RIIO-T2 Output & Incentives

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Approach and Examples to Mitigating the Energy Not Supplied (ENS) Risk to Consumers

SP ENERGY NETWORKS

1 Scope of this Paper

This paper is intended to provide an overview of the approach SP Transmission plc (SPT) applies to mitigate the risk to consumers of experiencing a loss of supply due to an event on our transmission system. Examples of real projects are included to demonstrate how our approach is implemented as part of our business as usual activities.

The purpose of the document is to respond to questions from Ofgem raised in respect of the Energy Not Supplied (ENS) reliability incentive that is in place for RIIO-T1. It is hope this information will inform development of the reliability incentive for RIIO-T2.

The information has been gathered with the help of key business experts in our Operational Control Centre and Engineering Design functions, and reviewed by RIIO-T2 workstream leads.

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2 The Energy Not Supplied (ENS) Incentive

The ENS reliability incentive incorporates a baseline target for our annual ENS at 225MWh. Performance above or below this level incurs a reward or penalty based on an incentive rate of £16,000 per MWh. There is a collar which limits the maximum penalty to 3% of allowed revenues.

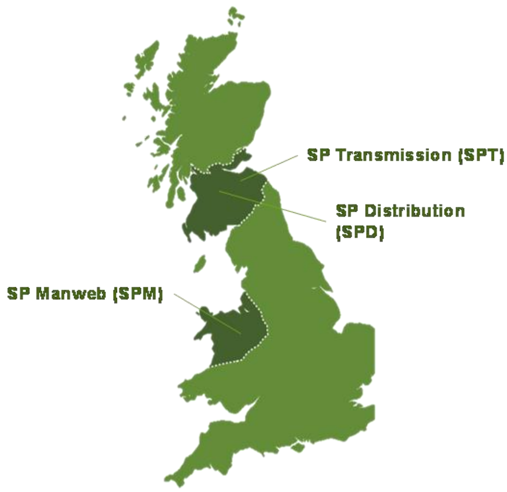
Our Licence requires that SPT must have in place and maintain a Reliability Incentive Methodology Statement that sets out the methodology used to calculate the volume of energy not supplied arising from each Incentivised Loss of Supply Event. SPT must use reasonable endeavours to apply the methodology that is set out in the Reliability Incentive Methodology Statement.

3 Our Approach to ENS Mitigation

3.1 The SPT Transmission Network

The particular situation and configuration of our network is important to our ENS risk mitigation approach.

Our Transmission Network comprises approximately 4000 circuit kilometres of overhead line and cable and 154 substations operating at 400, 275 and 132kV supplying approximately 2 million customers and covering an area of 22,951 square kilometres. It is connected to the SHE Transmission System to the north, the NGET Transmission System to the south and the Northern Ireland Transmission System via an HVDC interconnector.



There are 9 major demand customers supplied directly from the SP Transmission System with the majority of the load being taken by approximately 2 million customers connected to the SP Distribution System via 14.4GVA of installed transformer capacity. There is approximately 6.3GW of directly connected and Large Embedded generation capacity connected in the SP Transmission area, including 33 power stations directly connected to the SP Transmission system.

3.2 ENS Mitigation in Outage Planning Processes

To carry out any work on our transmission assets, whether upgrading or extending our network to connect new customers; maintaining existing assets; or repairing faults, a system outage is required. An outage is the switching out of an asset to de-energise it and making it safe for staff to come into proximity and work by earthing it to ensure it does not become inadvertently energised. This work may then involve disconnection of the asset from the network or allow modification or maintenance to be carried out. The process to identify the need, extent and duration of an outage sequence can be long and complex and is a core element of our transmission business.

The transmission system in GB is designed and operated to meet the NETS SQSS standard[1]. Section 5 of the standard explains the operation of the transmission system under "prevailing" conditions which will therefore normally include planned outages and unplanned outages.

