LCNF Tier 1 Close-Down Report

Trial of Orkney Energy Storage Park
SSET1009

Prepared By

Document Owner(s)	Project/Organization Role
S Reid	SSEPD

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Executive Summary

Project scope

The Trial of the Orkney Energy Storage Park is a follow on to the Tier 1 project The Orkney Energy Storage Park SSET1007[1]. That project created the necessary commercial incentives to encourage third party Energy Storage Providers (ESPs) to install an Energy Storage System (ESS) on Orkney. This follow on project looked to link the ESS to the Active Network Management (ANM) system previously installed on Orkney in order to facilitate a commercial investigation into the UK energy markets and how ESSs could interact with these markets in order to improve the business case for ESSs.

Aim

The principle aim of the project was to better understand the energy markets open to a distribution network connected ESS.

Activities

The main activities for this project were to:

- Enter into a commercial contract with an ESP to provide electrical power flow constraint management services;
- Modify existing generator and energy storage ANM interface to allow import requests to be sent to the ESS by the network operator;
- Facilitate the connection of an ESS to the distribution network in Kirkwall;
- Operate the contract over the project duration; and
- Summarise the different markets accessible to the ESP during the project.

Outcomes of the project and key learning

The main outcomes of the project were:

- A good understanding of the variables affecting the business case for a distribution network connected ESS ;
- How these variables could be manipulated to make the business case positive; and
- A good understanding of the safety case for a Lithium Ion grid scale ESS.

Conclusions and future work

The project has been a success as the business case behind the deployment of ESSs has been understood with the key sensitivities identified. The main conclusion from the project was that the business case for the battery would be positive, provided that a number of conditions were met. These conditions are: the battery should be commissioned at a later date; its life should be correctly sized:

[1] http://www.smarternetworks.org/Files/_Project_Completed__Conclusions_and_Closedown_Report__130204145313.pdf

- It should be located in the right place to optimise Transmission Network Use of System (TNUoS) Charges avoidance payments; and
- be charged appropriately cost reflective Distribution Use of System (DUoS) capacity.

Having identified these sensitivities as the crucial factors affecting the business case of a potential constraint management service, Scottish & Southern Energy Power Distribution (SSEPD) have taken this forward into a further investigation, using Business as Usual (BaU) funding, to tender for constraint management services from third parties in their Southern Energy Power Distribution license area in order to keep the network within tolerance, whilst deferring larger scale network reinforcement.

Intellectual property

The project made use of products and services available on the market on commercial terms. It did not require the development of new products and as such no Relevant Foreground intellectual property (IP) has been registered for this project. Relevant products and suitable alternatives are available on the market.

The main benefits and knowledge delivered by the project relate to learning around ESSs accessing various energy markets and safety appraisals relating to ESSs, particularly Lithium Ion technologies. Details necessary to allow the project to be replicated by other GB Distribution Network Operators (DNOs) are set out in this report. Any additional information required can be requested through future.networks@sse.com.

1 Project Background

The problem that led to this project was that the 33kV network on Orkney had reached its generation connection limit using traditional system planning methods. To connect further generators, Active Network Management (ANM) had been used to monitor the network constraint points and to control those generators connected through ANM to keep the network within limits. This allowed more generators to connect but meant that their export capability was subject to constraint actions by the ANM. The project aimed to use the ANM functionality to instruct a third party ESS to provide a service to SSEPD by importing excess energy rather than reducing other ANM connected generators export. In effect the ESS was able to deconstrain some of the generation constraints affecting the ANM generators.

Further to this localised problem this project also looked to better understand the role that storage can play, as well as the business case, when installed on the distribution network allowing future storage contracts to attract cheaper bids. The principle could ultimately be applied to other distribution ancillary services e.g. reactive compensation or standby generation.

Previous work: A Registered Power Zone (RPZ) has been established on Orkney, in 2009, using a technology known as Active Network Management to facilitate the connection of new renewable generation onto a constrained, or technically ‘full’, 33kV network. The technology works by monitoring the constraint points on the network in real time and controlling generator export to ensure those constraints are not breached. Further to this, an earlier Tier 1 Project has also been completed, the Orkney Energy Storage Park (SSET1007), this created the necessary commercial incentives to encourage a 3rd party Energy Storage Operator to install an ESS on Orkney. A tender process selected the most economically suitable bid for installation on Orkney.

This project was aimed principally at understanding what commercial markets are open to ESPs that are located on distribution networks.

To facilitate this investigation, SSEPD entered into a commercial contract with the ESP selected in the previous Tier 1 Project allowing them to locate on Orkney and alleviate network constraints. The ESS was sent signals by the existing ANM scheme requesting absorption of excess renewable energy that would otherwise be stopped from generating onto the network. The contract allowed them to run their system commercially with the emphasis placed on them to increase their income by targeting other revenue streams, i.e. STOR or arbitrage. At the end of the project the various markets accessed by the ESP will be shared with SSEPD in order to generate the required learning.

1.1 Budget and Project Timescales

The project was scheduled to last from June 2012 until March 2015 with a total budget of £1.51M.

2 Scope and objectives

The scope of this project is to better understand what commercial markets could be entered into by ESPs operating their systems whilst connected to a distribution network.

Objectives:

1. Enter into a commercial contract with an ESP to provide constraint management services
2. Modify existing generator and energy storage ANM interface to allow import requests to be sent to the ESS
3. Facilitate the connection of an ESS to the distribution network in Kirkwall
4. Service the contract over a 3 year period
5. Summarise the different markets the ESP has managed to access during the project

3 Success criteria

For this project to be a success the final report will have a minimum of an understanding of one other market, aside from the constraint management market, that ESPs can access and generate income from.

4 Details of the work carried out

4.1 Method trialled

Traditionally generator connections are firm in nature in that they allow generators to connect, if the network is intact, and export unrestricted. However where network capacity is exhausted, it is possible to allow non firm connections that are restricted in real time using ANM. This benefits the generators in that they are able to connect in a shorted time scale for a reduced cost, which they then balance against the potential reduced export capability to understand which the most favourable economic solution is. If the generator situation changes in the future then they may want to make their connection firm, which in turn would cost them and possibly the wider UK customer costs.

This project looked to implement a commercial alternative where the DNO specified the nature of the constraint that required management in order to identify a supplier who could manage that constraint on their behalf. Once a suitable party was identified then the required service, and the associated commercial terms and conditions, could be setup and managed accordingly through a service contract. This could allow the DNO to meet their obligations as a network operator, whilst minimising the costs to the company and the wider UK customer base and at the same time avoiding the risk of installing assets, which may become stranded if the constraint driving the scheme were then to disappear through natural network load change.

4.2 Trialling methodology

The following section lays out the steps and key decisions taken when deciding how to deliver the project aim.

4.2.1 Supplier Identification

The first task was to identify an ESP who could provide the constraint management service being used to drive out the commercial learning. The previous Low Carbon Network Funded Tier 1 Project, SSET1007 the Orkney Energy Storage Park, ran an open tender, using a bespoke contract created by SSEPD, to understand the status of the constraint management service market at that time. The process and the number of parties at each stage can be seen in figure 1[2] below.

Figure 1 - Parties Involved in Each Part of the Procurement Process

The process started with 129 different parties being asked to quantify their abilities in delivering the service through any particular method so we established a position where we were technology agnostic. Of these 129 parties, seven were invited to submit a full tender proposal for assessment, which was then assessed from a safety, commercial and technical point of view in order to determine who was best placed to gain the contract. The successful bid was identified as a partnership between Scottish & Southern Energy Generation (SSEG) and Mitsubishi Heavy Industries (MHI). MHI supplied a 2MW 500kWh Lithium Ion containerised system which SSEG installed, commissioned and operated. Following the appointment of the successful party, focus was shifted to establishing the contract and starting work on site on Orkney to install the ESS.

4.2.2 Constraint Management Contract Implementation

Through the previous project, SSET1007 the Orkney Energy Storage Park, a constraint management contract was created as nothing previously existed that was judged as being fit for purpose. In order to do so Baringa Partners were appointed to advise on potential terms as they had good experience of the existing ancillary service markets. Once the terms had been agreed then the SSEPD Legal team drew together the contract to be used as the basis for tender exercise. Getting the terms correct was essential as the aim of the project would be best delivered by enabling free market access by the ESP. Making the terms too restrictive could result in no other markets being accessed and the project losing out on crucial learning. The key terms were determined to be: the timing of the constraint management service requirement; and the ancillary service market access ability.

The timing of the service requirement was important because some times of the year were more likely to result in the constraint manifesting itself on the network than others. In addition to the time of year factor the time of day factor was also important. To understand this it is important to understand the nature of

[2] PQQ – Prequalification Questionnaire

ITT – Invitation to Tender

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the constraint, which was a thermal constraint, i.e. power flows on the Orkney 33kV network could exceed operational limits resulting in adverse effects on customers and DNO assets if not managed accordingly. Studies showed that the constraint tended to be more apparent when there was a certain level of generation being exported to the network coupled with reduced demand to absorb the energy locally before it got to the network constraint points. The timing of this constraint tended to cover April through to September, not because these are the traditional windy months but rather because there is a sufficient wind and a time of year when there is reduced demand. As such, the contract incorporated a monthly factor which allowed the payments to be multiplied by a value that either increased or decreased the total payment depending on the time of year, as can be seen in Table 1 below. This was aimed to clearly show when the service would be needed and create a greater incentive for the ESP at the relevant times.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Aug	Nov	Dec
Factor	0.6	0.7	0.6	1	1.1	1.5	1.4	1.3	1.2	0.9	0.6	0.8

Table 1 - Monthly multiplication factors

When it came to the time of day, studies showed that the constraints tended not to occur when demand was high, with this tending to coincide with the morning and evening times, which was a result of excess generation power flow not being absorbed locally before reaching the network constraint points. At the same time ancillary services are more likely to be required to help the System Operator (SO) when system peaks are occurring, which typically would be across the same times. The contract thus put in place a series of availability periods for the constraint management service to allow the ESP to be able to access other markets. Details of the timings can be seen in Table 2 below.

Availability Period	Time Period
AP1	00:00:00 until 07:30:00
AP2	09:00:00 until 17:00:00
AP3	22:00:00 until 23:59:59

Table 2 - Availability Periods (AP)

The final crucial term was the accessibility of other revenue streams, which tend to come from the ancillary services markets. Making the constraint management service mandatory would have restricted the ESP to a single revenue stream and little would have been learned. Instead the service provision was not made mandatory in order to determine how a free market mechanism would mean for the service, i.e. would the ESP manage the constraint or do something else completely different due to it being more lucrative. This would allow a view to be taken on the level of reward attached to the service and how that

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compared with other revenue streams. In addition this did not leave the network subject to overloads as the ANM system always ensures that network operational limits are not breached. This would not necessarily be the case for future deployments as they may not have ANM deployed in the same locale.

4.2.3 Site Works

Due to the method chosen to deliver the project outcomes, i.e. contract management rather than asset owner/operator, the responsibility for the installation and commissioning of the asset fell to SSEG and MHI. However SSEPD did still help facilitate the build by leasing land to the ESP, feeding into the engagement with the emergency services and creating the necessary data interface between the ESS control system and the ANM. Details of this are covered in Section 5.

4.2.4 Commercial Investigation

Whilst the ESS was being constructed, Baringa Partners were again engaged in order to undertake the commercial investigation. Their engagement was split over three phases:

- Phase one to understand the existing markets at the beginning of the project using the name plate technical parameters of the ESS and incorporating this in a business case;
- Phase two was an update of the business case using measured technical parameters for efficiency, transfer rate and storage capacity, all of which were recorded during a period of testing by the ANM suppliers, Smarter Grid Solutions; and
- Phase three was a full update of the business case using measured parameters gathered through the trial as well as the state of the markets at the time of project close.

Through all three phases, the pricing tendered, as part of the procurement process to identify the ESP, was kept confidential as the details were commercially sensitive to the MHI/SSEG partnership. In place of the tendered price and the costs for installing and operating an ESS, publicly available literature was used[3]. The reason for this was that the system costs were hidden to the DNO as they had no involvement with the technical aspects as they were using a commercial approach, i.e. servicing a contract rather than buying assets.

4.2.5 Contract Operation

Whilst the commercial investigation was ongoing, the ESS was installed and commissioned and once this was completed all that remained was to service the contract and gather the results. Operation of the contract involved the ESP submitting monthly invoices to SSEPD, who in turn extracted the data gathered

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[3] Bloomberg New Energy Finance, (2011), Grid-Scale Energy Storage: State of the Market
McKinsey and Company Insight (July 2012)
"Grünewald *et al.* (2011) -The role of large scale storage in a GB low carbon energy future" An average of multiple sources
Element Energy, Cost and Performance of EV Batteries for The Committee on Climate Change (March 2012)
UK Power Networks (UKPN) LCNF Tier 2 SNS

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from the metering circuit breaker and passed it through a billing verification tool. This ensured that the invoices were in line with the agreed figures for the level of service provided and at the same time service provision failures could be identified. These were then fed back to the ESP to allow them to improve their service and thus be able to earn more revenue.

It is worthwhile mentioning at this stage that the contract was due to be serviced over three years but due to delays in the delivery and installation of the system the time frame was reduced to 31 months. Details of this are discussed in Section 7.

5 The outcomes of the project

The following section will set out the key outcomes in relation to the project objectives.

5.1 Enter into a commercial contract with an ESP to provide constraint management services

The first main output of the project was to put a signed agreement in place between SSEPD and the ESP, which sought to reinforce the use of the commercial constraint management market. This was signed off by the two main contracting parties, SSEPD and SSEG, on the 31st of August 2012. The contract itself was split into two main parts with the second half covering the technical terms and conditions associated with the required service. For full details of the contract, the terms and the rationale that led to it then please refer to the closedown report for SSET1007 Orkney Storage Park.

5.2 Modify existing generator and energy storage ANM interface to allow import requests to be sent to the ESS

5.2.1 Interface Design

When originally designed, the Orkney ANM system only controlled the renewable generator output in conjunction with monitoring of power flows on the local Distribution network. However, what this project required was for the ANM system be modified to allow an ESS to be interfaced and controlled in a specific manner depending on whether a constraint management service was being provided or not. The basic premise was that the ESS would be instructed to import if they had made themselves available and if there was a need, i.e. an active constraint was in progress in the same operational zone as the ESS.

In order to implement this, Smarter Grid Solutions (SGS), the ANM supplier, put together a Design Specification covering how the system would operate and the main components feeding into its operation, as can be seen from figure 2 below. This was an amalgamation of two existing interfaces which were in use on Shetland as part of the Shetland ANM [4]and on Orkney as part of the Orkney ANM.

[4] http://www.ninessmartgrid.co.uk/our-project/shetland-energy-challenge/

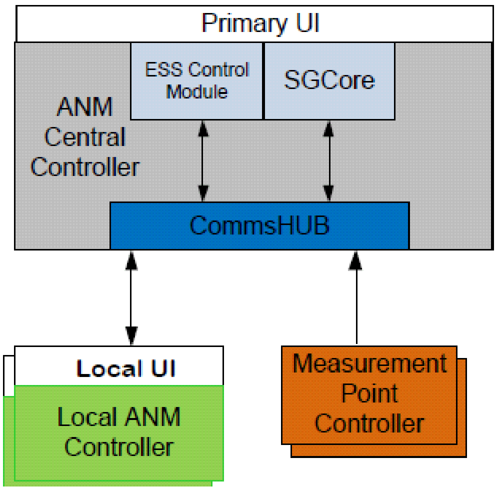

Figure 2 - High Level ESS Control Components

In addition to the component diagram and the requirements covering the interface detailed in Appendix 1, there is also a copy of a diagram showing the full system architecture and the Human Machine Interface screens from the DNO Network Management System. Using these details it would be possible to replicate the function performed by the interface module.

