Transmission and Distribution Interface 2.0 (TDI)

Bid Document to Ofgem

Contents

Section	1	Project Summary	4
	1.1	Project Title	4
	1.2	Project Explanation	4
	1.3	Funding licensee	4
	1.4	Project description	4
	1.5	Funding	5
	1.6	List of Project Partners, External Funders and Project Supporters (and value of contribution)	5
	1.7	Timescale	5
	1.8	Project Manager Contact Details	5
	1.9	Cross Sector Projects (only complete this section if your project is a Cross Sector Project, ie involves both the Gas and Electricity NICs).	6
Section	2	Project Description	7
	2.1	Aims and objectives	7
	2.2	Technical description of project	13
	2.3	Description of design of trial	19
	2.4	Changes since Initial Screening Process (ISP)	20
	2.5	References	20
Section	3	Project Business Case	21
	3.1	Executive summary for the business case	21
	3.2	The Project Definition	21
	3.3	Background Information	21
	3.4	Cost-Benefit Analysis – Today’s Model Assumptions	22
	3.5	Cost-Benefit Analysis – Innovation Model Assumptions	23
	3.6	Limitations	25
	3.7	References	25
Section	4	Benefits, Timeliness and Partners	26
Section	5	Knowledge Dissemination	35
	5.1	Learning generated	35
	5.2	Learning dissemination	36
	5.3	IPR	40
Section	6	Project Readiness	41
	6.1	TDI 2.0 Project will start in a timely manner	41
	6.2	Senior management commitment	42
	6.3	How the costs and benefits have been estimated	42

6.4	Measures employed to minimise the possibility of cost overruns or shortfalls in Direct Benefits	42
6.5	Accuracy of information	43
6.6	TDI 2.0 Project will deliver learning irrespective of the take up of low carbon technologies and renewable energy	44
6.7	Processes are in place to identify circumstances which could affect successful delivery of the project	44
Section 7	Regulatory Issues	45
7.1	Data Confidentiality	45
7.2	Balancing and Settlement Code	45
7.3	DNO revenues	46
7.4	Future of the Smart Grid	46
Section 8	Customer Impact	47
8.1	Existing generation customers	47
8.2	Future generation customers (no current offer)	47
8.3	New generators (outstanding offer)	47
8.4	Customer engagement and education	48
8.5	Customer Interruptions	48
8.6	Learning and Dissemination	50
8.7	Managing Customer Enquiries	50
Section 9	Successful Delivery Reward Criteria (SDRCs)	51
Section 10	List of Appendices	53
Appendix 1	Electricity NIC Financial Benefits	54
Appendix 2	Full Submission Spreadsheet	56
Appendix 3	Maps and diagrams	57
Appendix 4	Project Plan	60
Appendix 5	Project Risk Register, Risk Management & Contingency Plans	62
Appendix 6	Technical Description	66
Appendix 7	Project Organisation	77
Appendix 8	Project Partners	78
Appendix 9	Work Stream Descriptions	82
Appendix 10	Cost Benefit Analysis	91
Appendix 11	Letters of Support	97
Appendix 12	Glossary	100

Project Code/Version Number:
NGET_UKPN_TDI2.0/V.01

Section 1 Project Summary

1.1 Project Title	Transmission & Distribution Interface 2.0 (TDI 2.0) Project
1.2 Project Explanation	The TDI 2.0 project aims to develop technical and commercial solutions to maximise the use of distributed energy resources (DER) to resolve transmission voltage constraints. In addition, it will develop a Distribution System Operator (DSO) route to market for such solutions in a coordinated manner with the existing System Operation functions.
1.3 Funding licensee	National Grid Electricity Transmission
1.4 Project description	**1.4.1. The Problem(s) it is exploring** The transmission and distribution network in the South East of England is at the limit of capacity for both importing and exporting power from the rest of the transmission system. Further generation connection in the transmission network can be achieved by either significant investment in the infrastructure or with innovative solutions. The latter aims to achieve the same results as the infrastructure approach, but with significant savings. **1.4.2. The Method(s) that it will use to solve the Problem(s)** The project will focus on the following methods: • A technical solution based on information and communication technologies (ICT), which interacts with all market participants to facilitate the provision of services by the DER to National Grid Electricity Transmission. • New commercial arrangements between DER, UK Power Networks and National Grid Electricity Transmission, which ensures that they are sustainable over time. • Customer and market engagement which ensures that the solution is open to existing and new participants. A coordination framework for secure grid operation which will deliver efficient coordination across SO and DNO investment planning, operational planning and real-time horizons. **1.4.3. The Solution(s) it is looking to reach by applying the Method(s)** By creating a regional power market including DER in the South East, the SO will be able to tap into a previously unexploited resource. It will

	validate mechanisms by which multiple services and multiple constraints can be managed without conflicting with one another. Furthermore, it will create a whole system approach to addressing challenges on the transmission system by using resources on the distribution network to provide dynamic reactive support and create benefits for end consumers. The value of services provided by DER to National Grid Electricity Transmission via UKPN coordination will amount to £29m by 2050 savings for customers and will enable the distribution network operator to connect further 3720MW by 2050 of generation in the area. The GB wider rollout of this method could deliver £412m savings by 2050.

1.5 Funding

1.5.1 NIC Funding Request (£k)	£7,970.435	1.5.2 Network Licensee Compulsory Contribution (£k)	£896.399
1.5.3 Network Licensee Extra Contribution (£k)	£603.598	1.5.4 External Funding – excluding from NICs (£k):	
1.5.5. Total Project Costs (£k)	£9,560.113		

1.6 List of Project Partners, External Funders and Project Supporters (and value of contribution)	Project Partners: National Grid UK Power Networks Technical Partner Aggregators Customers External Funders: TBC Project Supporters: Customers/ Aggregators/ Academia

1.7 Timescale

1.7.1. Project Start Date	03/01/2017	1.7.2. Project End Date	30/12/2019

1.8 Project Manager Contact Details

1.8.1. Contact Name & Job Title	Dr. Biljana Stojkovska	1.8.2. Email & Telephone	biljana.stojkovska@nationalgrid.com 01926 65 4696

	Smart Grid Project Manager	Number	(mobile:07826 944782)
1.8.3. Contact Address	National Grid, National Grid House, Warwick Technology Park, Warwick, CV346DA		

1.9 Cross Sector Projects (only complete this section if your project is a Cross Sector Project, ie involves both the Gas and Electricity NICs).

1.9.1. Funding requested the from the [Gas/Electricity] NIC (£k, please state which other competition)	N/A
1.9.2. Please confirm whether or not this [Gas/Electricity] NIC Project could proceed in the absence of funding being awarded for the other Project.	N/A

ofgem

RIIO NIC NETWORK INNOVATION COMPETITION

Section 2 Project Description

The TDI 2.0 project aims to address multiple constraints on the transmission network and provide additional network capability for the distribution network. To achieve this, it will develop technical and commercial solutions to maximise the use of distributed energy resources (DER) to resolve transmission voltage constraints. It will also develop a Distribution System Operator (DSO) route to market for such solutions in a coordinated manner with the existing System Operation functions. Ultimately, it will create financial benefits for consumers by saving from £1m by 2020 to £29m by 2050 creating 2604MVA network capacity to enable the distribution network operator to connect a further 3720 MW of distributed generation in the area by 2050. The financial savings accumulated to 2050, if rolled out across the 59 sites in Great Britain, would amount to £412m.

2.1 Aims and objectives

2.1.1 The Context

The South East of England is an ideal location for renewable energy deployment. With plenty of sunshine and access to offshore wind, renewable energy resources in the area have developed significantly in recent years. As the largest electricity demand centre in the UK, London is committed to a low carbon transition (Mayor of London, 2011). The use of DER in the South East has the potential to help London get closer to this goal.

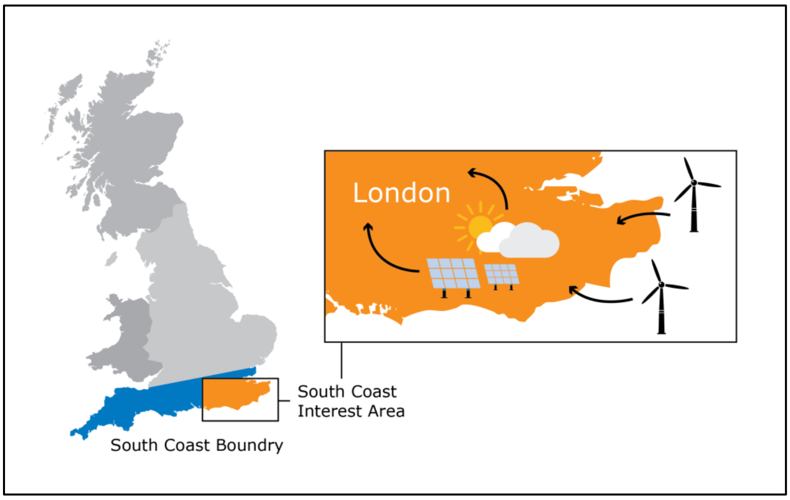


Figure 2.1 London and the South East

The South Coast transmission network runs through the south of England, as shown in Figure 2.1. In the South East of the network, the transmission system interfaces with UK Power Networks' distribution system at four grid supply points (GSPs). These are at Bolney, Ninfield, Sellindge and Canterbury, which are located in Sussex and Kent.

Apart from the growth in DER, the South East network is influenced by the presence of two interconnectors with Continental Europe, as well as plans for two more in the years to come. These interconnectors enable the buying and selling of electricity from the continent to meet demand and help keep the wholesale price low for GB consumers.

The South East network includes 2GW of peak domestic demand, and 5.5GW of large generation (National Grid, 2015), including:

- Shoreham Combined Cycle (420 MW), which is embedded within Bolney GSP
- Thanet Wind Farm (315 MW), which is embedded within Canterbury GSP
- Dungeness Nuclear Power Station (1.1GW), which feeds in at Dungeness
- London Array Wind Farm (630 MW), which feeds in at Cleve Hill
- IFA interconnector to France (2GW), which is connected at Sellindge GSP

Future interconnection and generation projects include:

- Rampion wind farm, comprising 400 MW connecting at Bolney GSP
- NEMO, a 1GW interconnector to Belgium, connecting in the Sellindge GSP area
- ELECLINK, which will interconnect a further 1GW to France in Sellindge GSP area

There is around 1.5GW (including Shoreham Power Plant and Thanet Offshore Wind Farm) of connected distributed generation (DG) on the distribution network and a further 0.3GW of contracted applications, so the South East represents an area with a significant amount of renewable generation. This is expected to increase over the coming years, due to the region's geographic position and excellent solar and wind resources.

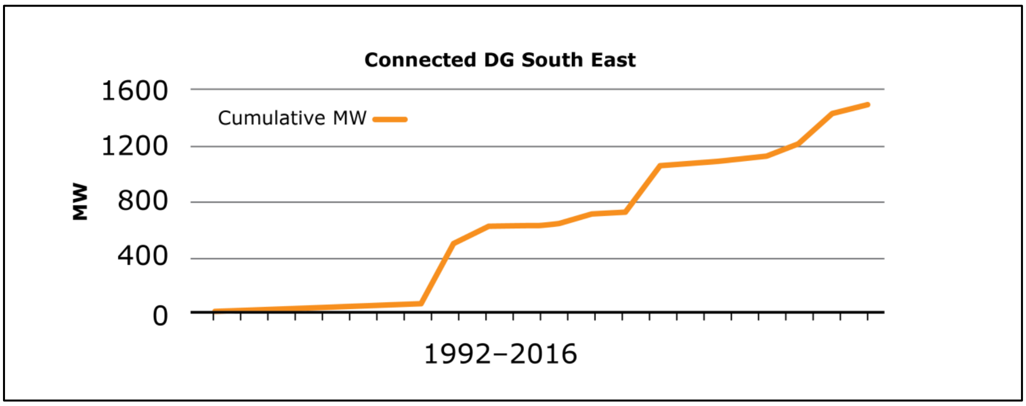


Figure 2.2 Distributed Generation growth

Renewable energy production on the distribution network in the South East, and imported energy from interconnectors, reaches London via East and West London.