Consumer Impact of ENS

The impact of an outage on our transmission network can be felt by directly connected transmission customers and distribution connected consumers alike. The ENS incentive is limited to demand customers and is not sensitive to diffentiate between these types of customer. Typically a directly connected transmission customer is restored quickly in the event of a fault. Distribution connected customers may be exposed to longer duration outages due to the reduction in design contingency at lower voltage levels.

For example, a transmission outage of a circuit supplying a GSP substation reduces the security of supply to the GSP by half and the NETS SQSS allows for this risk. A GSP is typically designed with sufficient security to comply with the SQSS by connection of two circuit infeeds. This is the normal operating condition, and sufficent capacity is provided such that the loss of one in-feed will be supprted by the second ciruict without interruption to any supply. In a planned outage scenario, one circuit is withdrawn from service to carry out work and the GSP is connected only by the remaining circuit. Should a fault occur on this circuit during the planned outage of the other circuit, the supply to the entire GSP will be lost.

Our ENS mitigation ensures that in this event our distribution customers can be restored as quickly as possible. This is the benefit the current ENS incentive supports.

An outage can only be taken with the approval of the GB Electricity System Operator (NGESO) and this is achieved according to rules set out in the **System Operator Transmission Owner Code (STC)**[2] and the Network Access Policy (NAP). NGESO has final approval of a planned outage because it has responsibility for the flow of energy across the GB transmission system to balance generation and demand effectively in real time. An outage of a transmission asset can disrupt that flow and reduce the security of supply for consumers. NGESO will assess the security of supply risk to ensure the national security of supply standard (NETS SQSS) is maintained. For all outages on Transmission system we will further review the increased risk of supply to customers being lost above and beyond what is required by the NETS SQSS.

This risk of suffering a loss of supply can increase when we take an outage on a transmission asset. This can be an overhead line or cable circuit, a whole substation or single asset at a substation such as transformer, circuit breaker or protection system. This risk is experienced by our directly connected

[1] https://www.nationalgrideso.com/sites/eso/files/documents/NETS%20SQSS%20V2.3.pdf
[2] https://www.nationalgrideso.com/codes/system-operator-transmission-owner-code

transmission customers and distribution connected customers who are supplied though our grid supply point (GSP's) substations where the transmission /distribution interface exists.

3.3 ENS Mitigation in Investment Planning and Approval Processes

The process of assessing the ENS risk is incorporated within our **investment approval process**. This process follows a staged approach to investment approval, where investments are approved at distinct points (gates) throughout the process. Initial concept, technical design and financial approval are achieved at different stages, for a number of reasons; including amongst other things:

- a separate concept and technical approval stage ensures that only those projects that have viable solutions (including meeting strict safety criteria) have resources allocated to develop full technical specifications;

- a separate approval for the release of risk mitigation costs ensures that these are being utilised appropriately and provides visibility as to how project expenditure is being managed; and

- while financial re-approval may not be required, having a separate approval stage provides an opportunity to challenge the underlying reason(s) for increases in project expenditure and draw out 'lessons learned' for application to future projects. of any capital investment

Throughout this process, at each stage gate, all project risks and mitigating actions are considered, evaluated and determined as to whether these are sufficient. Specifically, as part of the Technical Approval process, projects involving transmission outages are assessed for the ENS risk. Where this is identified, ENS mitigation is achieved through appropriate contingency actions. These mitigating actions vary according to the extent of the risk and will be incorporated within the project development.

ENS Risk

The extent of the ENS risk will be assessed in terms of the monetary value based on the ENS incentive mechanism. Customer Minutes Lost (CML) and Customer interruptions (CI) impact are also assessed as these are incentivised under the ED1 price control and our SP Distribution licence. As well as the financial impact on our business in respect of ENS, CML or CI, other key metrics considered are the "Emergency Return to Service" (ERTS) and Emergency Restoration of Supply (EROS) values. These provide a better view of the impact on customers, should a loss of supply occur, is the length of time it takes to achieve the restoration of supply. Under the ED1 distribution licence (Guaranteed Standards), targets for EROS have reduced from 18 to 12 hours in the current price control period. Achieving improved restoration times is valued by consumers and is explicitly considered in our ENS mitigation approach.