The modification was needed because if the service was being provided then the generator stack position, or the Last in First off (LiFo) stack, defaulted to the bottom. This is because the service aimed to alleviate a generation export so the remedial action was to import energy. Thus having the ESS at the bottom of the stack would allow other generators to be able to export more in addition to the service provided by importing energy that would otherwise not be allowed onto the network. The availability payments were aimed to be part of the compensation for this happening. However if the ESS did not make themselves available for any specific Availability Period (AP), then they were treated as if they were any other ANM controlled generator and were placed at the stack position determined by when they accepted their connection quote.

The final piece of the interface was to ensure that the control room had visibility of the ESS operation, where it was in relation to the rest of the Core Zone constituents on the ANM and have control over the interface to the network.

5.2.2 ESS Control

Whilst going through the connection process it was discovered that the maximum import of the ESS could potentially lead to an overload of a network asset on Orkney. In order to resolve this would have required replacement of a costly asset, which wasn't within the scope of the project. Instead, the ANM system was used to check the crucial load flows and decide whether there was going to be a demand constraint caused by an ESS import. If there was an issue then the ESS would be managed in such a way that the constraint was not an issue.

5.3 Facilitate the connection of an ESS to the distribution network in Kirkwall

The following section considers what SSEPD did to facilitate the installation of the ESS on site in addition to the interface that was explained in Section 5.2

5.3.1 Health and Safety

In order that the project was delivered in a safe and cost effective way, SSEPD aided in the design and installation process primarily by getting involved with the emergency services engagement piece of work. This was for two reasons: to ensure the project was delivered in line with SSEPDs safety stance, i.e. safety is the number one priority; and to ensure that as much could be learned for future Lithium-Ion ESS deployments to help ease construction issues.

In order to do this, the project followed on from the health and safety work completed in SSET1007, the Orkney Energy Storage Park project. During this time, an assessment was carried out, by EA Technology ltd, on behalf of SSEPD, on the tender winners' scheme design to ensure that it held true to the SSEPD safety principles. Using that as a starting point the project then took the original analysis and built that up into a risk assessment of the known failures issues for Lithium-Ion. The publicly available knowledge base to develop this risk assessment was fairly limited at the scale being deployed within the project. The majority of reporting pertained to laptop and phone batteries and their transport. This however changed during the safety assessment portion of the project as two major incidents occurred that were widely reported:

- General Motors battery laboratory explosion[5]
- Boeing Dreamliner battery fire[6]

Prior to these incidents an explosion had not occurred at this scale of ESS so had not been considered a high probability occurrence, however once these incidents came to light then the full assessment process needed to be revised. The project team were engaging with the Orkney emergency services, who had a certain level of concerns due to the novelty of the technology scale and the application, even before the two incidents mentioned above.

To understand the concerns raised by these incidents it is first necessary to understand both the ESS architecture and the failure modes for the ESS chemistry, lithium-ion, of which there are two unlikely, though plausible failure mechanisms:

- Fire; and
- Blast.

[5] http://www.bloomberg.com/news/articles/2012-04-11/gm-lithium-battery-lab-explosion-injures-2-fire-department-says

[6] http://www.bloomberg.com/news/articles/2014-12-02/boeing-s-dreamliner-battery-fire-caused-by-design-probe-finds

Further to these failure modes the other important consideration when looking at L-Ion fires is that in the event of a fire and although it appears to have been satisfactorily resolved, there still exists a potential for reignition once air is reintroduced to the scenario. As such all safety considerations of fires and explosions need to account for this risk when trying to deal with any incident and especially when attempting to enter the affected containers.

The architecture of the ESS was constructed through a series of cells being arranged into modules, which are then fitted into racks. The racks were installed into two of the three containers, with the third container containing the Power Conditioning System. In order for a fire to occur, and assuming that none of the defence in depth precautions were in place, multiple cells would need to fail with the off-gases igniting as each cell failed. The failure method for an explosion would be the same except that the off-gases wouldn't ignite as they were expelled from the cells, rather those gases would need to build up until a certain amount of gas had collected, and then it would need to ignite to cause the explosion. As such if there is a fire then the likelihood of an explosion, which already is very low, would become even less likely.

In order to guard against both these failsafe modes the ESS supplier, MHI, had deployed a defence in depth approach to make sure that the system would not catastrophically fail and if it did, to mitigate the impact. This involved redundancy of the monitoring systems associated with the individual cells, modules and racks to identify any likely failing cells, climatic control and if everything else failed then a Fire Suppression System (FSS) would be initiated. These layers of protection were analysed by EATL who found the risk to be as low as reasonable practicable, with their analysis including an in-depth analysis of the FSS and how it would likely cope with a fire.

The only residual risk was explosion and to understand this it was first important to define the mechanics of an explosion and what the likely effects would be on the local area. With this understood then it would be possible to put in place a method statement that quantified the risks and accounted for these in a reduced risk approach. A report was commissioned by SSEG from Chilworth Technology ltd, a safety consultant company who provide expertise of fire and blast modelling, to cover the effects of such an incident. Chilworth built up a model of the local area and using some key assumptions around fire type and ignition mechanics were able to define the levels of risk attached to the installation. They stated that a fire, although theoretically plausible, would not affect any third party premises and that it could be managed to a safe state. On the possibility of an explosion they laid out the only credible scenario for it occurring, which was a large number of cells failing all at once without ignition until an adequate level of gas had accumulated. For that to happen would require a minimum of 30 minutes with 60 minutes being the more likely timeline.

With the impacted area and the timelines known it was possible to draft a method statement with suitable precautions for identifying the build up of heat, verifying it (without risking reignition) and then understanding the necessary course of action to ensure people were outside the possible affected area. The method statement was then shared with the SSEPD and SSEG control rooms as well as the emergency services so that in the event of an issue all parties were aware of what needed to happen and who was responsible for the various elements of the method statement.

5.4 Service the contract over a 3 year period

Originally the project had aimed to service the contract over 36 months, as this would give the ESP enough time to set up some additional revenue streams. However due to a delay during the previous project, SSET1007, this project suffered a knock on delay that amounted to 5. Details of this can be found in section 8.

The remainder of this section looks at the main activities required when managing a service contract to ensure the service is being provided and that the value being invoiced is linked to the provided service. In order to do this it is important to understand where the data is coming from, what form it takes and then feeding it into a verification process.

5.4.1 Billing Rules

The first consideration for understanding what data needs to be collected and analysed are the rules laid out in the Constraint Management Service Contract. These rules governed what was deemed compliant and non-compliant service provision with the long list included in Appendix 2 Billing Rules along with a diagram explaining the terms, how they are calculated and how they relate to each other. With the rules defined and signed off then it remained to capture the data necessary to test these billing rules. As such the following data points were captured through the ESS and the ANM interface either through direct measurement by Current and Voltage Transformers (CT or VT) or being supplied by the ESS, which was then all passed through SSEPDs Network Management System, Power On Fusion.

Term	Unit
Curtailment Reduction Set-point	kW
Battery Availability	1 = Available, 0 = Unavailable
Battery State of Charge (Actual)	kWh
Battery Power Export	kW
Battery Power Import	kW
Battery Capacity (Nominal Available Capacity) [7]	kWh
Battery Available Import	kW

[7] NAC is a term that is used to understand whether the ESS should be allowed full Availability Payments or Nominal Availability Payments. Full details available in SSET1007 closedown report

Stated Capacity	kWh

Table 3 - Collected Billing Data

5.4.2 Bill Verification

With the rules defined, the data required identified and collected it only remained to devise a spreadsheet tool that fed in one month's data to derive what the amount to be paid was. SGS put the tool together and each month was sent data to calculate how much was owed for the service provided. This figure was then compared against what the ESP had invoiced for and if they were within tolerance then the figure was paid. The reason for the tolerance was that the source of data and the way SSEPD and the ESP calculated the figures, were different. The SSEPD data came from protection CTs and VTs and as such tend to come with a five % error as opposed to metering class equipment which is far more accurate. In this way the bills were verified and then paid as per the original tendered terms and conditions.

5.4.3 Payment Rules Compliance

To understand how the ESS had performed over the course of the project all the data was sent to SGS for them to analyse the ESS performance in conjunction with the contract terms and conditions. Their findings were as follows:

Total APs During Project	Total APs not participated in	Total APs partially participated in	Total APs fully participated in
1824	989	74	761

Table 4 - AP ESS Participation

The first thing to take from this analysis is that the majority of the time, 54%, the ESS was not available for service provision. The reasoning for this can be split into the following reasons:

- ESS unavailable;
- Billing rule non-compliance; and
- Network disturbances;

The majority of the time the reason why the ESP was not paid was because the ESS was not made available for the service. This was for a multitude of system reasons ranging from the ESS requiring a system reset to an ANM system telecoms issues. The system issues were something that the ESP was working on in order to make the system more resilient.

The billing rule failures were due to timings of signals, i.e. notifying the ANM of the system being available and importing when not directed to during the APs. The timing issue was resolved by adjusting when the ESP notified of the ESSs availability for service provision. This resulted in the system notifying the ANM up to half an hour before the start of the AP, which tended to resolve this issue. The other billing issue was the system importing energy within the AP when not directed to by the ANM. This was because the ESS had a minimum state of charge that the manufacturer required so that the life cycle of the battery was not adversely affected. When this failure type was explained to the ESP they rescheduled their ESS import schedules so that no imports happened due to this particular function and improved their service provision rate.

The final reason for the ESS not being available was because of network faults. The 'loss of mains' protection system on the ESS employed a Rate of Change of Frequency (ROCOF) relay, which was initially set too sensitively. These settings meant that for network faults not related to the ESS, the ESS was still being tripped by the ROCOF relay. With this issue identified then it was resolved to the satisfaction of the SSEPD technical authority as well as the ESP.

5.4.4 ESS Validation

The final portion of servicing the contract was to ensure that the system was technically able to provide the service and, whilst doing this, to verify the actual technical parameters of the system. In order to do this SGS developed a test specification that took all the billing rules and stress tested them against the ESS operation by creating four tests:

5.4.4.1 Test 1

- ESS import to full charge at MW rated capacity (2MW);
- Hold at full state of charge for extended period of time; and
- ESS export to full discharge at end of test period.

This test scenario depicts a sustained duration constraint event, which causes the ESS to import at full rated capacity until the ESS is full and no further import is possible. As the constraint event is prolonged the ESS cannot export until there is sufficient export capacity available on the network, i.e. once the power flow at the core zone measurement point goes below the curtailment threshold. When exporting, the ESS is initially limited by the network capacity available, but as more capacity becomes available, the ESS is able to export at its full rating.

5.4.4.2 Test 2

- ESS import to full charge at MW rated capacity (2MW);
- Hold at full state of charge for short period of time; and
- ESS operates at full rated export to full discharge state.

This test scenario depicts a constraint event which is of sufficient duration that the ESS must import until full, however the constraint event is not as prolonged as in Test 1, and after a short period the constraint recedes and network export capacity becomes available, causing the ESS to export. Again, when exporting the ESS is initially limited by the network capacity available, but as more capacity becomes available, the ESS is able to export at its full rating.

5.4.4.3 Test 3

- ESS partial import at MW rating (2MW);
- Immediately followed by short period of export;
- Immediately followed by import at MW rating to maximum capacity;
- Hold at full state of charge for remainder of test period; and
- ESS export to full discharge at end of test period.

This test scenario depicts a period where a short constraint event occurs, however the ESS does not import to a full state before the constraint recedes and network capacity becomes available, allowing the ESS to export. However, before the ESS is able to fully discharge the network constraint re-emerges, requiring the ESS to import. This constraint event is more prolonged than the first, and the ESS is able to fully charge. Once the constraint event recedes and export capacity becomes available, the ESS is able to export to full state of discharge.

5.4.4.4 Test 4

- ESS import to full charge at MW rating.
- Hold at full charge state for short period of time.
- Partial export at less than rated capacity.
- Immediately followed by further import at MW rating back to full capacity.
- Hold at full state of charge for remainder of test period.
- Export to full discharge at end of test period.

This test scenario depicts a period where a constraint event occurs, of sufficient duration that the ESS is able to fully charge. After a short period the constraint recedes and limited network capacity becomes available, allowing the ESS to export. This period of export is only sustained for a short period before another constraint event occurs, requiring ESS full import. The constraint event is prolonged beyond the

ESS reaching full capacity, and as the constraint recedes and network export capacity becomes available, the ESS is able to discharge.

5.4.4.5 Test Results

Below are a series of graphs that demonstrate where the values in Table 5 came from with an explanation of the values following the table.

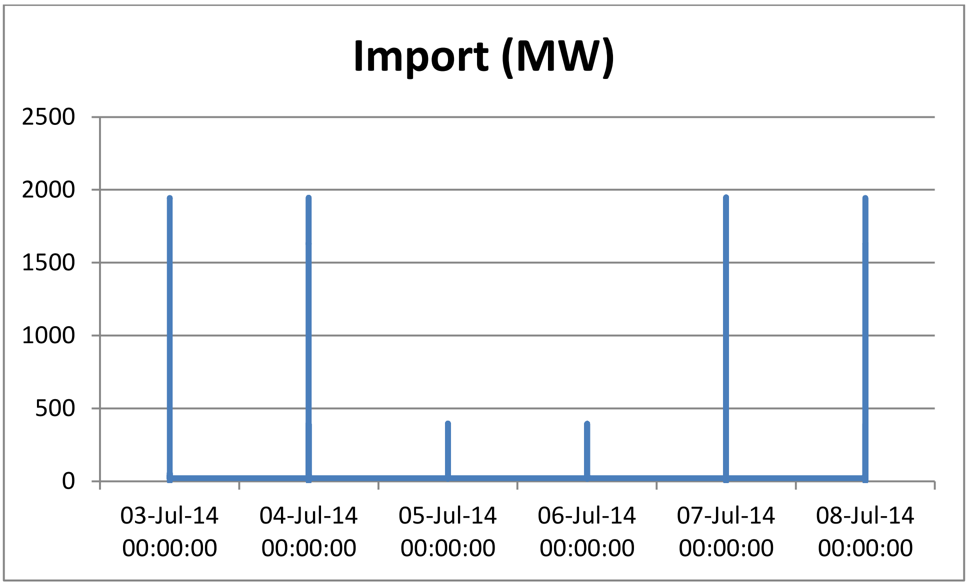

Figure 3 - Measured ESS Import Values

The above figure shows that the ESS never imported up to its 2MW value but rather was recorded at no greater than 1.949 MW for all four tests. The reason for there being more than four import values is that tests three and four had more than one import action associated with it.