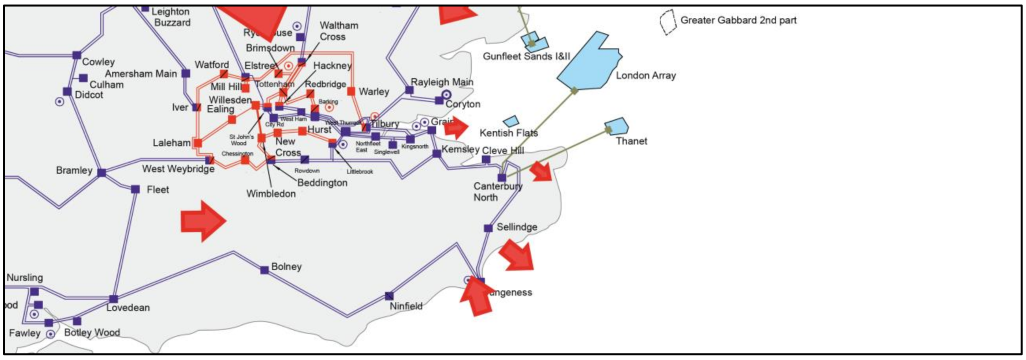


Figure 2.3 East and West routes from the South East

The East route connects London with the South East through transmission substations in Canterbury and Kemsley. The West route (long route) along the coast from Canterbury in East Kent goes to Bolney and Lovedean in South West England. This westerly route is 212km of transmission line, longer than the Scotland and England interconnector.

2.1.2 The Problem

The topology of the transmission system and generation mix, both in transmission and distribution networks, make this area of the system extremely challenging. Moreover, the growth of intermittent embedded generation in the South East, coupled with the interconnectors which can change from import to export within minutes, present a significant challenge in maintaining a constant balance between generation and load.

The System Operator (SO) is required to maintain the transmission system within normal safe operational limits. The SO currently uses a wide range of operational measures to make sure that voltage is kept within acceptable stability and compliance margins. These measures also make sure that energy in the system does not exceed equipment ratings.

As a result of the growing levels of intermittent renewable generation, National Grid Electricity Transmission is facing increasing operational challenges managing the voltage and thermal limitations for certain network conditions, while still being able to transfer energy to the country's load centres. Currently, this is not possible without constraining out-of-merit transmission connected generators, which increases system operational costs, and installing reactive compensation devices.

The ability of the transmission network to connect new generation and/or interconnectors is based in part on the available capacity during normal operation as well as limitations arising from planned or unplanned events on the network. National Grid Electricity Transmission has identified several constraints on its network in the South East which can affect operation and limit the amount of energy that can be transferred onto and around the system.

These issues, and the subsequent transmission constraints, can occur under different load-generation conditions and during various fault cases. These constraints are already biting and will only worsen when new interconnector projects are commissioned, as they will increase the complexity faced by the South East. The constraints, which are detailed in Appendix 6 of this document, include:

- Dynamic voltage stability: requiring reactive power delivery at short notice;
- High voltage: managing the voltage on the network during low load periods; and
- Thermal capacity: potentially leading to generation curtailment during the summer maintenance season.

These constraints are most prominent when a fault occurs on the route between Canterbury and Kemsley, which leaves only one long westerly route to deliver the South East's green energy to homes in London.

If such a fault occurs the consequences can be very serious for the system: given that the western route is a long radial line, and that a significant amount of power would need to be transferred at the time of the fault, the electrical characteristics of the circuit will lead to a rapid voltage drop across the network seconds after the fault.

If the voltage drop is not contained in time, this could lead to voltage collapse and, ultimately, a 'blackout' of the network. Even if a full collapse is averted, a dramatic deviation of the transmission voltage away from statutory limits can cause problems. Domestic appliances, building controls, elevators, air conditioning, and small DG, for example, might fail or trip, even though they are connected at a lower voltage on the distribution network.

To maintain a safe, economic and efficient network, both operational and planning limits have been set by National Grid Electricity Transmission. These dictate the amount of demand or generation that can be connected on the South East distribution network, and due to the rise in DG connections, these limits for generation are rapidly approaching. As the complexity of the network rises and the limits are exhausted, there is an increased risk that further DG connections might not be able to be accommodated in UK Power Networks' South Coast network.

One of the key roles for the DNO, besides maintaining security of supply, is to ensure that the network is accessible for all generating customers wishing to connect. Therefore, the constraints upstream in the transmission network have a clear effect on the distribution network and its customers.

If either operational or planning limits are reached, new measures would be needed to allow further generation to connect in the area. These measures have historically included costly projects, such as reinforcements of the network or new reactive compensation assets connected to the transmission system.

If reinforcing the network is not a cost-effective solution, operational procedures (such as generation curtailment) would be needed to mitigate the constraint. This would lead to unpredictable curtailments, which could increase significantly in future years. New generation customers wanting unconstrained connections will be subjected to long lead times or increased connections costs, as they might be asked to connect to other GSPs away from the area.

2.1.3 The Method

Due to the significant increase in DG connected to its networks, UK Power Networks has had extensive experience in the installation and operation of Active Network Management (ANM) systems, which are used to control DG with flexible connection agreements. These schemes allow DG to quickly connect to constrained areas of the distribution network and avoid large connection costs by accepting curtailment when network constraints are violated. UK Power Networks is currently developing a curtailment market approach to reduce the cost for customers and increase curtailment efficiency.

TDI 2.0 seeks to give National Grid Electricity Transmission access to distribution-connected resources to provide it with additional tools for managing voltage transmission constraints. The project will use an Distributed Energy Resource Management System (referred to as the TDI system in the this bid) which enables DER will be able to offer dynamic reactive power services to National Grid Electricity Transmission and active power reduction to both UK Power Networks and National Grid Electricity Transmission to resolve distribution constraints and offer flexibility upstream to the SO to manage transmission constraints.

UK Power Networks would act as one of the routes to market as well as technical coordinator, collating the available DER capabilities and costs and filtering them to satisfy distribution network constraints and making sure that any actions taken by National Grid Electricity Transmission, through the DER, do not undermine the operation of the distribution network. It would then present National Grid Electricity Transmission with details of the service availability and cost at each participating GSP. National Grid Electricity Transmission will then be responsible for looking at all available options and triggering the most economical solution for the constraints.

This approach, in parallel to the existing options for managing constraints, would provide National Grid Electricity Transmission another route to market. It would also test the level of coordination required to run the power system in the context where both the SO and DNO require flexibility in order to meet their core objectives efficiently. The TDI 2.0 method will evolve the roles of each market participant to a more dynamic system-wide coordinated approach to constraints.

Market Participant	Current roles	TDI 2.0 roles
SO (National Grid Electricity Transmission)	Balances the system and addresses transmission constraints with BMUs	Uses existing BMUs and distributed resources available by DNO for dynamic reactive response and active power re-dispatch to address transmission constraints
DNO (UK Power Networks)	Network operator and distributor of electricity to end consumers	Facilitates dynamic reactive response and ANM active power re-dispatch services to solve distribution and offer flexibility to SO for transmission constraints
DER	Imports or exports electricity and has a passive role in the system	Active participant in providing dynamic reactive response and active power services to resolve distribution and transmission constraints

The TDI 2.0 project will look to address both dynamic and steady state voltage issues by exploring two types of reactive power services coupled with active power reduction that seeks to alleviate thermal constraints on the system and optimises the reactive power services. The technical solution will look to employ an automated system coupled with control strategies to trigger and deploy each service without detriment to the distribution network.

By using distribution-connected resources to provide additional services to the transmission network, both UK Power Networks and National Grid Electricity Transmission will maximise the use of existing assets on the network. This service will include the creation of a regional reactive power market which will be delivered via the following routes: a) the DSO route where the DSO facilitates local participation; b) extension of the existing reactive power market which can includes DER. This extension to the SO reactive market capability with additional routes will be the first of its kind in Great Britain and help defer network reinforcement needs in the transmission system.

The project will include the development of a technical and commercial solution that will be complemented with an overall framework for coordination across SO, DNOs and market participants to avoid conflicting actions. The project will focus on the following methods:

- A technical solution based on information and communication technologies (ICT), which interacts with all market participants to facilitate the provision of services by the DER to National Grid Electricity Transmission. It also ensures that the services provided are not detrimental to the operation of the distribution network.
- A commercial solution to facilitate new commercial arrangements between DER, UK Power Networks and National Grid Electricity Transmission, which ensures that they are sustainable over time.
- Customer and market engagement which ensures that the solution is open to existing and new participants
- A coordination framework for secure grid operation which will deliver efficient coordination across SO and DNO investment planning, operational planning and real-time horizons.

Both SO and DNO coordinate activities through a number of existing interfaces and processes for operational and long-term planning. These current methodologies will continue to be employed and improved upon; TDI 2.0 seeks to build on these foundations and embed the solution into the business as usual by creating a day-to-day exchange of information that improves coordination between SO and DNO with the procedures and necessary process changes. The methods are summarised below:

	Technical	Commercial	Customer and market engagement	Coordination framework
Method	Provide reactive and active power services from DER to alleviate transmission constraints without undermining DNO network	Deliver a sustainable commercial solution	Provide a solution that is attractive and open to existing and new participants	Create an efficient coordination framework across SO and DNO

ANM has been explored by multiple DNOs as a tool to manage distribution constraints in areas with significant DG penetration and to allow more generation to connect without compromising the security of the network. TDI 2.0 is not another ANM solution; it takes the principles of exploiting embedded generation capabilities to assist in managing transmission voltage control (i.e. providing wider system services) within the limitations of the distribution network.

ANM Business as Usual	TDI 2.0 solution
• Focuses only on active power • Set up to address mostly distribution constraints • No market participation or remuneration	• Principle reactive power to assist the voltage transmission constraints • Active power management in offering flexibility upstream to transmission market participants • Innovative commercial arrangements

As the project develops, UK Power Networks will continue to facilitate connections by using existing flexible commercial arrangements. New customers will be encouraged to participate in this project and will be set up to ensure that while maintaining existing system limits they have the capabilities to add value to the system and to their investment.

2.1.4 The Trial

As detailed in Section 2.3 below, TDI 2.0 will employ a trial approach that will seek to demonstrate the effectiveness of the project deliverables by testing against different use cases and their respective benefit accounting. The trial is designed to be implemented such that lessons learnt and results from each stage can be incorporated into the method. Results can then be used to determine if the solution should be deployed in other distribution networks with similar constraints.

During the course of the project, an ICT control solution will be procured and developed to facilitate the services provision. It is proposed that the end-to-end communication, technical functionalities and monitoring equipment between DER, UK Power Networks and National Grid Electricity Transmission be tested prior to the trial commencing. Once testing has been successful and it is clear that the services can be provided, the trial stages will commence as detailed in Section 2.3 and Appendix 6.

Throughout the trial stages, the project will assess the learning outcomes quarterly and results will gain robustness and the confidence level of the results increase as the stages progress. This methodology of trial approach provides the project with a structured way to assess the effectiveness of the proposed solution and ensure impacts on customers are minimised.

The deployment of the solution and subsequent stages of the trial will enable a possible market route for National Grid Electricity Transmission to access distributed resources via UK Power Networks to create an efficient methodology for addressing system constraints.

2.1.5 The Solution

By creating a regional power market including DER in the South East, the SO will be able to tap into a previously unexploited resource. It will validate mechanisms by which multiple services and multiple constraints can be managed without conflicting with one another. Furthermore, it will create a whole system approach to addressing challenges on the transmission system by using resources on the distribution network to provide dynamic reactive support and create benefits for end consumers.

Combined with the benefits that can be derived from these DER, the project will also aim to use existing network assets and control functions to optimise the contribution to the transmission network.

The services provided by DER to National Grid Electricity Transmission via UK Power Networks coordination have been conservatively estimated from £1m in 2020 to £29m by 2050 savings for customers and will enable the distribution network operator to connect further 3720MW GW by 2050 of generation in the area.

2.2 Technical description of project

The TDI 2.0 is aiming to deliver in three key areas:

1. Provide access to dynamic reactive compensation capability from DER within distribution network. The service will be beneficial in terms of avoiding the reinforcement of the transmission network in the future.
2. Provide detailed arrangements for how the transmission and distribution will work together across the interface. Establish the market for accessing the reactive power and also flexibility for active power management.
3. Customer and stakeholder value through learning on coordinated operation of the transmission and distribution networks that is much more efficient than to operate them separately.

2.2.1 How will TDI 2.0 work?

The principles how TDI 2.0 will work are the following:

NG will instruct the voltage service through UKPN. UKPN will act as network operator managing the dispatch of the service in real time and act as an aggregator recruiting and establishing capability for reactive power service on behalf of NG and managing the dispatch of the DER in real time.

TDI 2.0 has three distinctive services:

1. Dynamic voltage service
2. Steady state voltage service
3. Balancing service using re-dispatching of MWs

The dynamic and state voltage services are Reactive Power Services and balancing services using re-dispatching of MWs is an Active Power Service.

Reactive Power Services

Dynamic voltage control provides stability after the significant network events by fast automatic changes of reactive power. Steady state voltage control helps the transmission network to manage periods of low demand when network voltages are high. Reactive power is expected to be procured on forward tender basis. UKPN will establish the effectiveness of each of the potential providers relative to their location, more deeply embedded suppliers in the distribution network will be less effective in providing voltage support to the transmission system.