This is important as ENS is based on MWh. If the customers primarily affected are multiple distribution connected domestic consumers, the associated MWh value can be considerably less than if a single large industrial transmission connected customer will incur. Yet the impact on that individual customer can be significant, especially if they are vulnerable customers.

As the Electricity Networks business in Central and South Scotland, the reputational impact of a loss of supply experienced by our customers, whether from a transmission incident or distribution incident, is largely immaterial to them. Therefore any risk of loss of supply from a transmission related event needs to consider the impact on our distribution customers.

The mitigation of risk can be achieved in different ways and will be bespoke for each project and requires project specific assessment and actions for every outage. The main technical document that captures system outage requirements and risk assessment is our System Construction Authorisation (SCA) document. A SCA is prepared for each project and is reviewed by multiple parties with technical, financial and safety responsibilities. SCAs are prepared by our Engineering Design teams. A **job description** for the Engineering Design role is provided alongside this report. Final technical approval for a project is made at the Transmission System Review Group (TSRG) which meets monthly.

3.4 ENS Mitigation in Construction and Operational Processes

The design phase of a transmission construction project typically start years in advance of outages being taken and consideration of ENS mitigation is embedded throughout this process. As the project moves through its life cycle and into the construction phase focus and mitigation of ENS risk continues and develops. The assessment of specific outage requests is carried out by our Operation Control Centre Planning teams including engagement with NGESO to secure their formal approval of an outage. The assessment will include challenge of the proposed ENS mitigation measures, request for evidence that these measures are in place and suggestions of further measures that might be undertaken. A weekly risk review is conducted by Senior Management to assess all operational risks facing the business. An example of a recent **network risk report** is provided which highlights this and demonstrates the fundamental place Customer impact and ENS have in our risk management processes. In addition weekly engagement by Operational Control room staff and each of the six Regional District that our distribution business comprise, is conducted to notify and explain the transmission outages and risks that effect each District.

To demonstrate this process and provide specific evidence examples of two live projects are provided in section 4 as follows.

4 Examples of ENS Mitigation in Live Projects

Two projects have been selected as typical examples of how mitigation has been implemented through the project life-cycle. These are two of multiple projects that SP transmission are delivering to achieve their RIIO-T1 outputs and the principles illustrated in these are replicated throughout all our portfolio of projects. Over 1500 outages are taken annually by SPT and ENS mitigation is a risk consideration in every outage.

4.1 Johnstone GSP Substation 132/33 kV Transformers Replacement

This Johnstone Project SCA is the technical that describes this project and explains how all civil, switchgear and protection works at Johnstone 132/33 kV Substation will be carried out for the replacement of power transformers). Both existing Grid T1 and T2 power transformer are 60MVA 132/33kV units, which were installed in 1965. These transformers have been identified as having reached end of life and require to be replaced in advance of failure and are included in our RIIO T1 non-load plan as required outputs to deliver in this period.

Johnstone GSP 132/33kV Substation has no 33 kV interconnections (which would deliver the capability to provide alternative supply from another part of the network) with any other GSP, which leaves it vulnerable to faults on the transmission system. The available 11 kV interconnection is only capable of picking up around 20% of the demand at Johnstone GSP. The proposed approach to the work is therefore to install the new Grid Transformers off-line, with the existing Grid Transformers connected to the transmission system, as far as practicable. This will reduce the lengths of the outages and the inherent customer risk. The works are planned in such a way as to minimise outage timescales, by carrying out the offline construction for both replacement T1 and T2 transformers. The replacement T1 Transformer and associated equipment will be installed in a new location within the site, enabling works for T1 to be completed offline. The replacement T2 transformer and associated equipment will utilise space vacated by T1 transformer, allowing these also to be offline built. The aerial photograph below shows the layout.