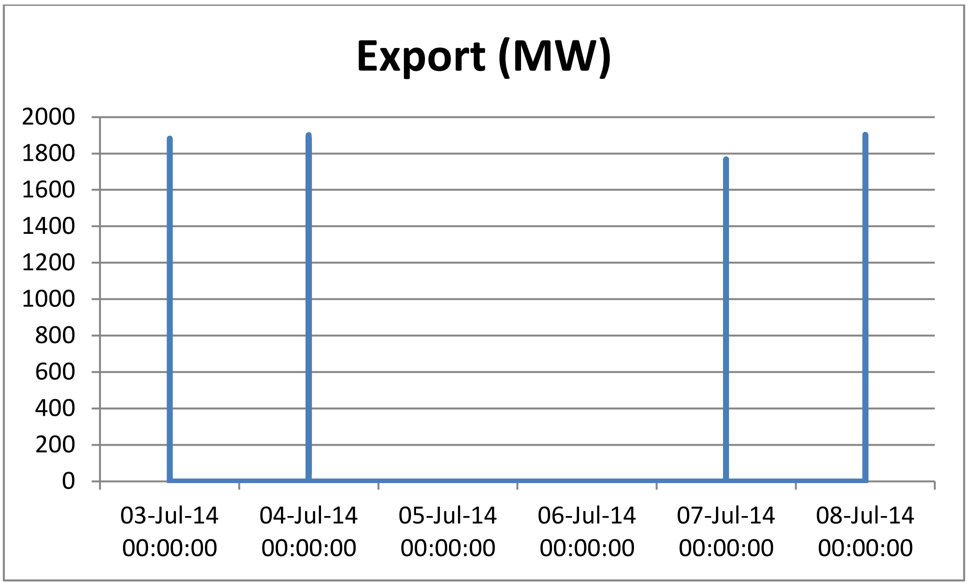

Figure 4 - Measured ESS Export Values

The above figure shows that the ESS never exported up to its 2MW value but rather was recorded at no greater than 1.9MW for all four tests. The reason for there being more than four export values is that tests three and four had more than one export action associated with it.

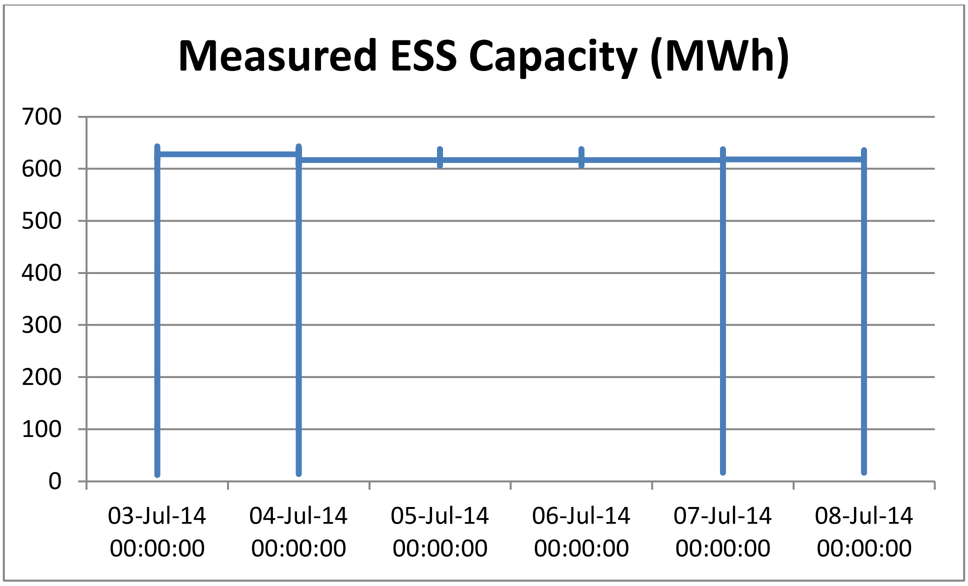

Figure 5 - Measures ESS Capacity (MWh)

The figure above shows that the battery capacity was in fact greater than the 500KWh as was billed during the procurement phase. For the remaining values shown in table 5, the above values were used to calculate the remaining values alongside the associated timeframes.

The testing of the ESS revealed the following interesting points relating to ESS operation:

1. The ESS never reaches a condition where the stated capacity (available to import more energy) is 0 kWh. The minimum observed capacity is 12 kWh, though in fact the ESS does not have available import capability, so is effectively full.
2. Across several tests, ESS import was not identified until one minute after the first nonzero curtailment reduction set-point. This may be due to delay in the ESS initiating import or export actions; however this delay may also be due to the sampling within the OSIsoft supplied data historian, Plant and Information, that logs operational data.

In addition the overall test results were also used to define the actual technical parameters for what the ESS could deliver if required. The table below shows these measured values.

Maximum Charge Rate	1.9 MW
Maximum Discharge Rate	
Maximum Storage Capacity	0.625 MWh
Minimum Storage Capacity	0.012 MWh
Charge Time	23 minutes
Discharge Time	29 minutes
Cycle Efficiency	78.4 %[8]
Auxiliary Power Supply Load	24.52 kW

Table 5 - Measured ESS Technical Parameters

In order to better understand these technicalities, MHI, the supplier, were asked their opinion about the test results. Their response for the first point was that charging of the ESS is automatically stopped once the individual cell voltages reach 4.13 V or if the state of charge has reached its capacity. With the system being new it meant that the cells were newer and were able to accommodate higher voltages, as is a feature of most battery technologies, and thus the voltage was the signal to stop the charge/discharge action. In the future this will change because the cells will start to wear and be unable to reach the same voltage levels. At that point the state of charge mechanism will be what stops any charging and

[8] This figure covers full round trip efficiency and includes auxiliary loads necessary to keep the ESS in operation

discharging. This does not mean that the ESS capacity will reduce over time as MHI have over specified the ESS so that in effect, when it is new, it would technically be able to provide around 625kWh of capacity. Thus when the system is nearing the end of its useful life it can still deliver the 500kWh capacity specified at the tender stage.

For the second point the MHI explanation was that the time series was too big, one minute resolution, to see the change in action. They clarified this by performing 10 second analysis of the data and it showed the system operating and responding within expected timescales.

When it came to the measured parameters in Table 5 the first thing to notice was the maximum charge and discharge rates were 100kW less than the name plate rating. When the MHI were asked about this their explanation was the maximum charge was limited to less than 1.9 MW due to the sizing of the transformer. As it was sized at 2 MW and the maximum auxiliary load was 100 kW then the rating of the transformer, 2 MW, wouldn't be exceeded. MHI confirmed that the system itself was capable of completing a 2 MW discharge also, suggesting that the 100kW gap was caused by a combination of metering inaccuracy and the inclusion of the auxiliary load. It should be noted that to ease the complexity of the business case model developed by Baringa as part of the project, some of these values were simplified. Details of these are contained within the knowledge artefacts detailed in Section 12. The final point to note in the measured parameters was that the system took longer than the badged 15 minutes to charge and discharge. This is partly due to the parasitic load and the fact that the capacity of the ESS was larger than badged and as such took longer to fill or empty.

5.5 Summarise the different markets the ESP has managed to access during the project

The main purpose of this project was to better understand the energy markets open to distribution network connected ESSs through the deployment of a physical ESS. This aim relied on the ESP actively targeting other revenue streams and putting the necessary contracts in place to allow multiple revenue streams to be targeted. However as things turned out the ESP did not engage in any other markets. When this was highlighted and challenged, the ESP admitted that although the constraint management service contract did not cover the full value of the project, the overheads associated with actively engaging with those markets made the prospect uneconomic. This is interesting learning in itself as it shows that a third party, SSEG, who already had an energy market presence, considered it impractical to make the multiple revenue model work in an economic manner, given the location of the in Orkney.

In order to extract the maximum learning from the project, and to achieve the required learning in terms of multiple revenue streams, Baringa provided the theoretical business case for the installation including what it would take to make the installation economic. This section will lay out the learning gleaned through this modelling work.

5.5.1 Markets Available to ESSs

ESS assets can provide a broad range of valuable services to multiple parties involved in the transmission, distribution, supply and balancing of electricity. These can be broadly classified as ancillary balancing services contracted with the SO, avoided use of system charges contracted directly with suppliers and generators (or through an aggregator), and more locational network support services contracted with DNOs (to alleviate locational constraints as is the case at Orkney). ESS assets can also access electricity arbitrage opportunities, capturing the value of price differentials and peak power price volatilities.

ESS can be provided by a wide range of technical solutions including pumped hydro storage, electrochemical storage, flywheels, compressed air, gravitational storage and other emerging and novel technology solutions. These technologies can have a wide range of capital costs and performance characteristics. As such, some technologies are more suited to providing particular ancillary services than others.[9]

These services may be mutually exclusive and normally cannot be offered simultaneously. For example, some ancillary services require that capacity be available during fixed "exercise windows". An asset operator choosing to offer multiple services in a given window could be exposed to penalties if one or more of the obligations were not met.

Capitalising on certain revenue opportunities may also impair other opportunities in the future. For example, to capture arbitrage revenues the asset would be required to cycle (charge/discharge) more frequently than for the provision of some ancillary services, accelerating the degradation of the battery and reducing the capacity available to capture potentially more lucrative revenues in the future. As such, the contracting and dispatching strategy of the asset is critical if the full life-time value of the asset is to be realised.

Each of the ancillary markets that are available to the Orkney Storage Park (SP) are discussed in Table 6.

[9] For example, the standing energy losses and discharge capacity degradation of electrochemical energy storage assets (batteries) increases as the asset is utilised, as opposed to mechanical energy storage assets (pumped-storage) where utilisation does not have a profound effect on capacity degradation and standing losses. As such, mechanical energy storage assets are more suited to capturing revenue streams that require high frequency cycling of the asset such as electricity arbitrage.

Value stream	Description
Local security or constraint management	Provision of capacity in a specific location to manage import or export constraints (i.e. at times of peak local demand or at times when local generation would otherwise be curtailed off respectively).
Short Term Operating Reserve (STOR)	STOR is capacity that National Grid retains on stand-by that can be called on to generate export within four hours of instruction (with a focus on <20min). The STOR service retains spare generation capacity (or demand reduction) on stand-by during certain hours of the day (typically periods when demand is changing rapidly). STOR is procured as a hedge against short term procurement of reserve in the Balancing Mechanism.
Triad avoidance	In April of each year, each licensed electricity supplier is charged TNUoS for the peak load it imposed on the grid during the three peak half hour demand periods in the previous year, the Triad periods. Embedded generation allows electricity suppliers to reduce their TNUoS charges by reducing consumption during the Triad periods.
Capacity payments	In 2014, the first auction under the new Capacity Market took place for delivery in 2018/19. Trial auctions involving demand side response and storage will begin in 2015 for delivery in the following year. Successful parties will receive capacity payments, based on the auction clearing prices, but will be penalised for not being available during periods of system stress.

Table 6 - Available Ancillary Revenue Streams to Orkney ESS

5.6 The Orkney Energy Storage Park Business case

This section considers the business case for the Orkney Energy Storage Park by determining a target revenue for the asset on the basis of the need to cover operating expenditure and produce a reasonable return on upfront costs over the lifetime of the asset. A combination of services is identified that maximises the asset’s potential revenue (accounting for any mutual exclusivity). The annual revenue target and potential revenue are then compared to determine whether the project is economically viable. The technical parameters used for this work are as recorded through the testing by SGS as described in Section 5.4.4.5

5.7 ESS asset capital and operational costs

For the purpose of this analysis, publicly available information on battery costs has been used, rather than using actual costs incurred for the innovation project, in order to be more representative of battery costs in general. Lithium-ion battery costs were sourced from publicly available and peer reviewed literature[10]. On this basis, a cost of £650/kWh is assumed for a battery installed in 2013. In order to account for expected degradation over time, the capacity of the battery when initially commissioned had a capacity of 0.816MWh, which would correspond to a cost of **£530,400** using this value.

To calculate the annuitised capital cost of the asset a number of financing assumptions have been made. These are based on published literature and are summarised in Table 7[11].

Depreciation (%)	18.00%
Cost of Equity (pre-tax Real %)	12.50%
Debt Interest Rate (pre-Tax Real %)	7.50%
Debt Loan Tenure (yrs)	3
Gearing	70%
Weighted Average Cost of Capital (WACC) (pre-tax real %)	7.90%

Table 7 - Battery Financing Assumptions

Given that the planned duration of the innovation project was three years, this is the assumed financing period. For each of the three years of asset life, the annuitised capex cost for the Orkney battery would be **£228,500/annum**. It should be noted that the actual technical life of a commercial battery is expected to be longer than this and this would reduce the annuitised capex cost. This sensitivity is explored in Section 5.15.

The battery incurs costs associated with the power that it consumes. Although the battery both imports and exports power, it is a net consumer of power for two reasons:

- With a less than 100% cycling efficiency, the battery imports more power whilst charging that it exports whilst discharging. Given that the number of cycles required to offer STOR and Triad avoidance is relatively small, the cost of additional consumed energy associated with this cycling inefficiency comes to just **£800/annum**[12].

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[10] See Appendix III for cost assumptions and references

[11] Depreciation assumptions are taken from the HMRC "Capital allowances investment scheme" website[11] and financing assumptions from Ofgem's "Electricity Distribution Price Control Review Final Proposal – Allowed Revenues and Financial Issues" document (http://www.hmrc.gov.uk/capital_allowances/investmentschemes.htm

[12] Note that the modelled revenues for these services assume 100% efficiency, with the cost associated with the true efficiency added to the revenue target

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- Independent of the cycling regime, the battery and associated systems consume 25.5 kW of power. This is both to recover the battery's tendency to self-discharge, cover any standing loses, and to power the ESS asset's auxiliary systems (e.g. temperature regulation). This results in a cost of **£8,600/annum**.

Total "self-discharge" losses therefore amount to **£9,400/annum** in 2013, falling to **£8,100** in 2015 primarily as a result of a drop in wholesale prices over the period.

In addition to net power consumption, the ESS asset will incur other costs associated with operation and maintenance (O&M). These are site and company specific. Based on experience of similar projects, it is assumed that opex not related to battery efficiency or powering auxiliary systems amounts to 8% of the capex: **£42,400/annum**.

5.8 DUoS charging

In addition to the O&M costs identified above, there are costs associated with accessing the distribution network in the form of DUoS charges which change each year and are intended to be broadly reflective of the cost that an asset imposes on the distribution network. The charges imposed therefore vary depending on a number of factors, including:

- The region where an asset is sited
- The voltage level at the point the asset is connected to the grid
- The type of asset (e.g. whether a generator or a load)

There is no specific consideration for storage assets under the DUoS charging methodology. For the purpose of this business case, it is assumed that the asset has a separate import and export meter, and incurs DUoS charges against each independently. The relevant 2015 charges for the asset sited in the Scottish Hydro Electric Power Distribution (SHEPD) region are summarised in Table 8 with the corresponding time bands shown in table 9. Note that the locational issues for DUoS charging and also TNUoS avoidance revenues are explored in Chapter 5.16.2.