Active Power Services

Active power services can be re-dispatch in real time by NG or UKPN such as that request will be within envelop of the DNO constraints on the network.

TDI 2.0 Service timeline

Table below shows project flow from planning through operation to settlement period. Key components during operation are metering and measuring needed to monitor service availability delivery and informing financial settlement.

	Planning				Operation				Settlement
	Estimate service need	Recruit DERs	Tender	Deploy ANM	Forecast volume	Take bids & share stack	Dispatch	Meter / measure	Verify, settle & report
Timing	18 months	18 months	12 months	6-18 months	24hrs-15mins	Within half-hr	Within half-hour	Within half-hour	1 day - 1 month
Main actor	NGET	UKPN	UKPN	UKPN	UKPN	NGET & UKPN	NGET & UKPN	NGET & UKPN	UKPN or 3rd party
Reactive	NGET estimates net requirement	Generate interest, agree compliance, publish de-rating factors	Run tender to secure availability, publish results	As part of connect-ion or post-connect-ion	Confirm DER ready, check D network	N/A	Dynamic: NA High: UKPN detect & dispatch	NGET measures at GSP, UKPN measures at DER	Payments made for service or non-avail-ability, monthly reports
Active	N/A	N/A	N/A	As part of connect-ion or post-connect-ion	Confirm DER ready, check D network, forecast volume	Combine bids and adjusted volumes, stack to NGET	D-constraint: UKPN dispatches T-constraint: NGET instructs UKPN to dispatch	NGET measures at GSP, UKPN measures at DER	Payments made for service or non-delivery, monthly reports

Financial flows in TDI 2.0

Figure 2.4 shows information, control and financial flows in TDI 2.0. UKPN will be the network gatekeeper, presenting the reactive and active power capabilities to NG.

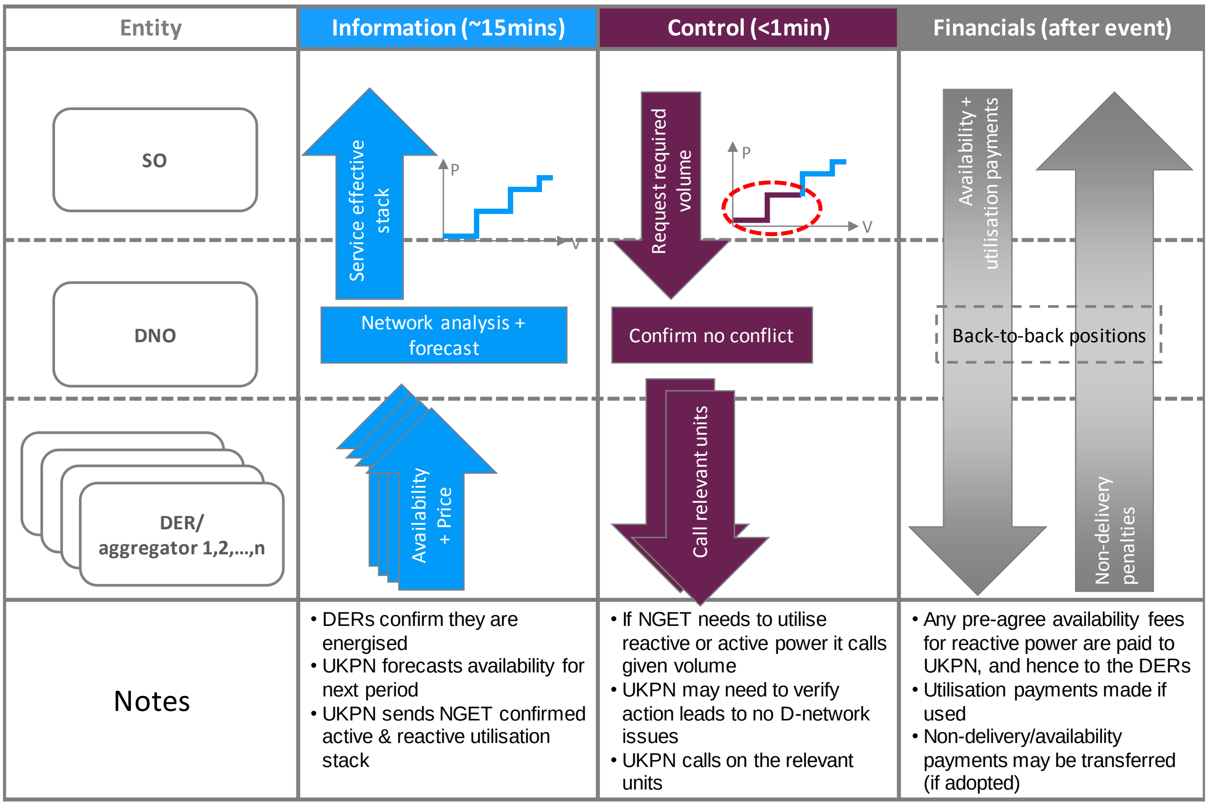


Figure 2.4: Information, control and financial flows

Figure 2.5 is an illustrative example of financial flows and benefits.

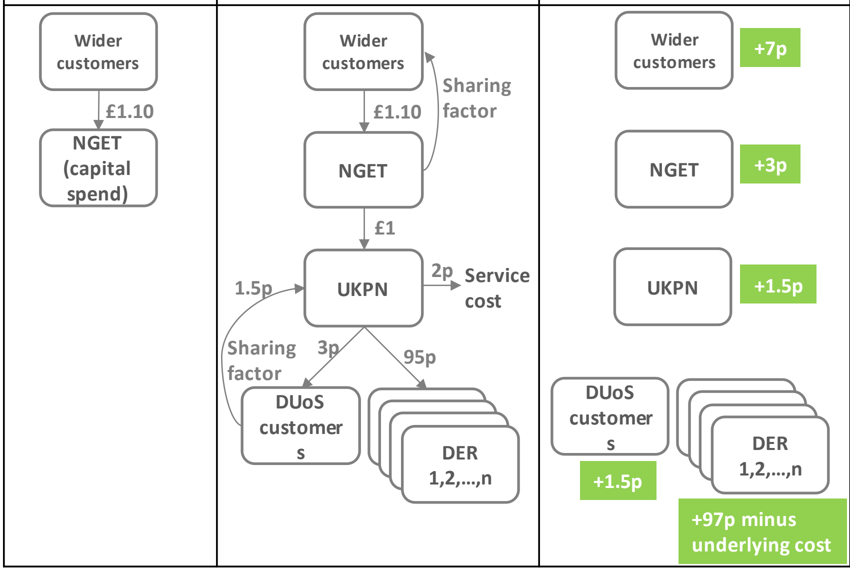
Base case (capex solution)	TDI 2.0 case	Net benefit	Notes/Assumptions
Capex solution for which the levelised cost for a given hour is £1.10	Opex solution for which the cost of availability payments for a given hour is £1.00 (95p DER cost and 2p DNO cost, 3p DNO incentive)	Savings accrue to TNUoS/BSUoS customers, with remaining spend benefiting SO, DNO, DERs and DUoS customers	Assumes TDI 2.0 is a cheaper solution than conventional capex, as demonstrated in the CBA
			• No distinction between TNUoS and BSUoS customers in this illustration but the impact on each will be reviewed as part of the trial • Assume NGET receives share of benefit from reducing TNUoS/BSUoS expenditure • Assume UKPN includes a service charge (e.g. for ANM system installation and operation) and mark-up • Assume UKPN shares new net revenue stream with DUoS customers • DER net benefit will depend on investment required to deliver service and the competitiveness of the market

Figure 2.5: Illustrative financial flows and benefits

Governance Process

The governance arrangements for TDI2.0 will be split into two parts related to (i) product development and (ii) the trial itself. Both would be overseen by an advisory panel which would consist of an independent chair, Ofgem representation and other key stakeholders. The full Terms of Reference would be developed as the panel is established; however, the panel would take an advisory capacity and would not be part of the approval process. The relevant licencing frameworks, Industry codes, legal and procurement requirements will be sufficient approval. This is an environment in which National Grid and UKPN have significant experience.

Product Development

The product design and development will be a transparent, engagement led process. A working group would be established to ensure the product delivers for all stakeholders.

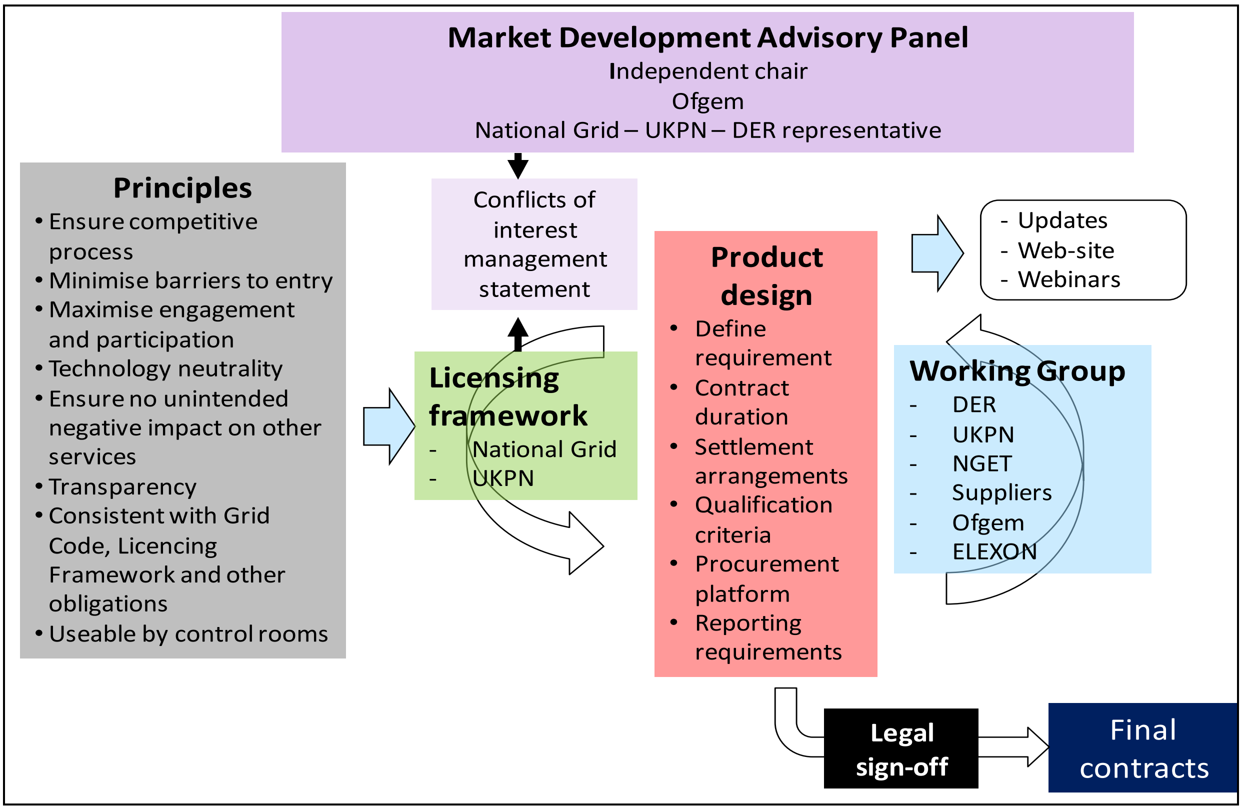


Figure 2.6: Governance arrangement – Product Development

Product Trial

The product trial will establish the contract structures, the procurement process to recruit the providers, testing and instruction. Key to the success is establishing measurement and settlement processes and producing transparent market information.

The output of the trial would be to undertake a review of all elements to inform a future strategy for this service. The aspiration would be to use the trail to give the learning required to establish a functioning and enduring GB market for this type of service.