The project was designed in 2013 and the risk of ENS is mitigated by delivering an offline build. Additional land was available in the site which subject to planning permission being secured, would allow the new transformers can be installed before removing the existing transformers. The work involved at each stage was designed to meet an 18 hour ERTS with no further contingencies required. The Technical approval for this project was predicated on this risk mitigation. **The formal IP2** technical approval paper documenting this project is provided as evidence and page 3 of this document confirms that:

> *"The carrying out of these works offline will enable the project to be completed without introducing a significant single circuit risk or costly contingencies"*

Section 9.3 of the Johnstone GSP SCA outlines the 9 system outages that are involved to deliver the project. Each outage is explained in detail in section 13 and each outage has an ERTS forecast and contingency arrangements described. Page 42 section 13.2.2 for example explains the ERTS for the first outage as being limited to 2 hours. Section 13.2.3 on page 45 however has an ERTS of 18 hours, the worst case for the project. The contingency provisions are described as follows:

> *"None. The works have been planned in order to minimize the ERTS to 18 h. All works shall be carried out without modifying the existing post insulators, busbars, and down lead, until the last moment, i.e., post insulators and the portion of the busbars that don't imply any connection to the existing arrangement shall be installed at a first moment, without modification of those existing, so that it is possible to go back to the original stage, by removing tools and evacuating workers from the compound. The final connections to the new red phase arrangement (repositioning of the down lead, and connection of the droppers and clamps and last busbar portion) can be done in 18 h. The system is ready to be reconnected from the remote Substation".*
>
> The extent of the review of the proposed design is highlighted in appendix C which includes 67 different comments from various expert staff included in the assessment process. The risk of ENS and ERTS is a significant element of this assessment for example comments 63 to 67. Comment 67 highlights an estimated £5 million ENS penalty associated with the 18 hour restoration.
>
> The operational phase of the project ultimately commenced in 2018. The ENS risk highlighted above and ability to deliver an ERTS of 18 hours at worst was fully considered in advance of the actual outages. Further evidence of this is provided by the method statement prepared that describes the actions to deliver the **18 Hour ERTS at Johnstone**, in the event of a fault on the second circuit. The document provides details of the safe methods of working to achieve the ERTS at each stage of the project. For example, on page 6 the actions described are as follows:
>
> *ERTS OPTION 1*
>
> - *If ERTS is called before sequence #2 then the existing infrastructure can be relied upon to be returned to an energised state – duration expected to be maximum 5 hours to refit old downlead, remove PI & Structure and switch circuit in to service. Personnel available on standby to execute the above works are detailed below in table.*