	Unit rate 1 p/kWh (red/black)	Unit rate 2 p/kWh (amber/yellow)	Unit rate 3 p/kWh (green)	Fixed charge p/Meter Point Admin Number (MPAN)/day	Capacity charge p/kVA/day
HV HH Metered	2.216	0.836	0.243	241.07	12.27
HV Generation Non-Intermittent	-1.542	-0.571	-0.143	298.57	

Table 8 - Applicable SHEPD DUoS Charges[13]

[13] https://www.ssepd.co.uk/Library/ChargingStatements/SHEPD/

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Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (Including Bank Holidays) All Year	16:30 - 19:00		
Monday to Friday (Including Bank Holidays) All Year		09:00 - 16:30 19:00 - 20:30	
Monday to Friday (Including Bank Holidays) All Year			00:00 - 09:00 20:30 - 24:00
Saturday and Sunday All Year			00:00 - 24:00

Table 9 - SHEPD DUoS Time Bands

The overall effect of this charging regime depends in part on the amount of cycling that the battery undergoes, since the DUoS unit rates are a function of import and exported energy. The respective contributions of the unit rate, fixed charge and capacity charge are broken down as follows:

- The asset incurs (or receives) the unit rate when charging or discharging. Because of cycling inefficiency and self-discharge, the asset has to charge more than it discharges. For the purposes of this exercise, we assume that it does so during the Green Time Band, so the net cost is relatively low. In 2013 the net cost is **£460**, but this falls to **£210** in 2015 reflecting a fall in the unit rate for loads and an increase in the unit rate payment made to generators;
- Assuming the fixed charge is imposed twice (once for the asset's demand MPAN and once for its generation MPAN), the cost would come to **£1,700/annum** in 2013, rising to **£1,900** in 2015.
- Assuming the capacity charge is imposed on the charging capacity of the battery, this would impose by far the most substantial DUoS cost on the battery project, adding a cost of **£63,500** to **£78,400** per annum between 2013 and 2015. Whether this is an appropriate charge for a battery is considered in Section 5.17.3

Total DUoS costs therefore amount to **£64,900** to **£80,500** per annum between 2013 and 2015.

5.9 CCL, RO, CfD & Small Scale-FIT Obligation Costs

As a consumer of electricity, the asset is also potentially subject to "green levies" imposed on consumers or suppliers, such as:

- Climate Change Levy (CCL): a tax on UK business energy use with the aim of providing an incentive to increase energy efficiency and to reduce carbon emissions
- Renewables Obligation (RO): requiring licensed UK electricity suppliers to source a specified proportion of the electricity they provide to customers from eligible renewable sources, demonstrated through the purchase of Renewables Obligation Certificates (ROCs).

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- Contracts for Difference (CfDs): CfD generators will sell energy into the market but receive a top-up from the market price to a pre-agreed 'strike price', with the cost being passed through to consumers.
- Small-scale Feed-In Tariffs (ss-FIT): support organisations, businesses, communities and individuals to generate low-carbon electricity using small-scale (5MW or less total installed capacity) systems

These levies[14] are imposed on electricity suppliers in order to recover costs associated with subsidising renewable generation. Charges are imposed in proportion to the volume of electricity consumed by the suppliers' customers. Typically, suppliers will then pass these costs through to their customers.

Although a decision has not yet been made yet, it is possible that the Orkney Energy Storage Park would face these charges via its Power Purchase Agreement on the basis that it is operating as a load for part of the year[15]:

- The CCL is set at £5.54/MWh for Industrial and Commercial consumers from April 2015, and was at a similar figure in 2013 and 2014. This results in a cost to the asset of **£1,500/annum**.
- Based on DECC's estimates, the cost of the RO, CfD and FIT levies between 2013 and 2015 has been between £10/MWh and £15/MWh. Collectively, these impose costs of between **£2,900/annum** and **£4,300/annum** over the three-year life of the asset.

5.10 Revenue target summary

The overall annual revenue target combines the annuitised capex with the site opex, DUoS charges and green levies. These are summarised in Table 10 below.

Annual revenue target (2013 £ real)	2013	2014	2015
Annuitised capex cost	228,494	228,494	228,494
Cycle efficiency, self-discharge & auxiliary power cost	9,351	9,182	8,050
Other site opex	42,432	42,432	42,432
DUoS	65,600	64,938	80,542
Green levies	4,393	4,672	5,768
Total revenue target	**350,271**	**349,719**	**365,286**

Table 10 - Orkney Storage Park Revenue Target Summary

[14] In principle the asset could also be subject to a Capacity Market levy. However, this is likely to be imposed on the basis of electricity consumed during winter weekday evenings, when the battery is unlikely to be charging.

[15] Note that none of these charges are symmetric, meaning that they are not recovered when the asset exports energy

The cost associated with the inefficiency of the battery falls year by year. This reflects the decline in wholesale power prices seen over this period. By contrast, the increase in costs associated with green levies reflects the increasing expenditure under the Levy Control Framework as more RO- and ssFIT-eligible generation projects are commissioned, and the increase in DUoS charges is a result of increasing network costs in the SHEPD region.

5.11 Dispatching regimes

For the purpose of building a business case for the Orkney Energy Storage Park, a contracting and dispatching regime needs to be assumed. As indicated in **Error! Reference source not found.**, a number f possible revenue streams exist, but not all of these can be secured at any one time. In order to determine the optimal dispatch regime, the mutual exclusivities associated with different revenue streams need to be considered:

- If the asset has committed to providing STOR[16], it will receive availability and utilisation fees from National Grid, and can expect higher levels of utilisation
- However, in any period where the asset is committed to providing STOR it is precluded from providing constraint management services or participating in Triad avoidance[17].
- If instead the asset provides Flexible STOR, it is assumed that it can choose not to opt in to providing the service at the week-ahead stage, thereby making itself available for both constraint management and Triad avoidance.

Taking into account these mutual exclusivities, the two Orkney Storage Park dispatching regimes with the largest potential revenues were as follows:

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[16] Ordinarily, a device with less than a 3MW output would not meet minimum size requirements for providing STOR. It is assumed, however, either that the asset could have been included as part of an aggregator's portfolio, or that a derogation regarding this *de minimis* threshold is in place. In addition, the relatively small storage capacity of the battery also places constraints on the operation of the battery since STOR providers must be capable of delivering power for at least 2 hours (under current rules). It is assumed that the battery's discharge rate has to be reduced such that it exports power evenly over the required two-hour period. Given that the actual battery characteristics measured by SGS are 1.8MW and 0.625MWh, the battery must therefore be discharged at no more than 0.31MW (i.e. 17% of its maximum output).

[17] A similar adjustment must be made if the battery is to participate in Triad avoidance. In this case, there is no rule dictating the number of hours the asset must run. However, Triad periods are not known ex ante, and only last for half an hour. In order to receive payment the battery must be discharging during the Triad period. In a world of perfect foresight, the battery could discharge at half its capacity over the correct half-hour period. However, the forecast may actually only be able to indicate the day on which a Triad will fall. In this case, the battery would have to discharge for 3 hours (between 4pm and 7pm) to be sure of hitting the Triad period. For the purposes of this business case, it is assumed that a forecast will specify a 2-hour period on the Triad day, meaning the battery must discharge at no more than 0.31MW (17% of its maximum output, which is the same as was used for providing STOR).

- **STOR Priority**: the asset is contracted for both the constraint management contract and flexible STOR during summer periods, where the constraint management contract is most valuable. The asset is then contracted for committed STOR for the remaining winter months of the year when it would be expected to be utilised most frequently;
- **Flexible STOR & Triad avoidance**: the asset is contracted for both the constraint management contract and flexible STOR for the full year. By not committing to STOR ahead of time, the asset can offer constraint management services and engage in Triad avoidance during the winter months, making contract and dispatch decisions a week-ahead of time depending on the respective value of each service.

The relative value of these two operating regimes is sensitive to the value of STOR services and the level of TNUoS charges that could be avoided. These sensitivities are explored in Section 5.15, but between 2013 and 2015, revenue would have been maximised by opting for the STOR Priority strategy. This operating regime is summarised in the figure below.

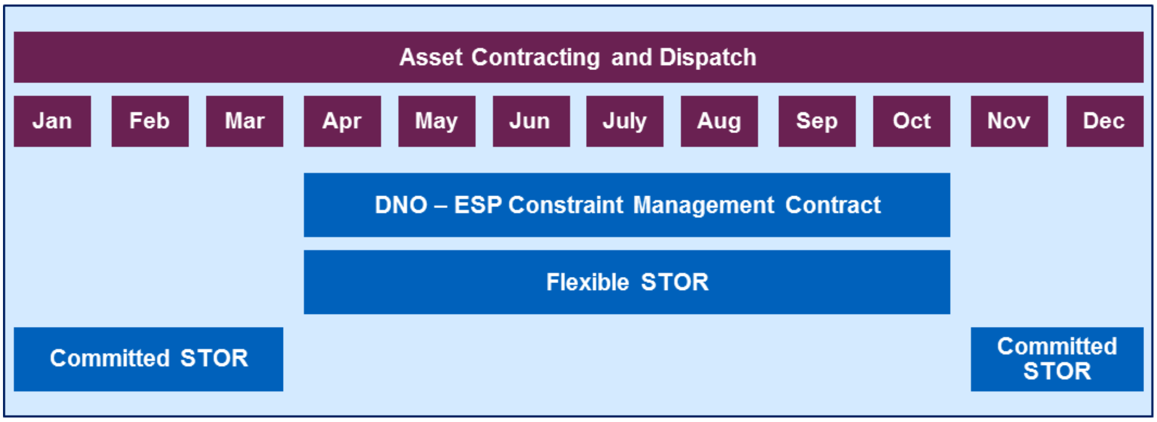

Figure 6 - STOR Priority

5.12 Revenue Streams

5.12.1 Ancillary services provision

Under the STOR Priority regime, the asset would be able to secure revenues from Flexible STOR between April and October, and Committed STOR in the remaining months, receiving payments for both availability and utilisation. In this hypothetical case the following revenues could have been produced:

- Flexible STOR: Availability payments generate **£3,400/annum** in 2013, falling to **£600/annum** by 2015 since availability payments have been in decline[18]. Utilisation payments corresponding to **£1,100/annum**; these revenues are more stable across years.
- Committed STOR: Availability payments generate **£12,600/annum** in 2013, falling to **£3,600/annum** by 2015. Utilisation payments contribute **£5,300/annum**.

[18] The assumption is made that the battery must discharge at a fraction of its maximum output to ensure it is exporting for the required 2 hours.

5.12.2 Constraint management

In addition to the revenues generated from STOR provision, it is assumed that the asset receives revenues from the DNO under its constraint management contract. The primary purpose of the ESS asset is to reduce the curtailment of distributed generation assets on Orkney. The constraint management contract's maximum value is assumed to be equal to the reduction in curtailment costs that those generators could see with the ESS in place[19].

Curtailment frequencies and durations were calculated by SGS, who modelled a number of different wind, generation, ESS systems and circuit ratings scenarios. Of the various scenarios analysed, the maximum curtailment avoidance was seen in a high wind case with all present day generation connected[20], with 109MWh of curtailment avoided as a results of the Orkney Storage Park.

To calculate the value of this avoided curtailment, the £/MWh revenue that a wind generator would receive through a combination of wholesale electricity price and ROCs was multiplied by the avoided curtailment volume to give the total avoided curtailment value on a monthly basis. The October 2013 Redpoint Reference Case wholesale power price projections and ROC values were used to calculate the present day and future £/MWh curtailment avoidance values. On this basis, curtailment avoidance, and hence the constraint management contract, was calculated to have a maximum benefit of **£5,500** in 2013, increasing to **£6,549** in 2015.

5.13 Revenue stream summary

Table 11 below gives the breakdown of potential revenues for the Orkney Storage Park, assuming that the asset is operated over the three year project lifetime under a STOR Priority dispatch regime. The overall revenue declines year on year as the increase in value that can be secured under the constraint management contract is more than offset by the observed fall in STOR payments.

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[19] We have made the assumption that the DNO acts to relieve constraints where this is economically viable, based on the avoided revenue loss to the generator. However, we note that under the current regulatory regime the DNO is not exposed to these costs, yet the cost of avoiding curtailment via installation of storage accrues to the DNO. We note that there is currently no regulatory or market mechanism to align the portion of costs on each party with the proportion of benefits on each party. At present, where generators have entered into non-firm agreements with DNOs there exists a misplaced incentive (in export constraint cases) where the benefits of installing a storage asset to avoid curtailment do not accrue to the agent that carries the cost (i.e. benefits are seen by the third party and generators, but costs by the DNO). However, the DNO does have the incentive of being able to connect more generation. In the future this assumption could change to reflect the avoided cost of wider reinforcement, reinforcement required in addition to any sole use assets required for a generation connection, where the DNO directly benefits..

[20] Previous analysis assumed that Dynamic Line Rating (DLR) would be used to increase capacity on the line between Zone 1 and the Core Zone in high wind conditions. However, since that time the DLR proposal has been dropped from consideration. Therefore this study focuses on the case where DLR is not used.

Annual revenue (£)	2013	2014	2015
Committed STOR	17,510	13,459	8,606
Flexible STOR	4,449	2,720	1,624
Constraint management	5,455	5,897	6,549
Total revenue	**27,414**	**22,075**	**16,778**

Table 11 - Orkney Storage Park Revenue Stream Summary

5.14 Business case

The business case for the Orkney Storage Park project is summarised in the figure below, using 2013 as the example. As was shown in Section 5.10, the 2013 revenue target is £350,000, most of which can be attributed to the need to recover £530,400 of capex over the asset's assumed three-year lifetime.

The revenue from offering Committed and Flexible STOR in 2013 comes to **£22,000**, leaving **£328,300** needing to be recovered through the constraint management contract with the DNO. The specific details of the contract between the DNO and the ESP cannot be given here, but based on the SGS analysis of the value of the ESP to generators that comes from avoiding curtailment, and assuming that the DNO was incentivised to pay the ESP on its behalf, the maximum annual value of that contract would be just **£5,500** in 2013.

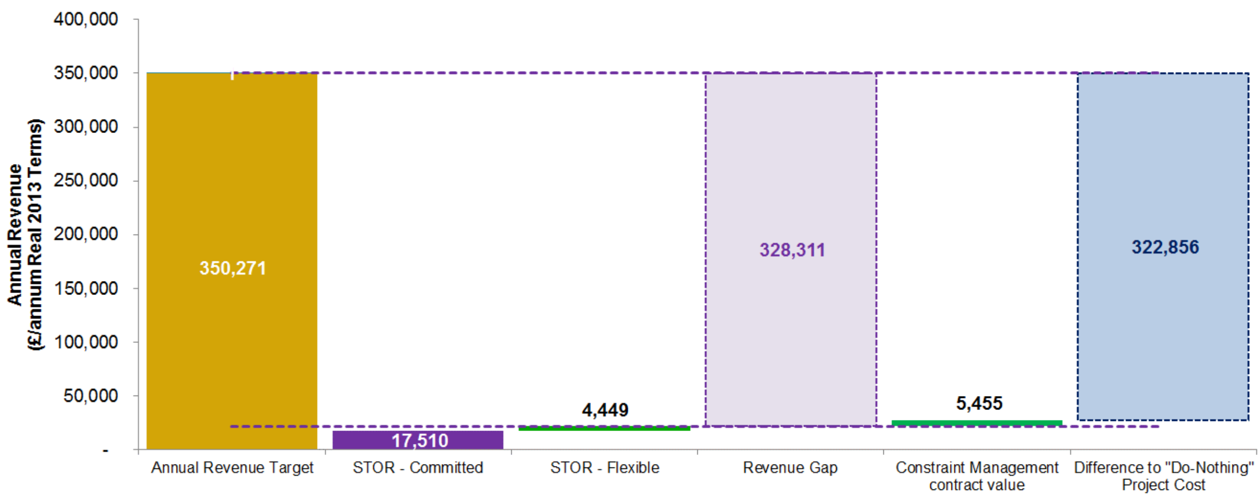

Figure 7 - Business Case for Orkney Energy Storage Park, 2013 Snapshot

12 shows the business case for the Orkney Storage Park project if it were to be assessed on pure commercial terms, rather than as an innovation project. Because the cost of the battery (including annuitised capex and opex) exceeds the potential revenue, the project would not be viable as a commercial enterprise. The net benefit against the "Do-Nothing" case is significantly negative.