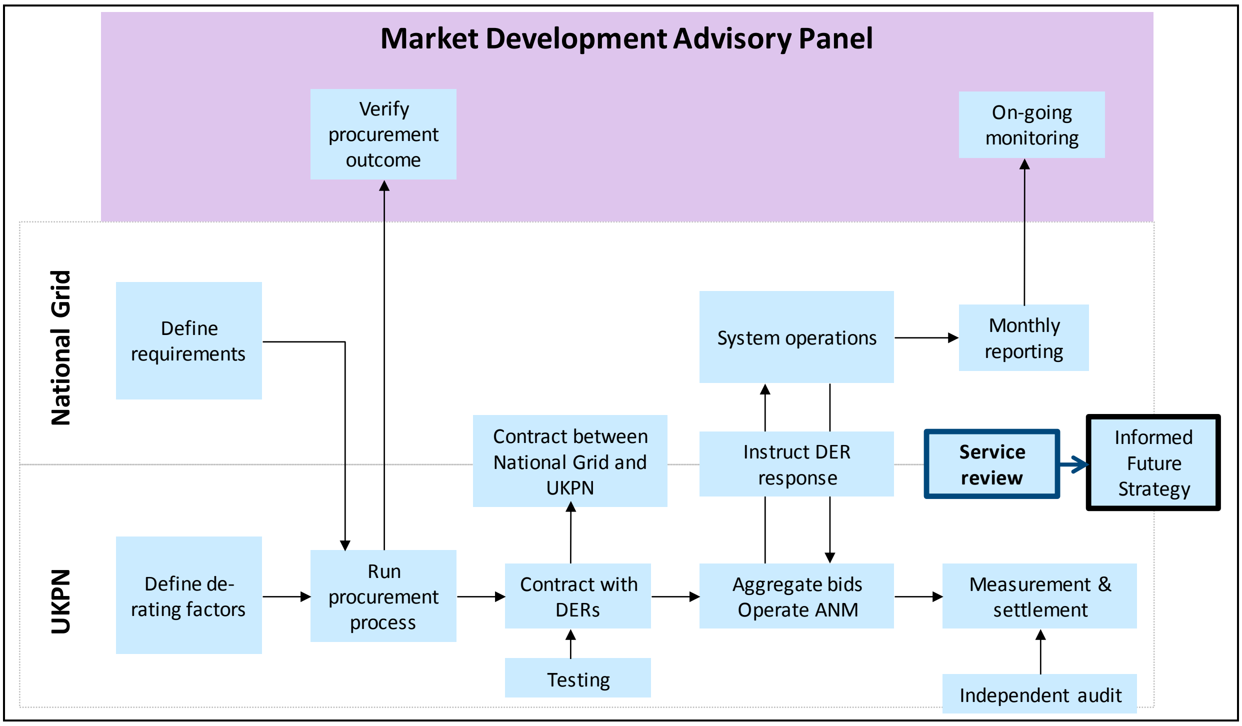


Figure 2.7: Governance arrangement – Product Trial

Market Development Advisory Panel Terms of Reference (TOR)
An advisory panel would be established at the start of the project. The full Terms of Reference (TOR) of the Panel would be developed as the panel is established; however, as this is an environment in which National Grid and UKPN have significant experience we have been able to outline a possible TOR framework:

- Purpose statement of the panel would be defined, however it is envisaged that the panel would take an advisory capacity and would not be part of the approval process. Any product and trial would be developed within the relevant licencing frameworks, Industry codes, legal and procurement requirements.
- Composition of the panel: The Panel will be made up of individuals representing the diversity of customers and stakeholders and will consist of:
    - Panel Chair, who shall be independent of any National Grid company.
    - Up to 10 independent stakeholder representatives, including National Grid, UKPN and Ofgem.
    - Panel Secretary.
- The role of Panel members would be defined; examples from other advisory panels included below:
    - Provide a different perspective and way of thinking to an area of focus.
    - Attend Panel meetings prepared to participate and be equipped with appropriate feedback from their part of the industry or area of expertise.
    - To be the voice of their customers and stakeholders by utilising their networks and relationships.
    - Provide their inputs and feedback based on their own personal experiences.
    - Help to develop problem statements, identify issues, causes possible solutions.
- Meeting frequency of the panel would be defined.
- Remuneration; It may be required to remunerated the panel Chair; this is consistent with other industry advisory panels.

- Confidentiality and conflict of interest - Panel members may be required to sign an agreement containing undertakings on confidentiality and conflicts of interest.

2.2.2 What will be the benefits?

When completed, the TDI 2.0 project will enable the System Operator to access dynamic and flexible resources on the distribution network via the creation of a market consisting of SO, DNO and DER. The project will additionally enhance the coordination framework in the planning processes of all participating organisations. The proposed new arrangement has the following benefits:

- Resulting in generation capacity released in the system to allow new DER connections in the DNO network quicker and at a lower cost
- creating new sources of income for participating DER and accelerating their rollout to enhance market competition to potentially drive reductions service provision costs. The CBA focused on the provision of active and reactive services from DER
- Recognising today's solutions, this new innovation offers operational solutions that are quicker to implement (no build time) and more flexible

The propose structure is one possible ways that industry models can work to address constraints in the network. The project does not provide a final stage of the model due to the fact that business models will evolve in the future. It provides opportunity to deliver a platform to practical exploration of how some of these arrangements might work.

Finally, the project has significant GB wide rollout potential. There are 59 National Grid Electricity Transmission sites identified that the method would be applicable to, and can deliver £412m of savings by 2050 across the GB.

2.3 Description of design of trial

The trial will seek to demonstrate the methods and their underlying hypotheses in a way that creates statistically significant learning outcomes. It will do so by developing a selection methodology for participating DER and carrying out staged demonstrations of the solution. The trial will ensure that the necessary processes are in place in both SO and DNO to achieve continued benefits in the long term. More information about the hypothesis associated with the methods can be found in Appendix 6 of this document.

An initial functional testing phase will be developed during 2018 to ensure that all technical aspects of the solution are working. During this phase, the ICT control solution and all the required communication equipment will be tested and cleared for operation. Afterwards, the trial will be divided in stages in which the number of participating DER will be increased. In order to determine which DER will be included in each stage, selection criteria have been developed and they will be applied prior to the beginning of each stage. Selected DER for each subsequent stage will be prepared to provide the responses with the necessary communication equipment ready prior to the start of each stage. Once they are ready, each stage will execute use cases relevant to each aspect of the method.

2.3.1 DER selection criteria

TDI 2.0 seeks to include as many market participants as possible to ensure that an optimum level of available services is achieved. However, for the purpose of the trial, it is necessary to create a selection criterion that will structure the results so that they can be extrapolated into a wider context. The criteria includes: the location of the DER, their technological capabilities to be able to provide the services and if they are connected in the system at the time of the trial. A sensitivity factor which incorporates all the previous criteria will be calculated to obtain their overall theoretical service effectiveness.

To determine the sensitivity factor (SF) calculation methodology, a modelling assessment was commissioned in preparation for this project to see the maximum theoretical reactive response from a DER connected in the UK Power Networks system. The SF was calculated to measure the change in voltage seen at each GSP due to reactive power injection from each DER. The SF was designed such that it is independent of the size of the DER, but shows the effectiveness of its location and technology.

This SF will be structured into a ranking system which relates the factor to the level of service effectiveness. The trial will focus initially on the most effective DER and will increase the number of participant's, stage by stage. Any new connected DER wishing to participate in the trial will be included as appropriate in each stage. A high level view of the trial methodology is presented in the following table.

TDI 2.0 TRIAL					
YEAR	2018	2019			
	Functional Testing	Q1	Q2	Q3	Q4
Stages		Stage 1	Stage 2	Stage 3	Stage 4
Participating DER (based on SF)		Includes new participants at each stage starting from the most effective ones in stage 1 onwards.			
Use Cases (as applicable)		1 to 5			
Learning Outcomes		Initial results → Robust results			

The proposed trial methodology includes multiple benefits such as: creating measurable learning outcomes in each trial stage to increase the result robustness, provides multiple opportunities to revise and improve the proposed methods. Throughout the stages, the learning outcomes will be monitored closely to ensure that there is sufficient evidence that the next stage can proceed and more participants are included.

2.3.2 Use cases

The use cases that will be used during the trial have taken into account the methods that the solution is looking to demonstrate and each of their learning outcomes. More information regarding the learning outcomes including measurement and success rates is presented in Appendix 6.

Use Case	Description
1. Technical delivery of services	Focuses on the top to bottom response of the reactive and active power services procured by National Grid Electricity Transmission and delivered by the DER through UK Power Networks.
2. Enhanced Methods to maximise response	Explores a novel approach to automatic voltage control (AVC) and voltage target changes at Grid (132kV to 33kV) and GSP transformer to maximise the response that DER can deliver.
3. Commercial Framework Validation	Will be used to engage with potential service providers and provide an insight into the value of the service to the SO, the cost of delivery to DER, and the length of contracts required for service contracts.
4. Market Effectiveness	Determines if the market is attractive enough for new participants and different technologies.
5. Co-Ordination of Services	Creates a framework of roles, process and proposed business changes to integrate the solution into today's model. Addresses interactivity with other commercial solutions and operational services options available to use by National Grid Electricity Transmission or DNO.

2.4 Changes since Initial Screening Process (ISP)

The TDI 2.0 Project is now expected to run from January 2017 until December 2019. The names for the 4 phases of the project are: Design, Build, Test and Trials. The first three phases (Design, Build & Test) representing around 70% of the total costs of the project. The total project budget has been revisited to £9.56m (ISP budget £11m) reflecting the better understanding of the scope and detail budgeting.

2.5 References

[1] Mayor of London, "Delivering London's Energy Future," London, 2011.

[2] National Grid, "Electricity Ten Year Statement," Warwick, 2015.

Section 3 Project Business Case

3.1 Executive summary for the business case

This project is proposing to use distributed energy resources (DER) for dynamic reactive response and active power re-dispatch to solve transmission and distribution constraints. The project will trial the effectiveness of the dynamic reactive response from DER on the transmission network. In parallel with dynamic reactive response, an active power service will be also tested to solve distribution constraints and offering flexibility as a service to the System Operator (SO). The commercial arrangements for the project will test the use of back to back contracts through the DNO for an active and reactive power services route. This arrangement also tests the existing contract structures between the SO and power generators.

The project could bring £29m of financial benefits by 2050 to end consumers, while providing more network capacity in the most economic and efficient way achieving reduction in carbon emission on the network. The cost savings accumulated to 2050, if rolled out across the 59 sites in Great Britain, would amount to £412m.

3.2 The Project Definition

Why we are doing TDI 2.0: The issue is that existing reactive power resources are not sufficient enough to allow more megawatt (MW) of DER generation to be connected into the distribution network. This project will accelerate the development of low carbon energy sector and will contribute to current government strategy for reducing the greenhouse emissions by releasing network capacity.

What are we doing in the innovative project TDI 2.0: This project will be developing and trialling an innovative control platform to predict dispatch and maximise dynamic reactive power response from distributed energy resources to support the transmission system. The control platform will also help the re-dispatch of active power between the distributed energy resources and potentially offer even greater flexibility to the SO to solve transmission constraints.

How are we going to do it in TDI 2.0: This project is developing a control interface between the SO and Distribution Network Owners which will use reactive and active power from DER. The project cost benefit analysis has focused on the reactive power from DER benefits and in order to quantify the benefits we will use the following methods:

Method 1 - Dynamic Voltage control from Distributed Energy Resources with reactive compensation in transmission system

Method 2 - Dynamic Voltage control from Distributed Energy Resources with reactive compensation in transmission and distribution system

For Method 2, we have modelled deployment of reactive power compensation using traditional solutions in both the transmission network and distribution network.

3.3 Background Information

The South East part of transmission network in Kent and Sussex has always presented operational challenges. Being the shortest distance to mainland Europe, this area is favoured for connection of HVDC interconnectors for trading power internationally. The climate of the area is also favourable for solar PV panels and small scale wind generation.

The benefit of TDI 2.0 would come in the form of increased DER deployment, which would is dominated by renewable generation thereby bringing carbon reduction benefits. It is also important to know that transmission lines will have voltage and thermal stability limits. Ideally, these two limits are very close or equal. It is the responsibility of the System Operator to keep the network within planning limits. In the South East part transmission lines, which have four grid supply points on their way, there is a difference between voltage and thermal limit of 530MW. Voltage limit is a limiting factor for new DER to be connected in the South East part of the network.

3.4 Cost-Benefit Analysis – Today's Model Assumptions

The costs of managing the constraints on the transmission network are primarily driven by the rate of deployment of DER. This rate has been forecasted by UK Power Networks, which is summarised in Figure 3.1, and culminates in an expected 3,720MW of new DER connections by 2050.