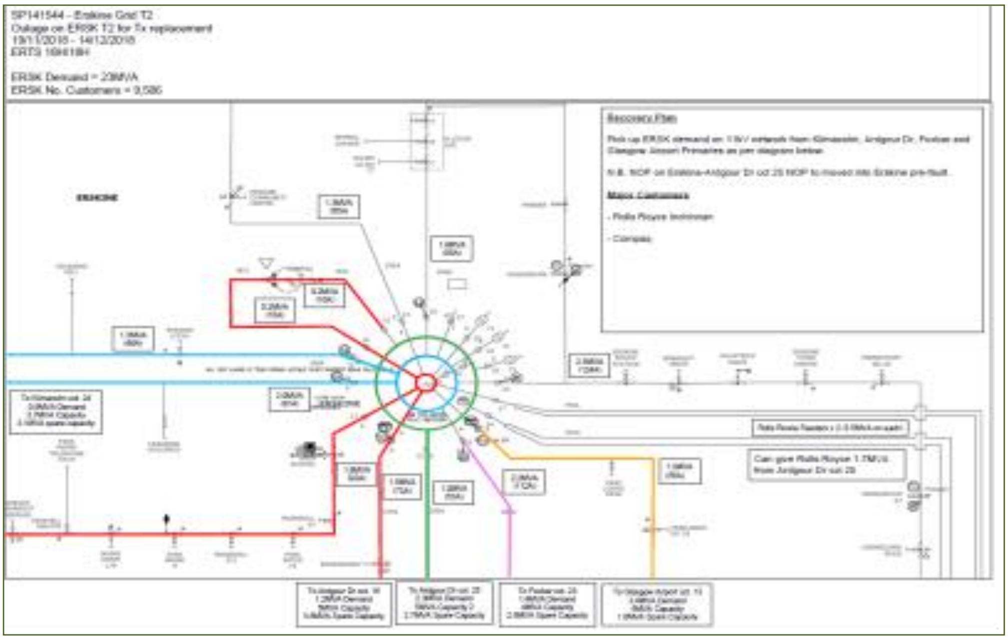
- *If ERTS is called during section #3 the site team will continue to install the new Downleads & Droppers to the new Anchor block, however, a temporary connection to the existing PI & Busbars can be made and only the above PI (#1) will need to be removed – duration expected to be maximum 7 hours*
- *Once #4 has commenced then the new build of Red phase including the temporary busbar section to the existing 113 disconnector will be made available to be energised – maximum duration expected to be 9 hours*

Ultimately this project is being successfully delivered and has not resulted in any loss of supply to consumers.

4.2 Erskine Grid T2 transformer replacement project

This project provides further evidence of ENS mitigation but compared to Johnstone (which had no interconnection) this GSP has the opportunity to use alternative supply routes from the connected 11kV (distribution network) to mitigate the risk of ENS and reduce ERTS.

The circuit diagram below highlights the ability to secure some supplies to Erskine GSP in the event of a fault during the outage window.



The circuits that have been coloured are those that can provide interconnection from other parts of the network to restore some of the consumers Erskine GSP substation normally supplies. Not all the circuits are coloured highlighting that Erskine does not have full switchable recovery and a permanent fault on the 132kV overhead line in-feed circuit will result in the loss of some supplies. Additional contingency to achieve full customer restoration has been identified by converting the second 132kv overhead line in-feed circuit to run temporarily, as a 33kV circuit by connecting it using 33kV cable connections to the 3kkV network.

The **outage request form** which is the internal document from our delivery teams to the operational control room, confirms this 132kV contingency arrangement are to be achieved as follows:

> *"This connection is a temporary arrangement which does not include the replacement of disconnectors 203,213 & 403. The ERTS for GT2 is Oncom but in the event of N-2 the contingency circuit can be commissioned in 18Hrs"*

This is a typical example of ENS risk mitigation achieved through a contingency arrangement and requires significant preparatory work:

- The 33kV breakers at the supporting GSP substation are to have their protections schemes altered to enable the overhead line circuit to be energised at 33kV rather than its normal operating voltage of 132kV.

- 33kV cables will be laid from these circuit breakers out to the post insulator structures at the overhead lines where the jumpers/downleads connections can be made to connect the cables to the lines.

- In the event of the fault, proximity switching will be carried out to allow for the jumper connections to be made and the protections switched in for the circuit to be energised as a 33kV interconnector restoring supplies.

- The materials for the jumpering to connect the cables to the overhead lines will be measured and stored on site at each site in advance.