Project Costs/Revenue (£/year 2013 values)	
Annuitised Cost of Battery & other costs	-350,271
Committed STOR	17,510
Flexible STOR	4,449
Constraint management value (Core Zone)	5,455
Cost relative to "Do-Nothing" case	-322,856

Table 12 - Investment Decision Table

There are a number of factors that contribute to the negative economic assessment for the Orkney Storage Park project, which, if changed, could affect the value of the project:

- The upfront capex for the battery is high. Whilst there is uncertainty about the future trajectory of battery costs, it is generally agreed that costs are falling rapidly, and perhaps more rapidly that has been forecast in the past[21]. A later commissioning date should be expected to have lower installation costs.
- Given that the project only lasted for three years, it is assumed that this capex needs to be recovered over this short period of time. The economic lifetime of commercial storage projects is likely to be longer.
- The value of STOR has been in decline in recent years, which is likely to reduce the revenue that could be achieved under the STOR Priority regime in future. Instead, the dispatching regime could be changed to target Triad avoidance.
- TNUoS charges are relatively low in Northern Scotland at present, meaning that Triad avoidance could be more valuable in a different location. Were the ESS asset to be sited elsewhere, however, the network may be less constrained, so there is no guarantee that a constraint management contract could be secured. This can be seen in the table below where the charges increase the closer to the south of the country the demand is located. In other words if the site were to reduce the network peak by a kW in Zone 13, they earn 1.9 more revenue than if they offered the same reduction in Zone 1.

[21] http://ecosummit.net/uploads/eco13_151013_1700_michaelwilshire_bnef.pdf

Zone Number	Zone Name	Final 2015/16 (£/kW)
1	Northern Scotland	23.47
2	Southern Scotland	26.79
3	Northern	32.62
4	North West	35.68
5	Yorkshire	36.29
6	N Wales & Mersey	35.62
7	East Midlands	39.07
8	Midlands	39.63
9	Eastern	41.18
10	South Wales	37.61
11	South East	43.74
12	London	46.24
13	Southern	44.79
14	South Western	43.98

Table 13 – Half Hourly Demand Tariffs[22]

- Fixed and capacity-based DUoS charges in DNO areas are specific to each licensed area. As such these could be reduced if the battery were sited elsewhere.
- The green levies imposed on the asset are calculated based on its gross consumption. Whilst it could be argued that net consumption is a more appropriate measure, because the battery has high levels of self-discharge, this would not have a significant impact. However, it may be that a specific levy exemption could be made for storage and flexible demand assets.

Each of these variants is tested in the next section in order to assess the potential business case for a battery installed today or in the future.

5.15 Business case for future projects: sensitivity analysis

This section uses the physical characteristics of the Orkney Storage Park project, but updates some of the key parameters to understand the potential evolution of the business case for distribution-connected ESS assets.

[22] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=39384

5.15.1 Updated view of Orkney Storage Park: Commission in 2015 & revise dispatch regime

In order to provide a new baseline for this section, the business case for the Orkney Storage Park project is revised to reflect its estimated costs and revenues were it to be built in 2015[23]. This change in date has a number of effects on both the costs and revenues associated with the project, including:

- A fall in capex from £530,000 to £302,000 in light of rapid learning curves assumed for batteries. Since a portion of opex is assumed to be scaled to the capex, this is also reduced.
- The value of STOR services has fallen since 2013, reducing the revenue available
- Demand TNUoS charges have increased since 2013, making Triad avoidance more valuable
- Constraint costs have increased as an increased level of wind and micro-generation is connected to the grid

If the dispatching regime were to remain as STOR Priority, the shortfall against the "Do-Nothing" case would have fallen from £322,900 to £230,500, as show in Figure 8. This is primarily driven by the assumed fall in battery costs.

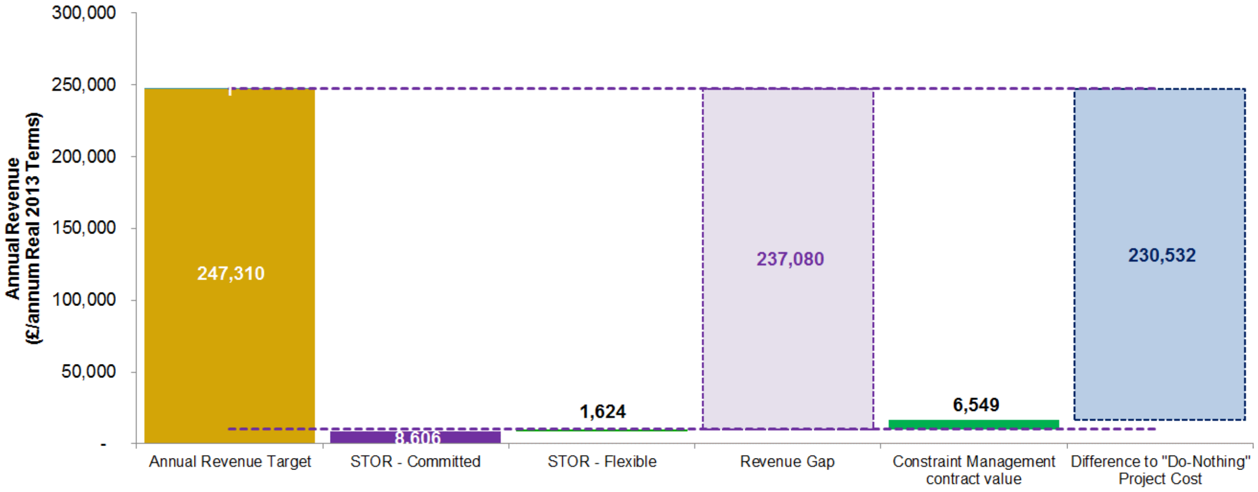

Figure 8 - 2015 Orkney Energy Storage Park Business Case under STOR Priority Regime, First Year Snapshot

In light of the fall in STOR value, and an increase in TNUoS charges, it is more profitable to forego revenues from Committed STOR in the winter months in order to be able to participate in Triad avoidance. This revised regime is summarised in Figure 9 below.

[23] Note that all prices remain in real 2013 terms for consistency with the previous section

Figure 9 - Flexible STOR & Triad Avoidance

Under the Flexible STOR & Triad avoidance regime, the asset would be able to secure the following revenues:

- Flexible STOR revenues come from both availability and utilisation payments. Availability payments are assessed on the basis of a maximum 3,860 hours of availability throughout the year, but making the assumption that the battery must discharge at a fraction of its maximum output to ensure it is exporting for the required 2 hours. This generates **£1,100/annum**, reflecting a fall in STOR availability payments since 2013. The assumed utilisation is 19MWh/annum, corresponding to **£2,800/annum**.
- Triad avoidance revenues are calculated on the assumption that the asset needs to discharge over 2 hours (of each potential 3-hour Triad window) in order to be confident of coinciding with the Triad half-hour. The TNUoS Zonal Demand Tariff for the Northern Scotland region increases year by year (£23/kW in 2015, £30/kW in 2016) but with a step change in 2017 down to £19/kW, reflecting the impact of planned network reinforcement. This translates into annual revenues for the Orkney Storage Park of **£7,200**, **£9,100** and **£5,700** in 2015, 2016 and 2017, respectively.

Under this revised regime, the shortfall is reduced further to £229,600 since the revenue from Triad avoidance and the fact that it can be achieved whilst offering Flexible STOR offsets the losses associated with opting out of providing Committed STOR. Whilst the difference is marginal in 2015, the benefit is more marked for future years as TNUoS charges are projected to increase.

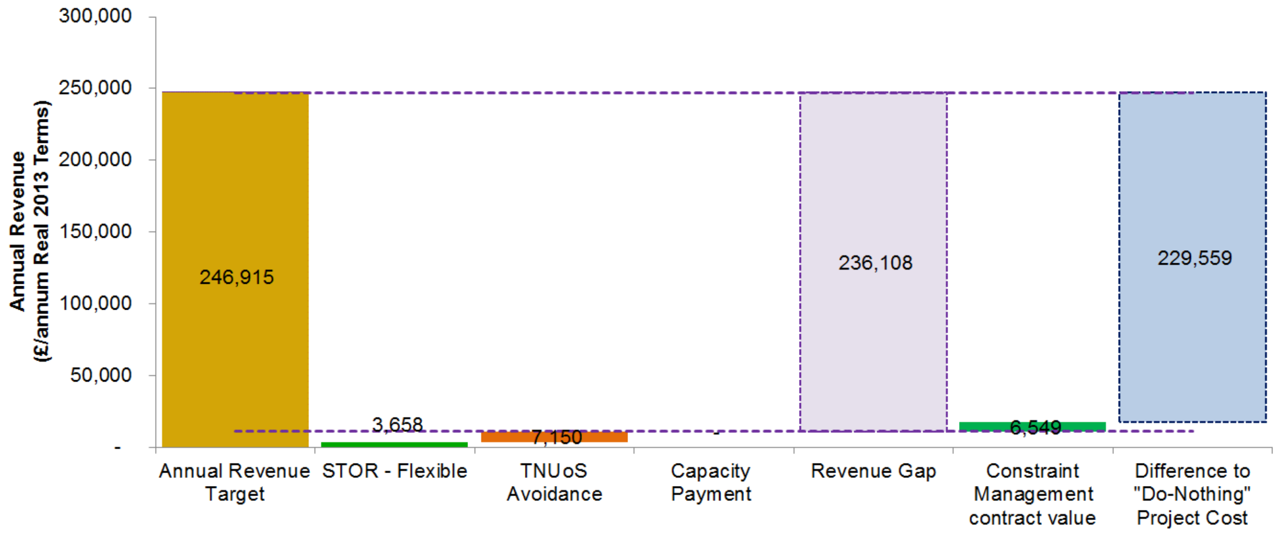

Figure 10 - 2015 Orkney Storage Park Business Case under Flexible STOR & Triad Avoidance Regime, First Year Snapshot

Using this configuration as a baseline, the following section explores the sensitivities identified above.

5.16 Sensitivities

5.16.1 Increase battery lifespan to 10 years & delay commissioning date to 2020

Extending the battery lifespan to 10 years has two effects:

- By recovering the upfront battery capex over a longer period of time, the annuitised battery cost is reduced from £130,200/annum to £46,400/annum, reducing the annual revenue target from **£246,900** to **£163,100**.
- Although it does not affect the other costs and revenues in 2015, the project is operational for longer, giving rise to addition revenue from two sources:
    - From 2018 it is assumed to receive revenues from the Capacity Market. Revenues are calculated based on the results of the first GB Capacity Auction, held in 2014, which saw a clearing price of £19.95/kW (in 2013 real terms).
    - Because TNUoS charges are expected to increase, revenues from Triad avoidance are increased in later years.

If in addition, we assume that the asset is commissioned in 2020, the battery cost is expected to have fallen considerably, from £302,100 in 2015 to just £147,700.

The combined effect of a later commissioning date and longer lifespan can be seen in Figure 11, where the shortfall has reduced to £70,600.

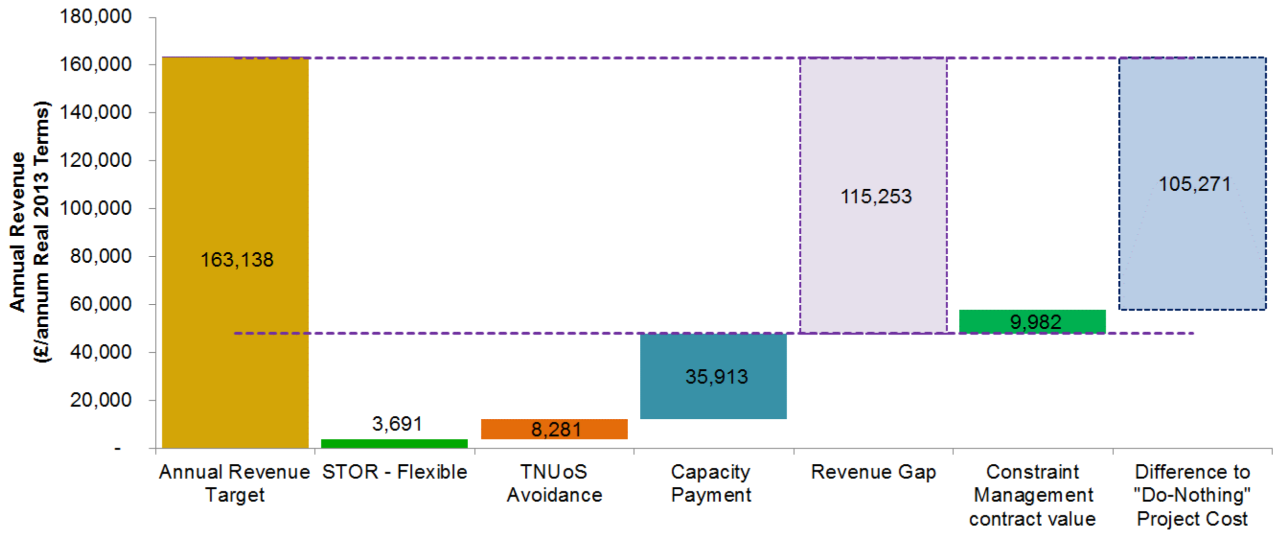

Figure 11 - 10yr lifespan Orkney Storage Park Business Case, Commissioning 2020, First Year Snapshot

5.16.2 Move asset to the SEPD region

The location of the storage park affects its business case for a number of reasons. If we imagine that it instead sited in Southern Electric Power Distribution (SEPD) region, three key parameters will change;

1. Any revenues from constraint management are assumed to be no longer available
2. TNUoS charges in the Southern region are higher than in Northern Scotland, increasing the potential value of Triad avoidance
3. Fixed and Capacity-related DUoS charges, are lower in the SEPD region than the SHEPD region, reducing the asset's underlying cost and hence the annual revenue target

In this case, the loss in potential revenue from constraint management is offset by the increased value of Triad avoidance. Furthermore, the result of reducing the annual DUoS charge from **£80,700** to **£35,000** by moving to a lower cost region is an annual revenue target of **£82,900**, and a shortfall against the "Do-Nothing" case of **£24,600**, as shown in Figure 12.

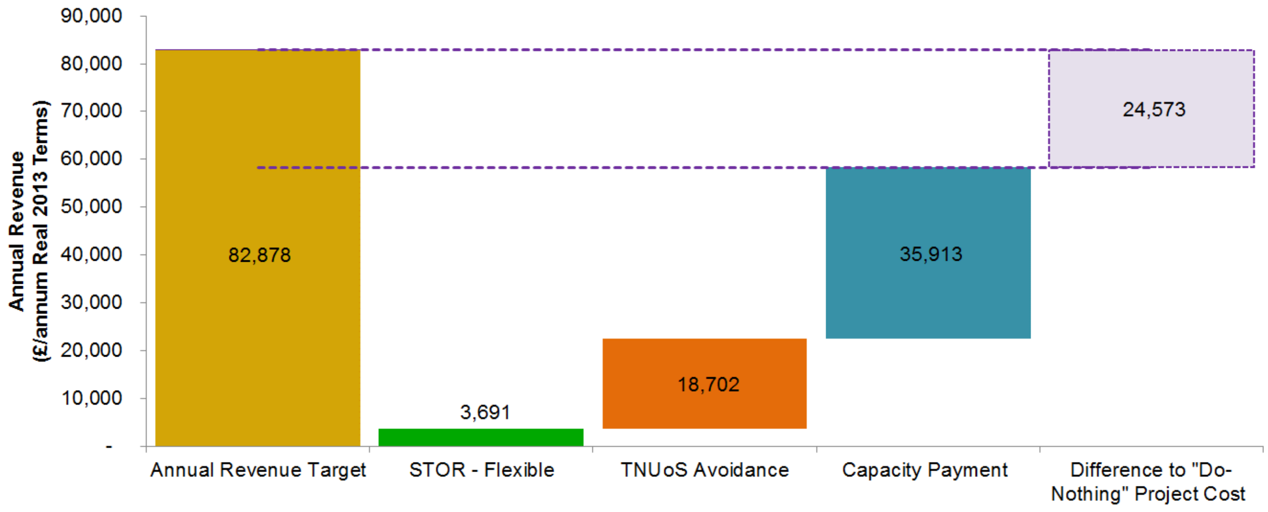

Figure 12 - 2020 10yr Lifespan Sited in Southern Region, First Year Snapshot

In addition to the additional revenue that could be earned from a southern UK located ESS, there is also value in the flexibility offered as part of the ESS being containerised and not fixed to one site for its life cycle. This flexibility means that if the constraint being managed moves away, i.e. through demand or generation profile amendments, then the system can be relocated. Typically this kind of value is referred to as a Real Options Value. To put a value to this was seen as out of scope for this project but there are currently ongoing discussions with the Regulator to try and understand how this value can be defined and quantified. Further work is expected on this in the future.