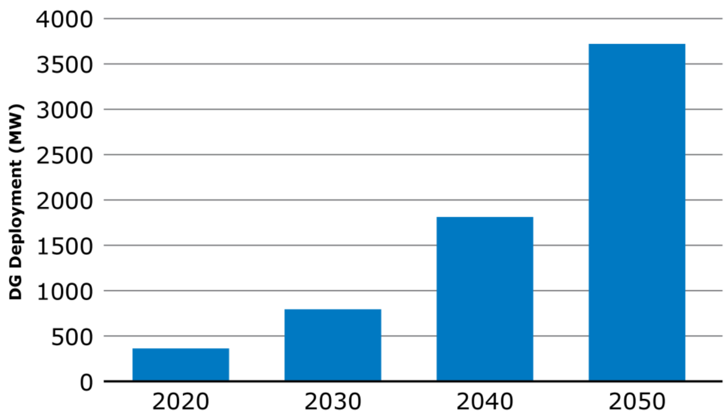


Figure 3.1 Assumed DG deployment profile

In order to mitigate the constraints associated with this additional DER, National Grid Electricity Transmission would need to deploy increasing levels of static and dynamic reactive compensation units. Based on power system analysis and system knowledge have assumed the following:

- For every 1 GW of transmission capacity required, 900 MVAr is needed at transmission level
- The gap between the thermal and voltage stability limit is estimated to be:
  - Currently: 530 MW
  - 2024 (After Dungeness is decommissioned): 1610 MW
  - 2040 (After Transmission circuit upgrades): 3210 MW
- New reactive compensation units are installed in equal ratios (balancing cost with capability)
- Reactive compensation costs are estimated (based on Electricity Ten Year Statement average)
- Weighted Average Cost of Capital (WACC):4.25%
- Annuity duration (years): 20
- the cost of active power curtailment that will be required alongside the reactive power compensation to keep the network within limits
- Duration of post-fault voltage control:11.69 hours

Under these assumptions, the expected capital expenditure (capex) on new reactive compensation units required to incorporate additional DER is shown in Figure 3.2.

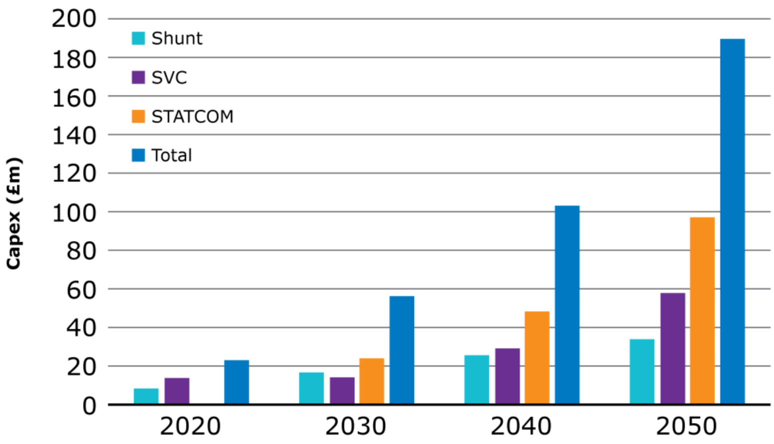


Figure 3.2 Capex profile under BaU scenario

The CBA model focusses on understanding the potential benefits of the DER reactive power compensation to the transmission network. Our model provides a conservative but robust view. The model does not therefore include:

- the cost of active power curtailment that will be required alongside the reactive power compensation to keep the network within limits has not been included
- the potential requirement for reinforcement of the south coast network with a new line running from the south coast to London has not been included

3.5 Cost-Benefit Analysis – Innovation Model Assumptions

The analysis is based on the assumption that existing DER connected at 11kV and above (in total 1,250MW) can be connected under the TDI 2.0 system and provide 400 MVAr of reactive compensation, and that all new DER are connected under the TDI 2.0 scheme. We have also used robustly conservative assumptions that we assume that each DER only provides the statutory minimum capability (0.95 lead/lag power factor).

Initial network analysis carried out as part of the bid preparation suggests the sensitivity, of existing DER to transmission network constraints ranges from 40% to 83%. For the purpose of this CBA, we have assumed an average sensitivity of 67% assuming that the TDI 2.0 project will encourage new DER connections in areas where they are more technically capable of delivering the services.

Applying the same methodology used for today's model scenario, we calculate the capex spend for reactive power compensation but accounting for the offsetting effect of the DER services. As a result, the transmission capex spend profile is reduced as shown in Figure 3.3. The dynamic voltage control service provided by DER is comparable to the service provided by dynamic reactive units ((SVC, STATCOM) and therefore it is assumed that under the TDI 2.0 scenarios further dynamic unit installation is not required.

Furthermore, the capex expenditure on static reactive units (Shunt reactors) is lower due to the increased MW transmission capacity provided by newly connecting DGs. Figure 3.3 therefore shows that the expected total capex on reactive compensation units is significantly reduced under the TDI 2.0 scenarios.

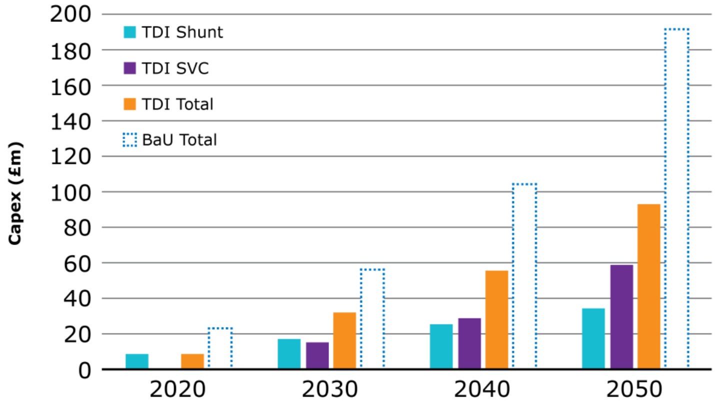


Figure 3.3 Capex profile under TDI scenarios

The TDI 2.0 scenario involves the use of DER reactive and active power services, which will involve National Grid Electricity Transmission incurring operational costs that were not present in the BaU scenario. We have assumed that reactive services are procured at a fee consistent with the Obligatory Reactive Power service (£3/MVArh), and that active power reduction reflects the opportunity cost of curtailed DG (on average £100/MWh reflecting wholesale price and renewable subsidy).

In the calculation of the TDI 2.0 operating costs, we make the conservative assumption that in order for the DG units to provide the DVC service (at a power factor of 0.95 lead/lag) that they must curtail their active power output by 5%. In practice this may be true for some existing DGs such as solar PV, which under their connection agreement must operate at unity power factor, which do not have the capability of supplying reactive power services at full rated active power output. But it is expected that DGs connecting post trial commencement will be required to operate between a power factor of 0.95 lead/lag at full rated active power output. The model will look at the possibility of incentivising the DER connections. One of the learning aspects of the trial will be to understand the impact of incentives in relation to technical capabilities.

Results

The Cost-Benefit Analysis performed for this project is based on the Spackman approach [1] which presents the financial benefits of each of the methods being trialled in the project at four points in time (2020, 2030, 2040 and 2050) on a cumulative basis. After combining the capex and opex for all scenarios, Figure 3.4 shows that the TDI 2.0 scenarios have a clear net benefit over the BaU scenario with Method 1 and Method 2 culminating in net benefits of £25.7m and £29.0m respectively by 2050.

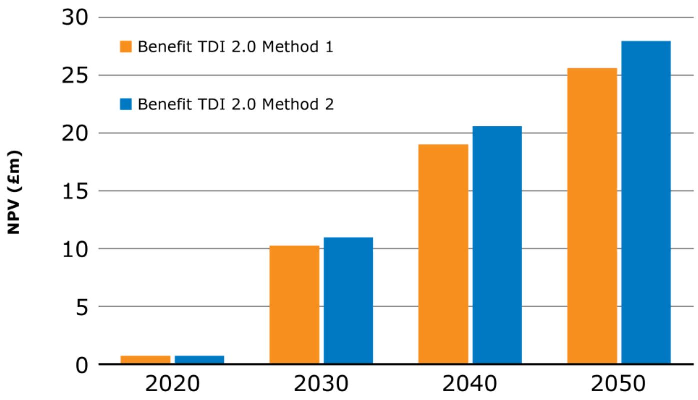


Figure 3.4 Benefit of TDI scenarios compared to BaU Scenario

Because of the way in which the TDI 2.0 scenario was defined, there was no difference in the level of DER deployed, so there would have been no substantial carbon impact. However, in reality we know that the connection of DER is currently being held up because of the transmission constraints. It is reasonable to expect even if efforts were made on the transmission network to alleviate these constraints, delays and barriers to future DER connection would be expected.

Traditional methods and the trial of TDI 2.0 would result in no difference to carbon reductions; however, there would be significant cost savings by using TDI 2.0 as shown in Figure 3.5.

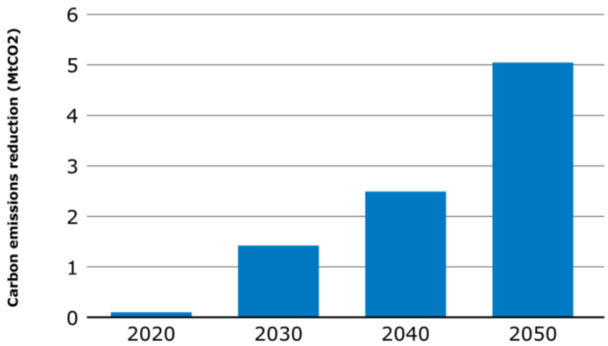


Figure 3.5 Carbon reduction associated with projected DG deployment vs average grid carbon intensity

At a rate of 23.38 £/tonne, this would have a value to society of £57.7m in 2050. However, this should not be seen as being in addition to the financial benefit already estimated above, since this is based on a different set of assumptions.

The overall benefits presented are based on a conservative view, there are other areas that have not been analysed but have an indirect impact including:

- Distributed Generation MVAr capability will provide an offset of dynamic reactive compensation units to achieve greater savings over a combination of static and dynamic units
- Increased access to storage resources
- New opportunities for demand side response
- Improved thermal limits by managing the DER and therefore provide further value without the need for transmission reinforcement
- Faster deployment for new connections. Capex solutions for reactive compensation can have significant lead times.
- Recognition of the technical limits of the reactive compensation

3.6 Limitations

The proposed innovative approach of voltage dynamic control with DER will support and help improve the voltage stability limits on the transmission network. The TDI 2.0 innovative approach to the network thermal limits cannot be increased, they can only be managed within existing limits (using MW re-dispatch of the transmission and distribution connected units). The limits of the existing innovative approach are when the method of dynamic reactive response and active power from DER achieves voltage limits equal to thermal limits on the network. To increase the thermal limit, the network reinforcement or lines re-conducting will be required.

3.7 References

[1] Discounting for CBAs involving private investment, but public benefit, 25 July 2012, published by the Joint Regulators Group (JRG)

Section 4 Benefits, Timeliness and Partners

(a) Accelerates the development of a low carbon energy sector and/or delivers environmental benefits whilst having the potential to deliver net financial benefits to future and/or existing Customers

Facilitate Low Carbon Generation: The South East of England is an ideal location for renewable energy deployment due to high solar irradiance and favourable wind conditions. This has attracted and will continue to attract a large volume of renewables projects that contribute to the Carbon Plan's low carbon generation objective. The TDI 2.0 method will alleviate the voltage constraints which are currently preventing new renewable generation from connecting in the area. This will facilitate a greater number of renewables projects in the area. In addition the innovative TDI 2.0 approach will displace the requirement to carry out lengthy network reinforcements, which should then increase the rate of distributed generation connections. Figure 4.1 shows the volume of capacity deployment facilitated through the TDI 2.0 method, culminating in the connection of 3.72 GW of distributed generation by 2050.

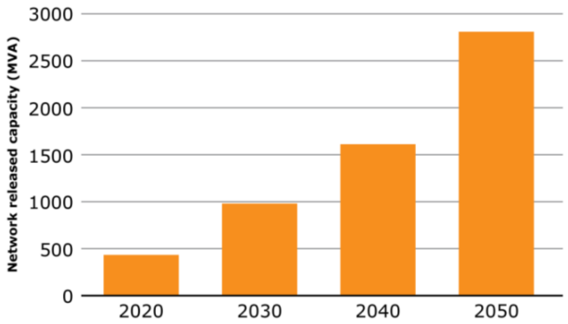


Figure 4.1 Network Capacity Enabled (MVA) for assumed DG scenario

The deployment of this volume of distributed generation, assuming it consists of solely renewable sources, results in the associated reduction in CO_2 emissions shown in Figure 4.2. It is estimated that by 2050 a total of 5 $MtCO_2$ emissions will have been avoided.

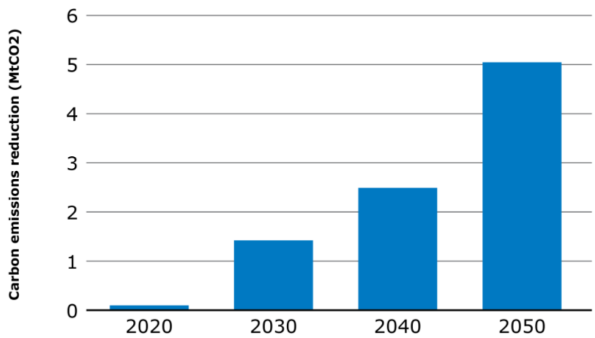


Figure 4.2 Reduction in Carbon Emissions ($MtCO_2$) for assumed DG scenario

Please note that under the CBA assumptions, today's model and the innovative TDI 2.0 approach will release the same amount of network capacity and provide the same reduction in CO_2 emission but the TDI 2.0 approach will cost significantly less. In reality it is expected that the network reinforcements required under today's model would significantly delay the connection of distributed generation.

