optimisation Assessment for RaaS Battery Operation' report[43].

During the future application of RaaS, one option here could be for a DNO to undertake their own analysis of potential participation in other markets. This would allow for testing of different RaaS payment structures against other competing flexibility services to determine how the RSP might behave with, for example, varying levels of fixed, availability and utilisation payments and penalties.

An alternative would be to carefully track this during early procurement rounds for RaaS and respond accordingly to any information that becomes apparent through engagement with potential RSPs. It seems clear, however, that in the long run, it should be beneficial for a DNO to have this capability internally to aid decision making about RaaS services, as well as other flexibility services.

6.5.4 Probabilistic predictions of state of charge requirements and interruption risk

One option for forecasting set out Section 5 was the use of probabilistic forecasts of state of charge requirements. These are expected to be more onerous to develop and produce than forecasts based on the empirical distributions of segmented historic data, but there is a growing body of literature and open-source tools that could be employed to support this[44]. There are likely to be some unique challenges associated with adopting such forecasts for distribution networks, particularly related to the length and quality of the demand datasets to be used for the production of forecast models, and the potentially high concentrations of embedded generation. Nevertheless, testing the feasibility of producing such forecasts would be worthwhile, particularly as there would be some interesting and challenging questions to consider about exactly how the forecasts could and should be used once produced.

Another interesting avenue of exploration would be the testing of models to dynamically predict the probability of outages occurring, particularly weather-based outages due to extreme high winds and lightning. This would probably require high quality outage data for many locations, together with a

[42] Deakin et al (2021) "Impacts of heat decarbonization on system adequacy considering increased meteorological sensitivity" www.sciencedirect.com/science/article/pii/S0306261921006802
[43] RaaS 'Optimisation Assessment for RaaS Battery Operation' report (E4.2/E4.3), E.ON, September 2021, https://project-raas.co.uk
[44] TNEI is exploring the production of probabilistic forecasts for the transmission network in an ongoing NIA project with NGESO.

bespoke model which can then integrate this data with any necessary subject matter expertise about the causes of faults. High-quality short-term weather forecasts would also be required, along with dynamic lightning risk estimates. Such information is increasingly becoming available[45].

6.5.5 Updating the project's GB-level business case

This report has not gone as far as to completely update the methodology for assessing the GB-level business case for RaaS, primarily due to two key sets of assumptions being unavailable during the period the work was being completed:

- Detailed information about the number of sites where the RaaS concept could be applied across the entirety of GB; and
- Financial figures about the cost of procuring the service.

As further information on these aspects becomes available, a complete update of the project's GB-level business case would be possible. This could use the methodology adopted within the submission to Ofgem (which may be more appropriately deemed a "cost-effectiveness analysis"). However, it may also be a more appropriate option to use the valuation methodology presented in this report to determine the value of RaaS for many substations across the country and, as described under Section 6.5.2, to consider how these would change under different future energy usage scenarios.

[45] www.lightningmaps.org displays the location of lightning strikes in close to real-time

Appendix A: Map of DNO licence areas