5.16.3 DUoS & Green levy exemption

Considering the benefits that storage assets can deliver to the network when used to manage network constraints, it can be argued that current DUoS charging arrangements are not cost reflective. In addition, although these assets are net consumers of electricity, by allowing more distributed renewable generation onto the network they help to deliver the Carbon Plan, so a case can be made that Green charges should not be levied.

The treatment of storage assets for Green levies (including the Climate Change Levy and Supplier Obligations intended to pay for the RO, CfDs and ss-FIT), has not been made explicit by Ofgem[24]. The assumption made in the above analysis is that the asset would incur these levies on the basis of its gross consumption, adding **£4,000** to the 2020 annual revenue target and increasing year on year. Calculating on a net consumption basis would only reduce this figure slightly, since the consumption of power by the asset's auxiliary systems is an order of magnitude higher than the power exported by the battery. It is conceivable, however, that a specific exemption could be made in the case of storage assets, on the basis

[24] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/Project-Documents/SNS4.6_SDRC+9.3+-+CA+for+IU+of+Flexibility_v1.0.pdf

that they are comparable to idle generators (e.g. offline nuclear assets or those providing reserve), which are exempt from these charges. This would reduce the annual revenue target by **£4,000** in 2020, rising to a **£11,200** annual benefit in the final year of the project.

DUoS charges are intended to reflect the cost to the DNO of accessing its network. The above analysis has assumed that the asset has two MPANs – one for import and one for export – and therefore incurs a fixed charge as both a generator and as a load. The annual cost of this fixed charge in the SPEN region, however, is only **£800**, which would reduce to **£400** for a single MPAN. More significant is the capacity charge imposed on consumers, which adds **£34,800** to the storage asset's annual revenue target.

As is reflected in their negative unit rates, generators give a net benefit to the DNO when they export, on average, for demand-dominated networks. The capacity charge is intended to reflect the cost of network reinforcement at time of peak demand. Given that a storage asset is unlikely to be charging when the distribution network is at peak demand, it may be reasonable to waive the capacity charge or adjust it to be more cost reflective, reducing the annual revenue target by up to **£34,800**. If an ANM system could monitor the state of the asset as it does in Orkney, the DNO could guarantee that the storage asset was indeed not contributing to network peaks.

The overall impact of removing both Green Levies and DUoS charges is shown in **Error! Reference source not found.**3. In this case, the reduced annual revenue target can be achieved via a combination of Flexible STOR, Triad avoidance and revenues from the Capacity Market. This leads to an annual net benefit of **£14,800** against the "Do-Nothing" case, even without revenues from constraint management.

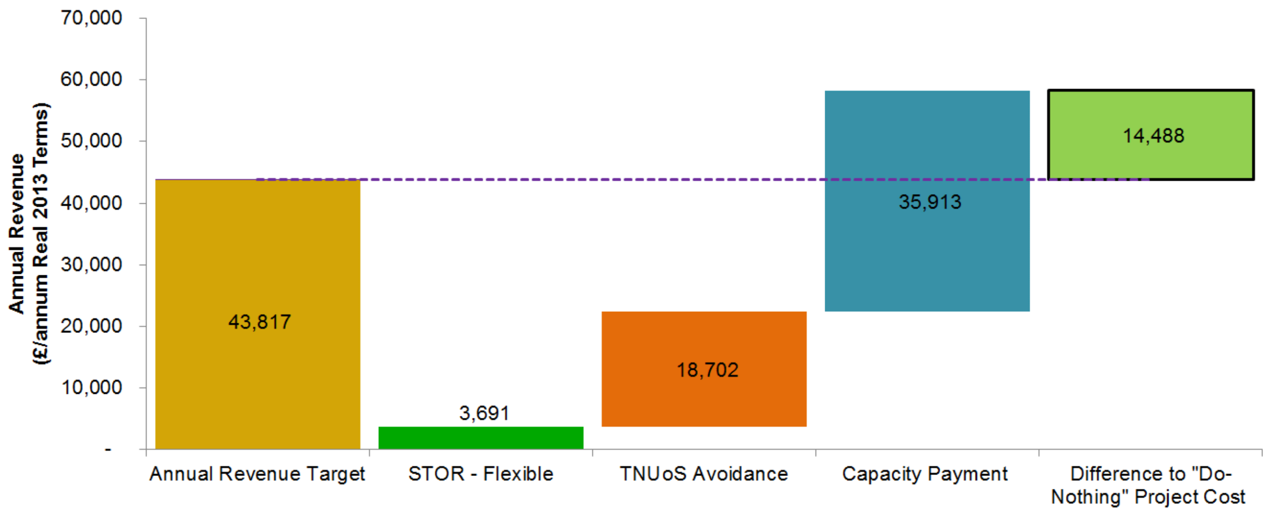

Figure 13 - 2020 10yr Lifespan Sited in Southern Region, Excluding DUoS & Green Levies, First Year Snapshot

5.16.4 Sensitivity summary

The cumulative effect of the various sensitivities described above are summarised in Table 14.

Sensitivity	Revenue Target (£)	Achieved Revenue (£)	Net Revenue (£)
2013 Base Case	350,271	27,414	-322,856
Commission in 2015	247,310	16,778	-230,532
Revise dispatch regime	246,915	17,356	-229,559
Increase battery lifespan to 10 years	163,138	17,356	-145,782
Delay commissioning date to 2020	128,506	57,867	-70,639
Move asset to the SEPD region	82,878	58,305	-24,573
DUoS & Green levy exemption	43,817	58,305	14,488

Table 14 - Sensitivity Analysis Summary

5.17 Business Case Conclusions

Table 14 presents the change in net revenue, per identified sensitivity, as a net revenue improvement, regardless of whether though this change comes from an increase in achieved revenue or a decrease in revenue target. Table 15 splits out whether the business case improvement has come from an increase in earned revenue, or a reduced revenue target. It then seeks to quantify which sensitivities had the largest impact and whether they are a technology or market based way of improving the sensitivities.

Sensitivity	Revenue Target (£)	Effect (£)	Achieved Revenue (£)	Effect (£)	Net revenue (£)
2013 Base Case	350,271	------------	27,414	------------	-322,856
Commission in 2015	247,310	**-102,961**	16,778	-10,636	-230,532
Revise dispatch regime	246,915	-395	17,356	578	-229,559
Increase battery lifespan to 10 years	163,138	**-83,777**	17,356	0	-145,782
Delay commissioning date to 2020	128,506	-34,632	57,867	40,511	-70,639
Move asset to the SEPD region	82,878	**-45,628**	58,305	438	-24,573
DUoS & Green levy exemption	43,817	-39,061	58,305	0	14,488

Table 15 - Sensitivities Impact on Business Case

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From this analysis it reveals that the three largest improvements in the business case are driven by the following three amendments:

- Firstly by moving the commissioning dates to 2015 from 2013. This is based on the forecasted reduction in manufacturing costs associated with an increase in production with its associated efficiencies;
- Secondly by increasing the life cycle of the ESS would result in a lower annual revenue target as the ESP would have longer to pay of the total ESS cost; and
- Thirdly by choosing a site closer to the demand centres in the south of the country in order to gain access to better Triad Avoidance fees.

What this means is that in order to make a storage project viable it is not simply a case of waiting for the capacity market to initialise, which is the fourth largest business case improvement, but rather it also requires manufacturing improvements or locational variations to ensure the right existing markets can be targeted. As such it can be argued that the market for storage exists already and what is required is fine tuning of the various sensitivities rather than a creation of a specific storage energy market.

6 Technology Readiness Level (TRL)

At the start of the project the concept being trialled, management of a constraint management contract, was judged to be at TRL 6. This was due to the ESS being a prototype that was to be tested in a working environment. Following the project it is judged that the TRL has risen to 8 because of the ability to deploy and manage a constraint management contract has been learned through the project.

7 Performance compared to original project aims, objectives and success criteria

Objective	Met?	Commentary
1 - Enter into a commercial contract with an ESP to provide constraint management services	✓	Contract was drafted and signed by the ESP and the DNO that covered the terms and conditions (see appendix II and the closedown report for SSET1007 Orkney Energy Storage Park) governing a constraint management contract Orkney.
2 - Modify existing generator and energy storage ANM interface to allow import requests to be sent to the ESS	✓	Existing interface between generators controlled through the ANM and the ANM was modified to allow the ESS to be dispatched as required for constraint management. Appendix I and Section 5.2 demonstrate the requirements and the HMI screen shots of the completed work.
3 - Facilitate the connection of an ESS to the distribution network in Kirkwall	✓	ESS connection facilitated through preparation and implementation of interface between ESS and the ANM. In addition facilitation was provided through engagement with the emergency services as can be seen in Section 5.2 and 5.3
4 - Service the contract over a 3 year period	✗	In total the contract was in place for 31 months and not 36 months. This was due to the delays in the previous project during the procurement phase having a knock on effect on this project. This is discussed further in Section 8.
5 - Summarise the different markets the ESP has managed to access during the project	✓	This report has summarised the markets which the ESP could have entered and has extended that to show what the picture looks like in the future towards 2020 as detailed in Section 5.5 to 5.18.

Table 16 - Extent to which objectives have been met

Objective	Met?	Commentary
For this project to be a success the final report will have a minimum of an understanding of one other market, aside from the constraint management market, that ESPs can access and generate income from.	✓	This report has explained in detail the markets currently, and in the future, that will allow access to distribution network connected ESSs. This has been quantified using the measured technical parameters obtained through ESS testing. All of this is laid out in Section 5.5 to 5.18.

Table 17 - Extent to which success criteria have been met

8 Required modifications to the planned approach during the course of the project

Originally the project had aimed to service the contract over 36 months, as this should have allowed the ESP enough time to set up some additional revenue streams. However the project that preceded this project, SSET1007 Orkney Energy Storage Park, was delayed in getting to the point of signature. This was caused by an extension granted during the procurement process to allow more in depth safety cases to be prepared and submitted by the tender applicants. This in turn had a further knock-on effect with the rest of the planned safety appraisal process which in turn led to a delay in getting the signatures required, which all resulted in an overall delay of five months for this project. Normally this could have been accounted for through the approval of an extension of the project timeline, but this was not possible as the LCNF Tier 1 funding ended on the 31st of March, meaning the project could not extend using the same funding. As such the plan was to run the project as planned and then extend into the follow on funding regime if it was allowable and if it was worthwhile doing so. However as the ESP was not inclined to further engage with the energy markets, due to the prohibitive cost of doing so for a relatively small asset, then this option was not progressed as it would have cost the UK customer more without delivering any additional value.

9 Significant variance in expected costs and benefits

The table shows a breakdown of the money spent through the project.

Item	Forecast	Actual	Variance (£k)	Variance (%)
Project Management	£62,333	£72777	£10,444	17
Site Works	£104,750	£59552	-£45,197	-43
Contract Billing	£982,043	£269,786	-£712,256	-73
Safety Case	£43,050	£46,774	£3,723	9
ICT Design	£125,638	£89165	-£36,472	-29
Analysis	£50,000	£105739	£55,739	111
Contingency 10%	£136,781			
Total	£1,504,595	£643,794	-£860,800	-57

Table 18 - Project costs

The following is an explanation of variance between the forecast and the final spend figures.

- The project management actual spend figures were 17% more than had been forecasted and this was due to the extra time required to resolve the site issues that affected the ESS. They required more meeting time and more site visits in order to end up at a satisfactory solution.
- The site works cost was 43% lower than forecast due to the original incorporation of decommissioning costs, which were not required as the ESP included these costs in their own budgets.
- The contract billing was the largest reason for the reduction in overall expenditure, as it was a difference of 73%. This was for a range of reasons as laid out in Section 5.4.3 where it shows that the ESP did not participate in over half of the availability periods as well as the remaining billing rule compliance failures.
- The ICT design was down 29% on the original forecast as creation of the ESS to ANM interface did not have to be carried out from first principles and as such did not require as much work. This was because of the Shetland ESS interface and the Orkney ANM generator interface already having been developed and functioning.

- The analysis was 111% over and this was due to the lack of engagement of the ESP with the energy markets, which required more desktop analysis in order to ensure that the project was a success.
- All in all, these figures led to the project budget being underspent by 57%.

10 Lessons learnt for future projects

There were a number of lessons learned through the course of this project that have not been discussed already and are as follows:

10.1 Safety Case

Key learning points were identified during the safety appraisal of the ESS:

- When engaging with the emergency services it is very important to understand the legal background to the engagement, i.e. it is not mandatory to engage with the emergency service but it is good practise. During the first meeting it quickly became apparent that the parties engaged with the process did not have any centralised guidance they could follow and it was down to each individual’s interpretation, which could have been a difficult situation if it was not managed correctly.
- When engaging with the emergency services it is best to do so during the design phase of the project. In that way it is a lot easier to account for any requirements identified by the emergency services.
- When presenting material to emergency services, and indeed any stakeholder, assume a non technical background and try to start from basic facts in plain language. Also, where possible, relate topics to everyday items/practices which are more readily understood such as electric cars, mobile phones and laptop batteries. In this way understanding can be developed without the technical detail being a barrier to understanding of the relevant issues for non-technical stakeholders.

10.2 Supplier Engagement

Whilst delivering the project the following was learnt about supplier engagement and commercial contracts:

- Ensure that those providing crucial parts of the project, where possible, are linked to the project leaders. In this project the supplier MHI did not have a direct contractual relationship with SSEPD which meant that the exchange of information and resolution of issues could have been handled more efficiently.

10.3 Commissioning

Whilst delivering the project the following was learnt about commissioning ESSs:

- Whilst commissioning an ESS the export and the import need to be tested, which leads to a situation where the ESS will require to import and export energy from somewhere. At that time the system will not have been commissioned so connection to the network is not allowed. There are options available here depending on the discretion of the DNO technical authority, in this case the commissioning team and the system planners. Firstly, a load bank could be used to supply an energy demand without it coming from the network. Secondly, a temporary diesel generation set could be used to supply the energy. Finally, if the appropriate level of electrical protection has been commissioned already then, at the discretion of the technical authority, the ESS may have a limited connection to the network.