Deliver net financial benefits to Customers: The TDI 2.0 approach maximises the volume of generation that can connect to the network while minimising the cost of network maintenance and reinforcement. This reduction in cost is ultimately passed on to customers through reductions in BSUoS charges and cheaper new connections to the distribution network. The financial benefits of the TDI 2.0 method in comparison with today's model in terms of the avoided network management spend by NGET are shown in Figure 4.3. It is forecasted that up to £29m of savings could be made by 2050 under the TDI 2.0 approach. In addition, the TDI 2.0 approach creates new potential revenue streams for DERs through the establishment of the reactive power service and active power management markets.

Rollout to the GB Network: The TDI 2.0 project will trial and demonstrate the value of DERs providing reactive and active power services for the management of network constraints. Once proven successful, this method will conservatively provide savings of over £29m by 2050 in the South East. We are expecting that similar trials can be replicated across the GB transmission system, in particular the greater urban areas of London and the Midlands where National Grid have seen the sharpest decline in reactive power demand. The TDI 2.0 approach is a unique approach which has not been trialled by any other network licensee.

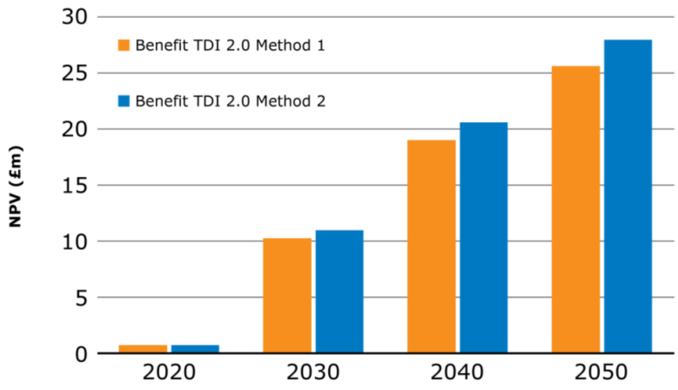


Figure 4.3 TDI Benefits in comparison with today's model (£m)

(b) Provides value for money to gas/electricity distribution/transmission Customers

As previously stated, the TDI 2.0 project will deliver an estimated financial benefit of £29m by 2050 in the South East network which will ultimately be passed on network customers. Further details on the benefit of the TDI 2.0 approach can be found in the Cost Benefit Analysis in Appendix 10. We believe the project also provides value for money by the way it is procured and contributes to the wider network community.

Competitive procurement processes: To ensure that the project is delivered at a competitive cost, during the course of the preparation of the bid submission, we have issued a request for qualifications, and followed this up with meetings with possible vendors to discuss the proposal. For each of the initial supplier responses received, these were evaluated and down-selected to our preferred vendors based on experience, value for money and methodology, with a particular emphasis on cost effectiveness to ensure that budgetary restrictions are met. During the pre-contract award phase, a full request for proposal (RFP) process will take place to determine our preferred vendor / technical partner.

Project Funding and Costs

Figure 4.4 shows the cost of delivering TDI 2.0 is £9.56m with £1.5m funded by National Grid and UK Power Networks. Figure 4.4 also shows the breakdown of costs across the TDI 2.0 Project Phases.

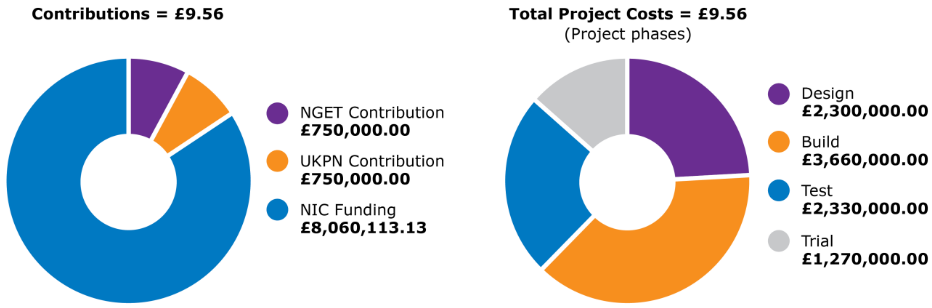


Figure 4.4 TDI 2.0 Funding Proposal and High Level Cost Overview

Figure 4.5 summarises the resources and rates used for the four project phases.

Partner Resources and Rates			2017				2018				2019				Total Man Days	Total Costs
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
		Days per Quarter	65	65	65	65	65	65	65	65	65	65	65	65		
Project Description	**Organisation**	**Rate**	**Design**				**Build**		**Test**		**Trial**					
Project Resource Costs	National Grid	£ 500.00	13	71.5	111	111	84.5	52	58.5	49	19.5	19.5	19.5	19.5	627.5	£ 313,750
	Joint Role - Internal	£ 450.00	65	90	108	100	130	130	163	163	143	143	143	143	1520	£ 684,000
	UKPN	£ 400.00	105	140	210	241	190	156	124	104	26	26	26	26	1373	£ 549,200
	Contractor	£ 600.00	97.5	195	195	195	260	293	228	228	117	117	117	104	2145	£ 1,287,000
Technical Partner Costs	Technical Partner	£ 550.00	130	195	195	195	390	425	425	385	65	0	0	0	2405	£ 1,322,750
Consultants (ensuring key deliverables and eaerly progress whilst resourcing is underway)	Consultants	£ 1,450.00	32.5	65	65	32.5	32.5	32.5	32.5	32.5	33				358	£ 519,100
Academia Costs	Academia	£ 512.82	64	65	65	65	65	65	65	65	65	65	65	65	779	£ 399,487
Data Modelling Costs	Data Modelling Costs	£ 900.00		65			65								130	£ 117,000
Power Systems Costs	Power Systems Costs	£ 700.00	65	65											130	£ 91,000
Total																£ 5,283,275

Figure 4.5 Resources and Rates

National Grid and UK Power Networks will aim to use internal resources via existing and new appointments. However, to ensure success of the project, the budget has allowed for contractor rates for specialist positions such as lead design authority and testing coordinator that might not be readily available in the two organisations or difficult to recruit. In addition, consultancy spend has been budgeted to ensure that key project roles can be covered from day 1 while the resourcing and mobilising phase is progressing or support key deliverables. This approach reflects lessons learnt from the delivery of previous Low Carbon Networks Fund projects.

Design Phase – This phase delivers both the Technical and Commercial Designs and ensures the ensuing c.£7.25m (Build, Test and Trial) spend is effective and meets project objectives.

Due to the nature of the project and the need for an innovative commercial framework c.£275k will be spent during this phase (Project Resource Costs) to perform this work, largely sourced internally from National Grid and UK Power Networks.

To ensure the quality of this Commercial design and alignment with the Technical Design, Project Resource Costs include a Design Authority (c.£101k during Design and c.£218k over the life of the Project).

Also during the Design Phase c.£91k is spent with consultants to deliver complex dynamic power system simulations, a specialist activity. Selection of this consultancy is underway in accordance with the competitive procurement process.

Build Phase - Following successful completion of the Design Phase, the Build Phase sees investment in both IT Assets, such as servers (c.£400k) and interfaces (c.£500k), and Field Assets necessary to monitor the distribution network and control the DER.

The Build Phase will also deliver the configured IT product ready for testing and will see the Commercial Workstream operate a Commercial Tendering process and commence signing customers onto the Trial (c.165k – Project Resource Costs).

Test Phase - As the project shifts from the Build Phase to the Test Phase the focus will be on comprehensive testing of the solution which will include end to end (DER /Aggregators/ Customer Involvement) and at which point the Project will be expecting to make payments to IT Partners with regards to License Costs (c.500k) as the product prepares to be used in Trials.

At this stage of the project we may also be required to access the Commercial Contingency in relation to under recruitment for the trial, see table below (1. Mitigating under-recruitment risk) and Project Risks (Appendix 5)

Commercial Contingency	Description	Contingency Calculation	Contingency Budget
1. Mitigating under-recruitment risk	This trial is intended to test both the technical and the commercial aspects of the proposed scheme. However, it will only be possible to test the technical aspects if sufficient numbers of DERs can be recruited. A contingency fund is required to bolster recruitment if needed.	£330k for enhancing DG reactive capability, £188k to cover battery costs	£ 518,000.00
2. Limiting stakeholder exposure to commercial risk	It is assumed that trial funds will be used to cover payments made by NGET to DERs via UKPN (estimated at £150k). Contingency funds will also be needed to cover volume and price risk, which may arise in a number of ways: • DER non-delivery (e.g. technical fault) • Sensitivity risk (effect of DER at GSP is under-estimated and hence over-priced) • Comms failure (resulting in available DERs being unable to deliver services through UKPN systems)	£40k to cover the need to procure reactive from other sources, whilst still potentially paying DERs availability fees	£ 40,000.00
3. Service Payment Funding	National Grid will not be paying for services during the trial through BSUoS	We have assumed in our CBA that by 2020 the cost of DER service procurement will be £314,000, being paid to an expected 387MW volume of distributed generation. During the trial itself we anticipate the participating volume to be lower than this, with the upper end of expected volume of distributed generation being 50% of the 2020 volume. This translates to service payments of £157,000 during the trial.	£ 157,000.00

Figure 4.6 TDI 2.0 Commercial Contingency

Trials - Assuming successful completion of the testing and a positive outcome from the Go / No-Go meetings the project will move into the Trial Phase, where we will be expecting to have available the Commercial Contingency as per Figure 4.6.

This part of the project will also see a significant reduction in the number of IT Partners, Consultants etc. as the business starts to operate the trial and look at how to shift operations into BAU.

The duration of the activities and effort required has been based on similar IT project deployments that the participating companies have undertaken and their experience and expertise. It has received input from the IT suppliers and project plan through their formal submissions and follow up Q&As to ensure deliverability within the allocated budget and time.

Finally, it has been benchmarked against successful budgets and plans from previous Low Carbon Networks Fund project, incorporating lessons learnt as appropriate.

The costs have been calculated using UK Power Networks, National Grid standard day rates, average contractor and consultancy rates and benchmarking of costs from the first stage of the procurement exercise for the TDI control system.

(d) Is innovative (i.e. not business as usual) and has an unproven business case where the innovation risk warrants a limited Development or Demonstration Project to demonstrate its effectiveness

TDI 2.0 will demonstrate a number of new innovative concepts:

1. Technical feasibility of using DERs dynamic reactive response for resolving complex transmission constraints

Constraints in the transmission system are complex as they not only can occur in different timescales, but their consequences to system operation are significant. The project will prove the reactive power practical effectiveness of resolving those transmission constraints using additional services from DERs embedded in the distribution networks. The methods of the project, and subsequent trial and use cases, have been configured such that they can quantify the effectiveness of the proposed services under different response timeframes (both pre-fault and post-fault) and various operational scenarios.

2. Introduces DERs to reactive power market

The SO manages transmission voltages by instructing Balancing Mechanism Units (BMUs) thought Ancillary services agreement under The Connection and Use of System Code (CUSC).

The TDI 2.0 will use DERs to provide voltage and reactive compensation, within distribution network and maximise potential contribution to transmission system voltage control.

Thus, there is a previously un-tested opportunity to bring the technical capabilities of DERs to provide reactive power services to the SO.

Although the SO has the possibility to use DERs for energy balancing services, it does not use DERs to manage system constraints. DNO is already using existing DER to manage the existing distribution constraints, however there is opportunity some of the remain DER capacity and flexibility to be offered upstream to SO for managing transmission constraints.

Besides the technical objectives of TDI 2.0, the project seeks to create another route to market where the SO has access to flexibility services from DERs coordinated via the DNO. This required level of cooperation will bring together the SO, DNO, and DERs to develop an extended reactive power market that gives the SO access to additional resources to manage network constraints.

3. DNO as an additional route to market, enabling DER to provide network services to both distribution and transmission

The SO has an established set of market routes and market participants that is procuring services from. The project will introduce the DNO as another alternative route to market for procurement of services. The DNO will act as one of the routes to market and the technical coordination of an increasing active distribution network.

For transmission constraint management services this entails the DNO establishing the effectiveness of each DER in resolving transmission voltage and thermal constraints. This will be dependent on DER technological capabilities, location relative to the constraint, proximity to load, and DNO network topology and local restrictions. The ICT control solution procured for the project will be dynamic with forecasting, optimisation, and scheduling functionalities to deploy, or facilitate deployment of, DERs as a transmission network service while coordinating and respecting activity under ANM schemes for distribution network restrictions. The communications, control, and monitoring systems will also need to be enhanced from the current operations.

The use of DER within the DNO network could expose both the SO and DNO to new risks and rewards. The trial project will explore both of these themes in great detail.