Evidence of the focus at the operational stage on ENS mitigation is emphasised by the correspondence between our OCC Planning and the **construction teams.** This demonstrates a drive to achieve a 12 hour EROS target above and beyond the ERTS capability of 18hrs:

> "*Given that we will be in mid-winter, with us likely only being able to pick up 3-5MVA of the 30MVA Erskine GSP (10% to 20% of the customers), it important that we have the restoration plan as robust as possible. Personally I believe that a <12hr RTS could be achieved if all the preparations were in place, but as I don't have visibility yet of the details, I suspect the 18hrs currently may be optimistic dependant on the points below. Will all the points below be in place prior to the Grid T2 outage?*
>
> - *33kV Cables terminated into switchgear at Erskine and Devolmoor*
> - *33kV Cables terminated onto structures at Erskine and Devolmoor*
> - *Protection Configuration tested / available (applied??) to 33kV feeder breakers at Erskine and Devolmoor*
> - *OHL Jumpers, (previously cut to size) on site*
> - *Clarity on day / night availability of key staff (Contractors / SPEN)*"

Additional evidence from the Erskine project of the focus on customers connected at distribution with the **correspondence** documenting the challenge from the operational control room staff responsible for approving the outage request to the deliver teams who are submitting the request as follows:

> *"I recognise and support the need to proceed with these works but to gain my unconditional approval, there are a few outstanding activities that need to be completed (some of which I understand are being worked on). These are (not limited to);*
>
> redaction
>
> [redacted]
>
> 2. ***A detailed plan outlining who and what needs to be done to minimise the ERTS, including;***
>   *a. contact details of critical resources both NWD and OOO (who needs to do what and when); we cannot afford to 'waste' a number of hours trying to contact critical resources (e.g. 9pm on a Saturday evening)*
>   *b. the sequence of activities and expected (committed?) timescales*
> 3. ***A detailed plan of the 11kV switching that would be undertaken to manage partial recovery, including;***
>   *a.t he dispatch of resources from my team to exact locations to assist*
>   *b.the effect this would have?*
>   *c.do we propose to 'rota shed' customers during the recovery period?*
> 4. ***How we propose to manage customers during this period, should we lose the 132kV in feed?***
>
> *Clearly, we will assist in supporting these works as we move towards the outage but given the scale of the issue, albeit at low risk, I think it's vital that we undertake this assessment and document the associated plans so everyone is clear on their responsibilities should we lose the grid infeed."*

This is another typical example of the focus we have on mitigating the risk of an ENS event on distribution connected customers and domestic consumer. This is over and above the obligations we have to meet NETS SQSS standards and the attention or responsibility for managing energy flows on the main interconnected transmission system NGESO would ask us to consider for them to approve our outages.

5 Conclusions and Recommendations

- Maintaining security of supply and minimising the impact of a loss of supply is fundamental to our business. Consumers benefit from the ENS mitigation approach we implemented which is embedded throughout our design, construction and operational processes.

- We have a whole system approach to our ENS mitigation considering the impact and risk across our transmission and distribution businesses to achieve optimum outcomes for our customers.

- The ENS reward works well to dive this approach and should be maintained as an explicit asymmetric incentive. The current collar of 3% of allowed revenue is punitive and therefore focuses attention on our design and delivery projects that require transmission outages, as evidenced in this paper. The opportunity for reward provides an incentive to go beyond minimum NETS SQSS requirements.

- Funding this mitigation activity as baseline would risk losing the benefit a penalty/reward achieves to spread activity across all projects according to risk. Including a forecast cost associated with this work could allow the focus on efficient costs to dominate decision making. The move to a baseline funding effectively changes the incentive from competing for a prize in every project to optimising costs

- The proposal to include embedded generation into calculations to make ENS more representative of consumer impact will not improve on the risk mitigation activities we provide already. Incorporating embedded generation into ENS targets would be challenging:

    - It will be very difficult to get hold of metering information.
    - The ENS target calculations would be more complex and volatile relying on assumptions.
    - Metering information can be flawed as half hourly readings are an average and we would need real time information to identify levels of embedded generation when a fault occurs

- An alternative to including an embedded generation factor could be the use of CI/CML. This incentive mechanism exists in distribution and reflects the impact on consumers of a loss of supply from transmission fault arguably more than the volume of energy lost. This may also support the benefits of a whole system approach proposed for RIIO-2.