11 Planned implementation

The main uses to date of the principles and the knowledge gained during this project has been to inform the creation of the Constraint Managed Zones (CMZ) in the SEPD area. In addition UKPN were aided in their development of the Smarter Network Storage Tier 2 Project[25]. Topics discussed revolved round commercial models and safety impact analysis. Below is a description of the principles and the knowledge transferred through the CMZ work.

11.1 Constrained Managed Zones

11.1.1 What is a Constraint Management Zone (CMZ)?

This is considered to be a geographic region served by an existing network where network requirements related to management of peak electrical demand are met through the use of demand reducing or demand shifting techniques, such as Demand Side Response and Energy Storage. These CMZ techniques will be offered as a managed service to SEPD by a CMZ supplier.

11.1.2 CMZ Round 1

We are looking for CMZ suppliers to manage post-outage peak demand constraints. CMZ techniques must be reliable and will be subject to additional test operations throughout the year to ensure satisfactory performance. When not required for CMZ operation, and within the limitation of any connection agreement, our suppliers would be free to operate or trade these techniques as appropriate.

11.1.3 Context

SSEPD has established and evaluated a number of solutions to the challenges facing networks in the UK and beyond, and have formed the view that a number of these solutions are at a state of maturity both technically and commercially that it is time to turn to the market for real. One of the biggest opportunities for the application of 'smarter' solutions on the network today is in the management of thermal and voltage constraints.

[25] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/

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There are clear signs in the South of England that the balancing and other markets are stimulating interest in energy storage deployments, in addition the work undertaken in the New Thames Valley Vision Tier 2 project, as well as learning from other DNOs' projects, has shown an appetite for Demand Side Response in non-domestic buildings and a technological readiness for this solution. In our Orkney Energy Storage Park project we tested the concept of contracts services bidding in to provide peak constraint management services, in the case of Orkney this specifically targeted bi-directional storage technologies. We do not anticipate domestic customer techniques to be suitable for CMZs at this stage due to the level of maturity and the ongoing development of smart metering and associated markets.

It is important to note that we do not consider this opportunity as a "demonstration" or innovation project, and therefore the service provision will be fully commercial in nature.

Outside defined Service Windows we do not intend to restrict CMZ suppliers from participating in any other market that is compatible with the contracted service and the capabilities of the network connection point (i.e. operates within any physical network constraint and connection agreement). We anticipate that a key element of any successful response will be the effectiveness with which the supplier generates other income from the assets to minimize the cost of the contracted service.

11.1.4 Nature of Service

Round 1 considers electrical networks which are approaching a point where the pre-existing network capacity cannot meet power requirements should an outage (planned or unplanned) coincide with periods of highest demand. For all other periods, the demand requirements are lower and existing capacity can provide sufficient post outage support.

Traditional reinforcement techniques would increase overall capacity across all time periods by including an additional circuit or by up-rating an existing one. CMZ techniques do not seek to increase capacity but will reduce or time-shift demand to avoid capacity constraints. Since capacity constraints only occur at periods of maximum demand, and only if an outage coincides, CMZ techniques need only be available during pre-defined Service Windows and may only be called upon should an outage coincide. Should a CMZ technique require a new electrical Point of Connection to the SEPD network, the CMZ supplier should make a separate application.

11.1.5 Orkney Energy Storage Park Knowledge Transfer

The principle points feeding into the CMZ work were:

- That the market was maturing towards being able to provide constraint managed services as an economically justifiable revenue stream, as demonstrated by the successful tender process that was run through the Tier 1 project to inform some of the CMZ work, which reduced time to deployment as well as knowing that the principles contained within it worked;
- A good understanding of the additional revenue streams that assets used to provide constraint managed services, could attract. This allowed better building of the service structure for the CMZ

to allow easier market access for those willing to participate in the CMZ. In turn this means that the tendered prices should be lower, which was a key aim of the Tier 1 project;

- The health and safety implications of the use and deployment of ESSs, especially Lithium-Ion, has been used in the CMZ work to ensure that our highest priority is suitably addressed by those looking to participate.

12 Project replication and intellectual property

The following tables list all physical components and knowledge required to replicate the outcomes of this project, showing how the required IP can be accessed by other GB DNOs. Further detail relating to any knowledge item is available from SSEPD on request through futurenetworks@sse.com.

Component	**Products used in project or commercially available equivalents**
Active Network Management System	Smarter Grid Solutions Thermal Constraint Management ANM 100 System. Info available at info@smartergridsolutions.com
Energy Storage System	Mitsubishi Heavy Industries 2 MW 500 kWh Lithium-Ion Containerised Battery Electrical Energy System
Constraint Management Contract	Ancillary Services Agreement as can be seen in the SSET1007 Orkney Energy Storage Park Closedown Report

Table 19 - Components required for project replication

Knowledge item	**Application**	**IP ownership and availability**
Baringa Report *SSE Orkney Storage Park Business Case Definition V3*	Baringa Report into the ESS business case at the start of the project	SSEPD, email requests for info to future.networks@sse.com.
Baringa Report *Orkney Storage Park Phase 2 Business Case Update_V04*	Baringa Report into the ESS business case refreshed for measured technical parameters	SSEPD, email requests for info to future.networks@sse.com.
Baringa Report *SSE Orkney Storage Park Business Case Final Update*	Baringa Report into the ESS business case as it stands at the end of the project as well as looking to the future.	SSEPD, email requests for info to future.networks@sse.com.

Table 20 - Knowledge products required for project replication

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Appendix I
ANM and ESS Interface Requirement List

Requirement	Detail
1	Each ESS will have a dedicated interface with the Orkney ANM scheme
2	An LAC will be supplied for each ESS included within the Orkney ANM scheme and a direct communication link will be installed between the LAC and the control system of the ESS.
3	The LAC-ESS communication link will use one of the following open standard communication protocols: • *DNP 3.0 Over IP (Slave only)* • *DNP 3.0 RS-232/485* • *Modbus TCP/IP* • *Modbus RS-232/485*
4	When exporting power the ESS will be subjected to the conventional rules of the Orkney ANM scheme as applied to all new power exporting devices connecting to the network as part of the ANM scheme.
5	The ESS will be assigned a position within the Orkney ANM priority stack.
6	The ANM scheme will issue a real power set-point instruction to the ESS to indicate the limit above which its power export must not exceed.
7	The ANM scheme will, when required, issue “trip” instructions to the interface circuit breaker of the ESS to disconnect it from the network in accordance with the escalating control actions taken by the ANM scheme to ensure network security is maintained.
8	Upon the breach of a thermal constraint the ANM scheme will attempt to allocate as much of the required curtailment as possible to the ESS in the form of a reduction in power export or an increase in power import.
9	The ANM scheme will issue a real power set-point instruction to the ESS to indicate its required point of operation if it is to participate in the reallocation of curtailment away from generators. This will be in addition to the real power set-point instruction associated with Req. 6.
10	The ANM scheme will allow an ANM operator to manually override the existing value of the real power set-point described in Req. 9. The operator will be able to manually input a new value for this real power set-point via the ANM scheme. *This will be required for testing of the ESS and the ANM interface.*
11	The ANM scheme will be capable of receiving an availability signal from the ESS. This signal will have two states: “Available” and “Unavailable”. Only when this signal is in the “Available” state will the ANM scheme attempt to reallocate curtailment from generators to the ESS.
12	The real power set-point signal indicating the limit above which ESS power export must not exceed will be ‘released’ in the conventional manner of the ANM scheme akin to the real power-set point issued to generators

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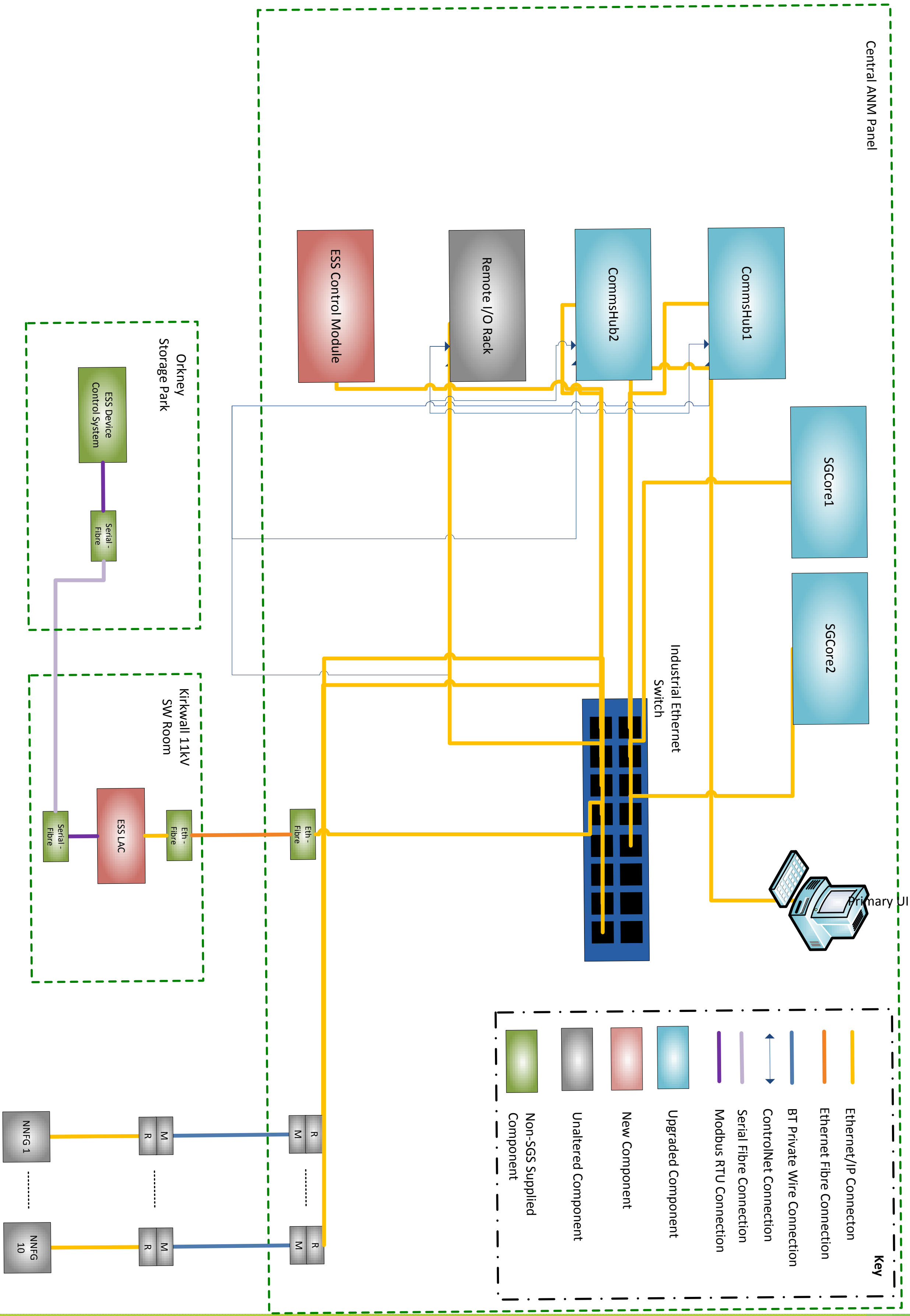
	within the ANM scheme.
13	The real power set-point indicating the ANM's requested operating position for the ESS will be 'released' back to a pre-determined default position that can be updated by the ESS.
14	The ANM scheme will be capable of receiving a real power value from the ESS that indicates the default operating position of the ESS upon the 'release' from ANM control.
15	The ANM scheme will receive values from the ESS indicating if any limits are presently imposed on its power import or export capability. The ANM scheme will then account for these limits and will not issue real power set-point instructions outside of these limits.
16	The ANM scheme will monitor the response of the ESS to critical ANM scheme instructions. Failure by the ESS to respond to a critical ANM instruction will result in the ESS being disconnected from the network. This will be initiated by the issuing of "trip" instruction to the interface circuit breaker of the ESS.
17	The ANM scheme will monitor the integrity of the communication link between it and the ESS as well as the quality of the input data received from the ESS. If either of these is degraded the ANM scheme will issue a real power set-point instruction to the ESS that is predetermined and operator configurable.
18	The ANM scheme will monitor the state of the Orkney to UK Mainland Interconnectors and prohibit the use of the ESS as an importer of power if either of these interconnectors is out of service.
19	The ANM scheme will continuously monitor and record the state of charge of the ESS throughout each availability period.
20	The ANM scheme will record the total energy imported by the ESS upon instruction from the ANM both inside and outside of the availability periods. This will include determining energy import undertaken by the ESS but not requested by the ANM scheme.
21	The ANM scheme will store configurable limits on the operation of the ESS such as a MWh limit on ESS import instructions issued by the ANM scheme. These will be configurable over different time periods such as per hour/month.



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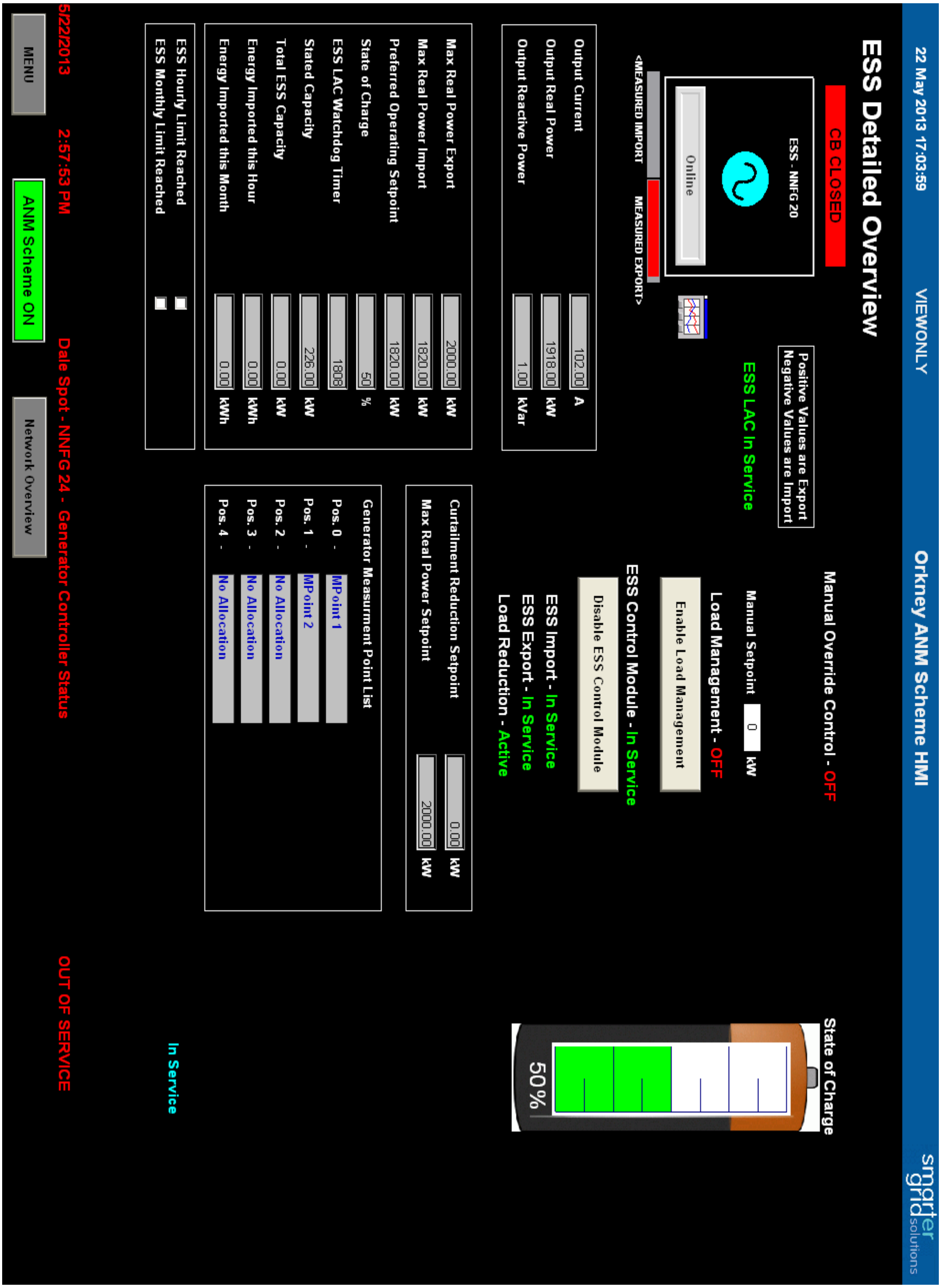