4. Introduces market-based mechanisms for co-ordinated network management

The existing FDG schemes have successfully demonstrated they can allow more generation to connect to constrained areas of the distribution network. Its use of Last In-First Off (LIFO) principles of access offers a transparent arrangement for new developers, but still suffers as it lacks an optimised use of the network capacity and DER additional services.

In the current LIFO arrangement, the effectiveness and willingness of the DER to solve a particular network constraint is not taken into account when deciding the order of curtailment. Nor is the impact on the whole system, the overall energy balance and other network requirements such as voltage management.

This could lead to a situation where a DER located furthest from the constraint is being curtailed more often than a DER that is located closer to the constraint just because the latter has been connected in the system for longer. A market arrangement could apply the principle that the DER's willingness to be curtailed, as well as their effectiveness, is used to determine how to address network constraints. DER willingness will be indicated by bids and their respective cost. A higher curtailment cost would signal a particular DER does not want to be constrained, whereas a lower curtailment cost will indicate more willingness to be constrained. Another opportunity is that DER costs become visible to market players and to network operators which can be used to signal and inform either a market response or appropriate network reinforcement.

The transition towards market-based curtailment arrangements will require development of market rules and structures. The trial will enable the DNO and SO to develop these capabilities, not just to resolve distribution constraints, but also to facilitate network services from DER to the transmission network.

Both transmission and distribution systems in the South East are facing increased challenges due to large DG penetration. The aforementioned innovations encompassed in the TDI 2.0 project have been identified as a possible route to tackle constraints and allow more DER to be connected in the area. Although both SO and DNO will continue working to facilitate DER connections to be made between now and the development of the project, these measures will not be able to address all of the constraints in the network. TDI 2.0 is an innovation approach to evolve the business as usual measures and maximise the use of existing (and up to now untapped) resources in the system.

(e) Involvement of other partners and external funding

The key principle of this project is the partnership between National Grid and UK Power Networks, Transmission System Operator and Distribution Network Operator, in order to relieve transmission constraints using distribution-connected resources.

The process of selecting project partners at National Grid started with the identification of priority areas in 2014. Both the Transmission Owner and System Operator reviewed the areas of greatest potential to deliver cost savings to customers, or areas with significant risk of cost increases as a result of the changing nature of the electricity system, to determine priority themes for customer value. This review identified nine priority areas: managing assets, efficient build, service delivery, corporate responsibility, changes to electricity demand, operating with non-synchronous generation, operating with distributed generation, smart grids and managing new risks.

Information about these themes was published on the National Grid website and interested parties were invited to propose NIC and NIA projects. Six proposals were received from various innovation partners and these together with ideas from within National Grid were compared and assessed against the NIC criteria and National Grid's innovation strategy. This project was assessed to be timely, with clear potential benefits to customers and most directly relevant to the electricity network and operations of the system operator.

The project objectives also align with UK Power Network's strategy and, as the DNO in the south coast, will play a key role in the project.

UK Power Networks and National Grid publicised details of the proposed project in May 2016 to determine the level of interest from potential trial participants. Around 20 companies responded with expressions of interest including aggregators, renewable generators, storage developers, and a large demand customer. These companies have existing connected assets in the area or have projects in the pipeline that could provide the requested service.

All interested companies were contacted again in Jun/Jul 2016 and interviews were held where an update was provided and feedback regarding technical capabilities and commercial requirements was gathered to inform the project proposal and submission. The sessions were successful in engaging potential providers on the aims of the project and useful insights were captured. At time of writing, 12 companies of which 9 are aggregators, has confirmed, either verbally or written, support for the project objectives and interest in being a trial participant. Letters of support are given in Appendix 11.

Trial participant selection will take place after the submission as the technical specifications and commercial arrangements are finalised. Project partner(s) were also sought for the control systems solution that coordinates and integrates the data and instruction flows between National Grid, UK Power Networks, and distribution-connected resources. A Request for Information resulted in 8 companies responding. Follow-up meetings were held in order to evaluate the various solutions, capabilities, and costs of potential partners. The procurement process will continue from August to November, however due to the diversity and complexity of proposed solutions a partner will not be selected until after the submission deadline.

Academic involvement was another important consideration in the project whose expertise can maximise the project potential. This will be through application of robust academic methods, trial of novel ideas and techniques, and knowledge dissemination. In total 11 academics from 8 universities were contacted who has proven expertise and interest in the field. At time of writing 5 academics has responded to confirm support for the project objectives and interest in participating, with most also providing detailed research proposals. Academic involvement would benefit specific areas of study such as network modelling and control, trial design and validation, and economic and commercial designs. Confirmation of the academic partner will take place during the bid evaluation process and will be confirmed as part of the revised submission.

Robust contractual agreements will be put in place that ensures compliance with the NIC Governance. Both National Grid and UK Power Networks have experience of producing contracts under other innovation programmes.

Other industry stakeholders have also been informed of the project including Elexon and suppliers.

(f) Relevance and timing

The proposed TDI 2.0 project is both relevant and timely for three reasons:

1. Transmission constraints are already restricting the ability to accommodate additional DG in this network area
2. There is a broader need to explore options for the active DSO model, a key aspect of which concerns the interface between transmission and distribution system operation
3. A coherent approach to distribution and transmission constraint management should deliver the maximum benefit to developers and electricity consumers.

Releasing DG at lower cost

As explored throughout the document, NGET has calculated operational and planning limits based on their transmission constraints which dictate the amount of demand or generation that can be connected on the South East distribution network. Due to the rise in DG connections, these limits for generation are rapidly approaching. This means that without significant and costly capital expenditure UKPN might not be able to accommodate any further DG connections in that area, which would have a direct impact on the continuous deployment of low carbon technologies in England.

These constraints are already becoming binding, but as Section 3 explores, in order to accommodate the expected DG connection requests in this area, a conservative estimate of the cost associated with managing the transmission-level impact would reach £361m by 2050. By this year, TDI 2.0 is conservatively estimated to reduce these costs by between £25.7m and £29.0m. Assuming this scheme could be deployed more widely across GB it is estimated that the benefits would increase to between £379m and £412m. The benefits table in Appendix 1 give more detail behind these figures and the benefit values for the interim years.

The above estimates assume that DG deployment can be fully accommodated, albeit at a high constraint management cost. Because of this, TDI 2.0 does not release additional capacity. In practice we anticipate that the high cost, increased complexity and the time needed to deliver the required upgrades to accommodate this DG would result in lower levels of DG deployment, meaning that TDI 2.0 would bring a combination of financial and environmental benefits.

DSO model exploration

The project is an opportunity to test the interactions and mechanics of a more active DNO/SO interface. This proposed structure is one of the possible ways that industry models can work between SO and DNO to jointly address constraints in the network. The project does not provide a final stage of the model due to the fact that business models will evolve in the future. However, it provides the opportunity to deliver a platform for practical exploration of how some of the arrangements might work and their evolution in upcoming years. The methods explored during the project will also develop the key capabilities for the DNO to actively manage networks and evolve into a DSO role.

As TDI 2.0 focuses on consolidating and fine tuning the already existing coordination framework between SO and DNO and to embed the methods into the new business as usual, it is envisioned that future price control submissions for both companies will be impacted by the TDI 2.0 conclusions on roles and responsibilities. Once the learning outcomes are achieved, there could be changes in the investment strategy of both SO and DNO in the first instance as a wider use of TDI 2.0 solutions will be applied to transmission constraint management and hopefully be deployed in other areas of the system with similar constraints (and possibly deferring reinforcements).

Furthermore, the project will bring insights into the value of reactive power from flexible resources made available to the SO via DNO coordination. It can also be used to assess what is the most effective way to provide dynamic reactive response and how future strategies for voltage management will change. A possible outcome of this assessment will impact future business plans of the companies as it will analyse what is the most cost-effective way to improve voltage constraints, as it could be achieve via capital expenditure on the transmission network, on the distribution network or an optimum combination of both.

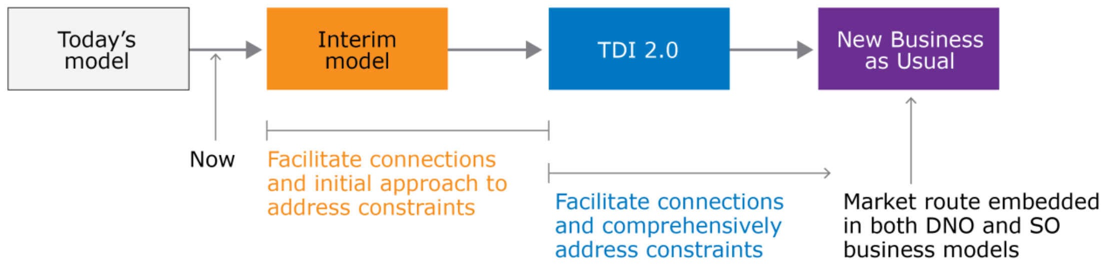


Figure 4.7 Constraint management evolution

TDI 2.0 will not preclude the exploration of alternative ways in which SO-DNO coordination could develop. For example, prior to the TDI 2.0 trial going live, an interim solution will be adopted. This interim model will be the first step to introduce flexible connections in the area and explore potential services and coordination between the NGET and UKPN and to allow more DG (in particular storage) to connect in the area to offer congestion management as well as other ancillary services such as frequency response. This interim approach will provide further connections in the area.

TDI 2.0 will continue to evolve those coordination efforts but complement the model with a toolbox for the SO to manage constraints upstream and an evolved ANM strategy for the DNO. Assuming the technical and commercial coordination is proven effective, and provided the benefits outweigh the additional costs, the approach can be embedded into the future business models of each market participant.

Section 5 Knowledge Dissemination

5.1 Learning generated

TDI 2.0 Project will generate extensive learning opportunities for National Grid, UK Power Networks, the wider Distributed Network Operator community, renewable generation developers, national and international standards bodies, academia, local authorities and other key bodies such as the Energy Networks Association, Department of Business Energy and Industrial Strategy, and Ofgem. In order to ensure that learning is effectively disseminated, a dedicated role within the Project Management Office, will be established for this purpose.

5.1.1 Learnings Generated Pre-Trial

Whilst the trials will generate a numerous learnings, there are a number of learnings to be capture pre-trial. These learnings have been broken down by project phases:

- A cumulative view from customers, Partner/s, UKPN and National Grid on how the full solution will work to support the TDI 2.0 trials. This will include how the commercial framework has been shaped, defined technical solutions to support activities, definition of involved party responsibilities, relevant business process and organisation changes where required
- An insight into the effectiveness of the proposed commercial framework, through the customer tendering process
- An understanding of existing and new customer readiness to operate within the TDI 2.0 trials environment, changes required to prepare customers and the effort required to ensure trial readiness. This will include but not limited to assessing system capabilities and changes required, field based hardware requirements, people and process changes etc.
- Performance of the TDI 2.0 technical solution in a controlled environment. Understanding this performance will be used as a baseline to assess performance of the solution during the trial and help to understand the impact of increased customers, environmental factors etc.

5.1.2 Learnings Generated During the Trial

The trial will generate a number of key learnings linked to drivers behind this project, these learnings will include:

- Clarity on whether the delivered TDI 2.0 technical solution is scalable and viable, these learnings will include:
- The ability of the solution to accurately estimate the response at Grid Supply Point level. (Dynamic and steady-state)
- Capacity of the DER to provide a combination of reactive power and active power services simultaneously
- If the solution response is in line with National Grid Electricity Transmission requirements
- Understand how different operational environments affect the DER service response
- Understanding of enhanced AVC controls to maximise service response at Grid and Grid Supply Point

It will also validate the commercial framework design, so:

- Understand how the commercial framework can evolve during and post this project
- How future markets can be designed such that it can benefit all parties and be attractive to new and existing participants
- Inform if other explored services can be deployed simultaneously and their effect on the effectiveness of the original TDI 2.0 service

- Understand which organizational/process/business changes are needed to align the services into today's model of the SO and DNO/DSO.

5.2 Learning dissemination

The Learning Dissemination role will focus on both internal and external learning and knowledge sharing activities, and will build on the knowledge that is shared with other relevant Low Carbon Network Fund, Network Innovation Competition / Network Innovation Allowance projects such as Flexible Plug & Play and Kent Active System Management.

A knowledge dissemination roadmap will be developed at the start of the project to produce a clear and effective plan and process for sharing learnings. The goal of this roadmap is to ensure accessibility to, and sharing of the project results and methods. The knowledge dissemination roadmap will ensure timely sharing of information based on a Successful Delivery Reward Criteria. The roadmap will also adopt a well-structured methodology in order to define:

5.2.1 Dissemination Objectives and Scope

The Knowledge Dissemination Lead will:

- Identify appropriate persons and organisations with interest in the project and its outcomes;
- Ensure that all knowledge gained throughout the project lifecycle is available to relevant interested parties; and use the most appropriate channels to share the gained knowledge.