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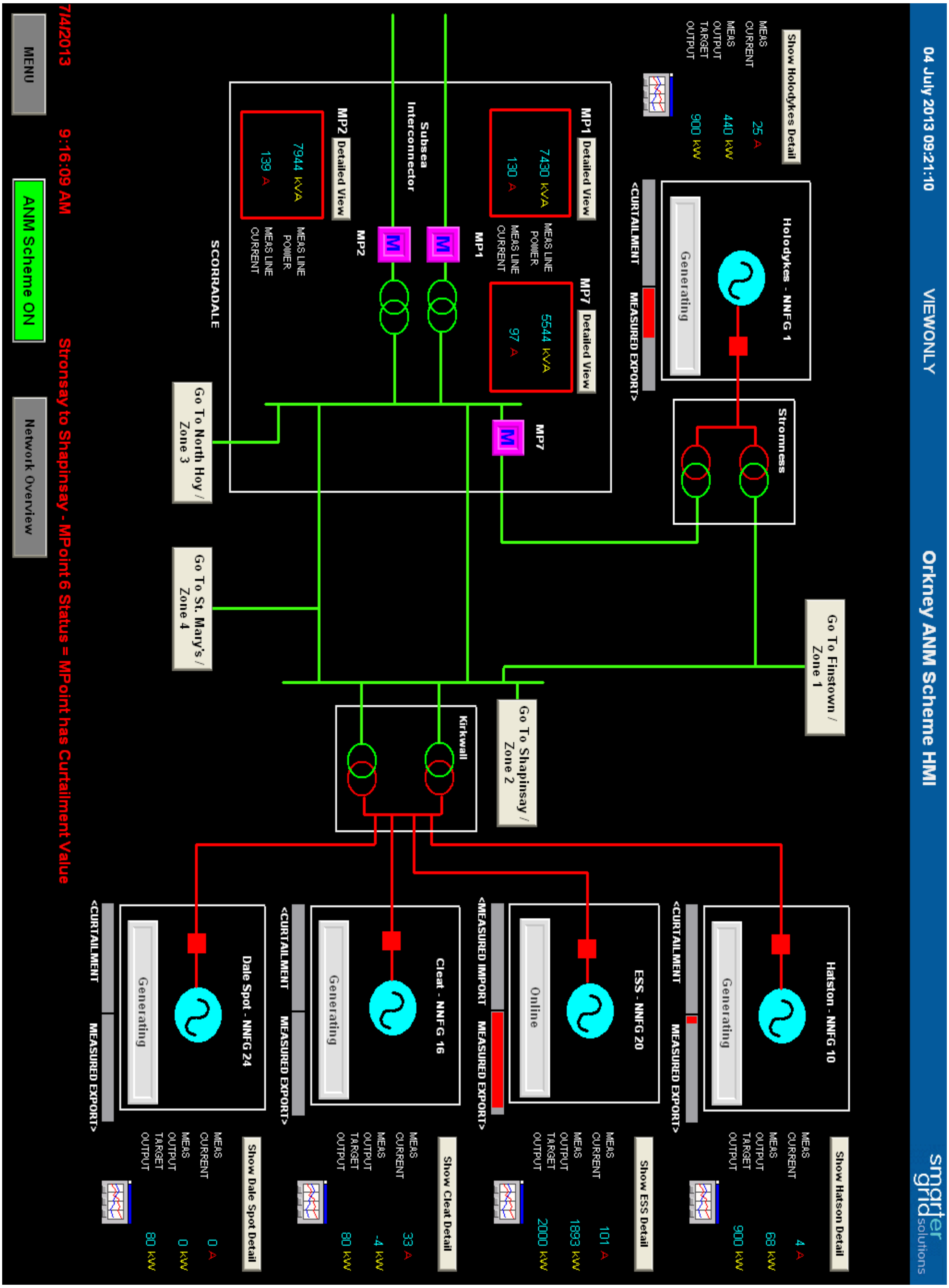

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Appendix II
Billing Rules

Billing Rules

- If ESS is declared as available for any availability period, non ANM requested import is not allowed. Non compliance will result in the ESS being tripped off by the ANM scheme.

- Entry requirement to Availability Periods are Nominal Available Capacity = Stated Capacity unless there was export capacity < the Stated Capacity of the battery I.e. Availability Period 1 to 2 experiences export constraint meaning that Nominal Available Capacity = 0 at start of Availability Period 2 or the ESS leaves Availability Period 3 full due to ANM requests or leaves Availability Period 3 with Nominal Available Capacity < Stated Capacity but due to import requests

- System will stop receiving availability payments, during Availability Period 1, 2 or 3, from the moment an unavailable signal is received from the ESS or the moment a Stated Capacity non compliance is identified

- ESS is to be sent a minimum import of 400kW due to system characteristics

- Availability payment is £/kWh. So if the ESS only has a portion of the 500 kWh available they receive only a portion of total payment if they were fully available. This amount of availability is what's notified to SSEPD the day before. It does not mean that the availability payment reduces as the ESS fills up during the Availability Period.

- Active payment will be equal to the amount that has been requested to be imported.

- ESS must be able to deliver stated capacity. If they are found to fill up quicker that what they have notified the day before as their Stated Capacity then they will lose their availability payments

- ANM system will be separate to Availability Notification System (ANS). ANS will state what APs the ESS will be available during, also what the STATED CAPACITY is.

- The ESP will not receive Availability Payments if the ESS is technically unavailable or unable to receive charge as a result of being fully charged, with the exceptions set out below.
- When the Applicant's Installation has become fully charged as a result of continuous charging instructions received via the ANM, and has been unable to discharge subsequently due to export constraints the Applicant will be entitled to receive a proportion of the relevant Availability Payment calculated as follows:

- When the device is fully discharged the NAC would be set to the storage capacity of the Applicant's Installation (in effect the difference between the maximum recommended charge, ~90%, and the minimum recommended charge, ~10%, of the device). When the NAC > 0, the Applicant will not receive any Availability Payment if it is unable to meet an instruction to charge via the ANM.

- When the NAC = 0 (ie the device is notionally fully charged), the Applicant receives 50% of the Availability Payment if it is unable to meet an injection instruction, or 100% if it is able to meet a injection instruction having discharged the system following the Applicants decision to do so.

Term Quantification

The NAC is calculated as follows:

Nominal Available Capacity = Stated Capacity – Import + Export

where,

-Import + Export >= 0

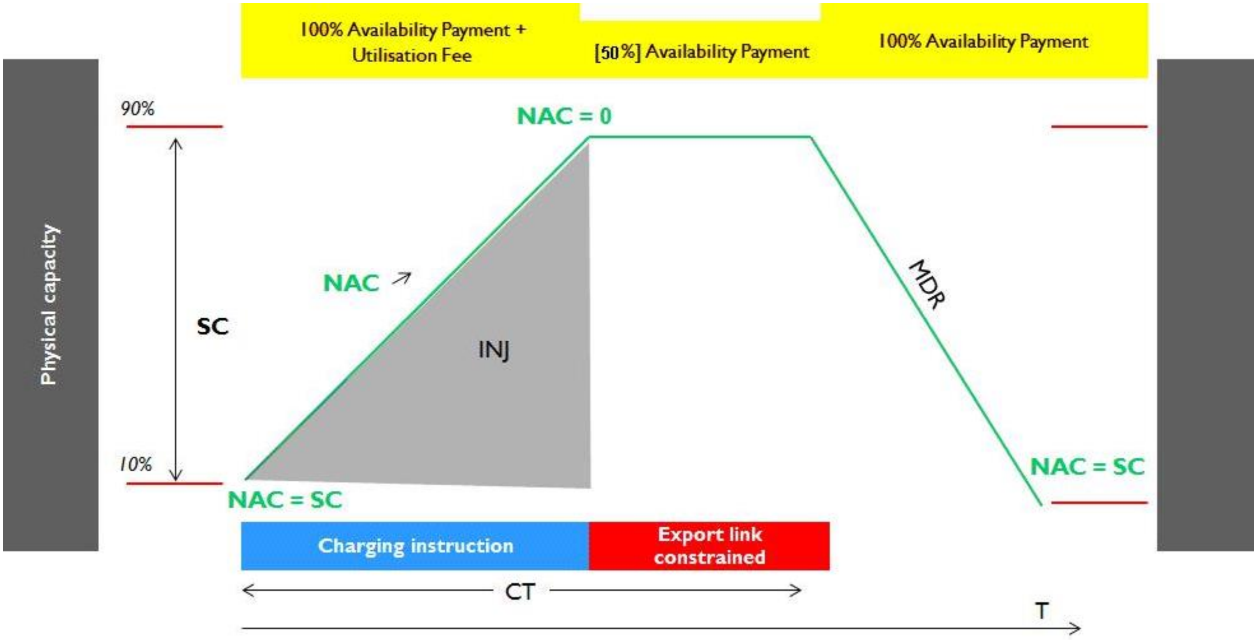
where,

Stated Capacity = Capacity of the Applicant's Installation

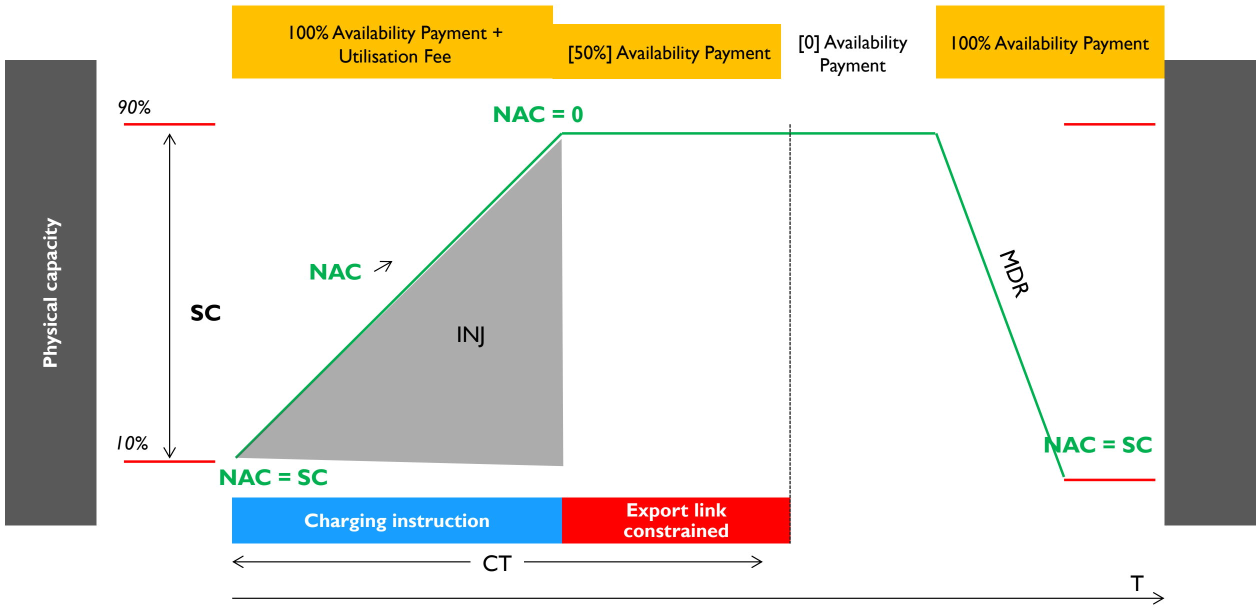
and

Import and Export = All Imports/Exports of units of electricity to the ESS as registered at the 11kV metering circuit breaker

The concept is illustrated in the figure below. The NAC is shown as the green line. At the start of the period, in this example, the Applicant's Installation is discharged. It receives a charging instruction until the device is full. It receives its full Availability Payment during this period and is also paid the Active Payment for the volume of electricity injected. Once the NAC = 0, but the Applicant's Installation is unable to discharge due to a Distribution System constraint, the Applicant's Installation receives [50%] of the Availability Payment. Once the constraint disappears, the Applicant's Installation receives the full Availability Payment and the NAC increases at the Minimum Discharge Rate until it is equal to the SC.



The concept is further illustrated in the figure below. Using the same concept as the figure above, in this illustration the Applicant's Installation is not discharged after the constraint on the export is link is removed. For the period until the NAC > 0 of the Application's Installation, Availability Payment Adjustment is set to 100% implying a zero Availability Payment for that period.



Appendix III

Battery Cost References

Lithium-ion battery costs are estimated based on publicly available £/kWh cost from peer-review literature, consultant publications and other actual projects. The Base Case cost is based on the UK Power Networks installation of a 6 MW 10 MWh lithium-ion battery at Leighton Buzzard as a LCNF Tier 2 project. Using this as a present day price the rate of decrease in battery prices as projected by BNEF is applied to get a forward looking battery price curve. The main sources referenced are summarised in **Error! Reference source not found.**, with additional references included for information in **Error! Reference source not found.**.

	Li-Ion Battery Cost (£/kWh)				
Year	**BNEF (2011)[26]**	**McKinsey (2012)[27]**	**Grünewald *et al.* 2011[28]**	**Element Energy Range (2012)[29]**	**UKPN Leighton Buzzard Installation (2013)[30]**
2011	-		311	514	
2012	558	341			
2013	490				650
2014	384				
2015	279			294 - 360	
2016	236				
2017	217				
2018	186				
2019	155				
2020	136	124		179 - 273	
2021	-				
2022	-				
2023	-				
2024	-				
2025	-	99		145 - 213	

[26] Bloomberg New Energy Finance, (2011), Grid-Scale Energy Storage: State of the Market (Link)

[27] McKinsey and Company Insight (July 2012) (Link)

[28] "Grünewald *et al.* (2011) -The role of large scale storage in a GB low carbon energy future" An average of multiple sources

[29] Element Energy, Cost and Performance of EV Batteries for The Committee on Climate Change (March 2012)

[30] UK Power Networks (UKPN) LCNF Tier 2 SNS (Link)

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Additional Battery Cost References
http://batteryuniversity.com/learn/article/cost_of_power
http://www.lowcarbonfutures.org/sites/default/files/Li%20Battery_final.pdf
http://www.greentechmedia.com/articles/read/Southern-California-Edisons-8MW-Li-ion-Battery-for-Wind-Power-Storage
http://web.mit.edu/sloan-auto-lab/research/beforeh2/files/PHEV%20costs.pdf
http://energy.gov/sites/prod/files/piprod/documents/Chiang_US-EU_Workshop_StorageTechnologiesPowerGrids_for_posting.pdf