Project TERRE

"The purpose of Project TERRE (Trans European Replacement Reserve Exchange) is to identify the optimal way to share Replacement Reserves between TSOs. The project seeks to establish and operate a platform for gathering Reserve offers from each local TSO balancing market and provide an optimal allocation to cover each TSO's balancing needs. Specifically the project seeks to assess the costs and benefits of such a cross-border balancing solution, identify potential barriers and required market design changes, and to understand the IT development requirements.

TDI 2.0 will develop an IT system and communication system, and an accompanying market framework to provide a both the TSO and DSO with access to Distributed Energy Resources (DERs). As such, the outcomes of each phase of the TDI 2.0 trial should provide valuable insight to Project TERRE. This will, to some extent, depend on the timing of Project TERRE roll-out, but it is indicated that implementation will not be before Q3 2018 and may be later. The initial SDRCs scoping out the market and technical architecture and engaging with potential participants should arrive in sufficient time to enable valuable knowledge sharing. It may also be possible for services procured under TDI 2.0 to be offered into the Project TERRE framework, although this will depend on the readiness of each programme and the compatibility of the services procured (e.g. the technical standards, short-term forecasting and tender structure)

The anticipated benefits of Project TERRE include enhancing the efficiency of balancing markets, promoting the exchange of balancing services whilst ensuring operational security, ensuring transparency, minimising barriers to entry, and facilitating the participation of Demand Side Response and renewable generation. These ambitions align with those of TDI 2.0. Whilst there will undoubtedly be differences in the way in which balancing services are shared TSO-TSO as opposed to TSO-DSO, it is strongly suspected that there will be numerous parallels between the two projects that will mean that the findings of TDI 2.0 will provide valuable insights."

5.2.1.1 Dissemination Products

This will include but not be limited to the following items:

Milestone / SDRC	Description	Product/s	Responsible
Stage Gates	Four key stage gates are built into the delivery of the trial to monitor progress and approve spend	Stage Gate Reports (Design, Build, Test, Trial)	Project (National Grid & UK Power Networks)
Industry Forums and Customer Engagement sessions	Regular industry forums will be setup to provide interested parties and opportunity to engage with the project. This will include providing customers the opportunity to input into the design of the commercial framework and technical solution	Industry Forum Update	Project (National Grid & UK Power Networks)
Project Mobilisation	As part of mobilisation website will be established and regularly updated with materials to provide interested parties the opportunity to review project learnings	Website All non-sensitive materials	Project (National Grid & UK Power Networks)
SDRC 9.1 Technical High Level Design	The high level design of the technical solution and high level business processes which will operate the solution	High level design specification Functional design document High level business processes	Project (National Grid & UK Power Networks)
SDRC 9.2 Stage Gate 1 – Commercial and Detailed Technical Design	The agreed detailed technical design (Partner/s, National Grid, UKPN and Customers) and Commercial Framework for the trial	Functional Specification Documents Finalised Commercial Framework Detailed Business Processes	Project (National Grid & UK Power Networks)

SDRC 9.3 Commercial Tendering Process Report and Finalised Trials Approach	Outline the learnings from the tendering rounds for the reactive and active power services, and advise based on this process and the trials approach which customers will be brought on when in the trial and forecasted effectiveness during the trial phases	Signed Commercial Contracts Trials Approach and Methodology	Project (National Grid & UK Power Networks)
SDRC 9.4 Stage Gate 3 – Customer Readiness Report and Performance of the Technical Solution in Controlled Environment	Update on the effort required to ready customers to take part in the trial (technical, business processes etc.) and the performance of the technical solution in a controlled environment and expected performances in the live environment	Test Report – End to End testing Business Change Implementation Report Customer Readiness Assessment Technical Solution – GO / NO-GO Criteria Results Customer and Business – GO / NO-GO Criteria Results	Project (National Grid & UK Power Networks)
SDRC 9.5 Cost Benefit Analysis	Analysis assessing the financial case for the trial to date and for extending the approach into the future	• Detailed assessment of the costs and benefits of TDI 2.0, to include: • analysis of the net benefit of extending the trial into the future (using Ofgem's CBA framework), replication study assessing the viability of, and case for, extending TDI 2.0 to other DNOs and for providing a wider set of services	Project (National Grid & UK Power Networks)

SDRC 9.6 Trials Report	The completion of the trials in line with customer agreements and review of the performance of the trial; the closure of the project (potentially moving into BAU) in line with customer agreements	• Trials Phase Report including adequacy of contracted volumes to meet requirement, availability/reliability of DERs and control system, accuracy of sensitivity and accuracy forecasting, evidence of competitive bidding, evidence of conflicts	Project (National Grid & UK Power Networks) Partner/s Aggregators and Customers
SDRC 9.7 DSO risk-reward framework for providing wider system services	DSO risk-reward framework for providing wider system services – a paper describing the incentive framework used for the project and recommendations for an enduring incentive framework for an active DSO	· Analysis of the costs, risks and revenues for the services included in the trial · Assessment of mechanism used within the trial and comparison against alternative incentive mechanisms · Assessment of the applicability of these incentive schemes to a DSO providing a broader set of system services and interaction with the wider SO incentives	Project (National Grid & UK Power Networks)

5.2.1.2 Dissemination Audience

The target audience for dissemination of activities is anticipated to include but not be limited to:

- National Grid staff
- UK Power Networks staff
- All GB Distributed Network Operators
- The Energy Networks Association (ENA)
- Industry and Government led working groups such as those overseen by the Smart Grid Forum and Smart Grids GB
- Ofgem
- Department of Business Energy and Industrial Strategy
- Academic Institutions
- The Institute of Engineering & Technology
- Local Government Authorities
- Trade Associations (including the Renewable Energy Association and Renewable UK)
- Renewable generation developers
- Aggregators
- End consumers

5.2.1.3 Dissemination Channels

Due to the range of stakeholders in the TDI 2.0 project the style of sharing information should be tailored to suit each audience type based on their requirements. The stakeholder should be central to any knowledge dissemination activity; by adopting a bi-directional information transfer process, learning opportunities will be maximised and stakeholders will be able to provide feedback on the project to the project manager and team. This type of process will also allow project partners to input any potentially useful external views which will ultimately increase the value of the project.

The knowledge obtained through the project will be shared by using a variety of methods and communications media, including but not limited to:

- Specific training and familiarisation material and workshops for National Grid and UK Power Networks staff and other Distribution Network Operators
- Regular project stakeholder meetings
- Regularly scheduled customer engagement sessions
- Conferences and workshops
- Speaking opportunities at externally organised conferences and events
- Newsletters
- Reports, technical data and analysis
- Industry working groups and forums
- Dedicated project pages on National Grid and UK Power Networks' Innovation website as well as project specific content on partner websites
- Videos
- Press releases and articles, particularly in trade press, blogs and other social media, such as Twitter

5.3 IPR

The project will conform to standard NIC intellectual property rights requirements. Whilst a full contractual negotiation has not been completed at this stage, all participants who responded to the RFI (Request for Interest) accepted these without modifications. Therefore, as part of the RFP (Request for Proposal) process and selecting the technical partner, the RFP will include a model contract agreement containing terms and conditions required by the NIC and we expect minimal modifications to be requested.

Section 6 Project Readiness

Requested level of protection required against cost over-runs (%): 5
Requested level of protection against Direct Benefits that they wish to apply for (%): 50

6.1 TDI 2.0 Project will start in a timely manner

A number of key activities have been initiated / completed during the preparation of the full submission which ensures that the project is ready to fully start at the beginning of January 2017:

- Project governance and management arrangements are defined in Section 6.4: This ensures that there is a clear and understood structure to the project from kick off.
- In-depth analysis of the project objectives and requirements has been undertaken, resulting in the development of a well-defined scope and description for each work stream. This is shown in detail in Appendix 9.
- An established TDI 2.0 team comprising dedicated project management, technical and commercial teams will ensure the timely implementation of the project whilst the project specific resource is allocated and mobilised.
- In order to demonstrate value for money and optimum preparation for a timely start, during the course of the preparation of the full bid submission, we have:
- Issued a request for qualifications;
- Received and evaluated initial supplier responses;
- Issued a full request for proposals;
- Received and evaluated full submissions; and,
- Down-selected to our preferred vendors.
- By the start of the project, we will have finalised the specifications and completed the procurement process, meaning that the project delivery team will make an impact from day one on a typically long lead-time element of the project.
- Identification of risks that could potentially delay the start of work at work stream level, and where appropriate, will proactively mitigate these issues by initiating activities before aware notification at National Grid Electricity Transmission and UK Power Network's risk. The two main activities requiring early initiation are resourcing and drafting of partner agreements, which will be addressed during the submission evaluation period.
- A detailed Project Plan outlining the activities, milestones and dependencies has been produced (Appendix 4). This plan will be continually reviewed and refined during the submission evaluation period to ensure that it is maintained as a fully comprehensive, accurate and up-to-date plan for project delivery starting at the beginning of January 2017.
- An active risk register, with mitigation and contingency plans in place has been prepared (Appendix 5). As with the project plan, this will be continually reviewed and refined during the submission evaluation period to ensure that it is maintained as a fully comprehensive, accurate and up-to-date reflection of project risks and mitigations in place for project delivery starting at the beginning of January 2017.
- A clearly defined project organisation chart has been developed (Appendix 7) which details the governance and management arrangements, and demonstrates that we have the people in place that have the authority, responsibility and knowledge to make the key decisions in an effective and timely manner. Through the submission evaluation period we will transition from the bid team to the enduring project team, where a number of the bid team will be part of the enduring project team, to ensure continuity. The enduring project team will be in place to commence the project at the beginning of January 2017.
- Continual engagement with the project directors and project managers of National Grid Electricity Transmission and UK Power Networks and their existing portfolio of NIC

projects ensures a detailed understanding of lessons learnt on other projects, which can be applied to this project.

6.2 Senior management commitment

The project has been developed in conjunction with National Grid Electricity Transmission and UK Power Networks senior management who have demonstrated management commitment and ensured the availability of input and support from in-house specialists. Management commitment has been achieved through regular presentations at executive management team meetings and also at senior management team meetings within relevant directorates.

Support from in-house specialists has been achieved through regular project meetings with senior managers and other senior discipline leaders with expertise in a number of areas including IT systems and network planning.

We have engaged with both National Grid Electricity Transmission and UK Power Networks senior management, each of whom have provided inputs on the project scope, delivery phases and success criteria. The experiences and guidance in their areas of expertise has enabled a robust project to be prepared.

6.3 How the costs and benefits have been estimated

To ensure robust and realistic costs, these have been calculated with a bottom-up approach across each of the project work streams. The project costs estimates are based upon:

- Inputs from a number of National Grid Electricity Transmission and UK Power Networks experts for labour requirements, including for procurement, legal and dissemination activities.
- Inputs from National Grid Electricity Transmission and UK Power Networks technical specialists including labour elements for IT system integration activity and equipment installation for the trials.
- Quotations received from the partners and suppliers, benchmarking where possible and utilising procurement expertise in specific areas to challenge costs and leverage existing commercial arrangements with suppliers.
- A rigorous full cost and scope review was carried out independently to ensure that costs are accurate and provide value for money.

The method costs have been carefully prepared with detailed procurement costs identified during the submission bid phase, including costs determined from the competitive tendering process.

Benefits have been determined for the project method described, along with benefits of a wider rollout to GB. Careful consideration has been given to the calculation of potential benefits, which are based on:

- Professional / engineering judgement.
- Verifiable and credible sources for unit costs.
- Extensive modelling of the South East network.

In all instances a conservative approach has been taken, where more detailed information on the cost benefit analysis (CBA) is provided in Appendix 10.

6.4 Measures employed to minimise the possibility of cost overruns or shortfalls in Direct Benefits

To support the delivery of a quality project to both budget and timely delivery, project management will be based on industry leading and proven National Grid Electricity Transmission and UK Power Networks delivery methodologies, and established governance processes. The project has a procurement component and establishing suitable suppliers and identifying competitive costs has been a key focus during the full submission preparation. The detailed cost evaluation was used to ascertain the project costs, and this is detailed in the full submission spreadsheet found in Appendix 2. In addition, a risk register has been prepared which details the identified risks and mitigation strategies, and can be found in Appendix 5, of which National Grid Electricity Transmission and UK Power Networks have ownership.

Project delivery and governance controls have also been defined, which includes:

- A Project Steering Group comprising the key stakeholders and decision makers within National Grid Electricity Transmission and UK Power Networks, including the project sponsor and senior responsible officers. This group is ultimately responsible for the project and will make decisions that have an overall impact on the benefits and outputs that the project will deliver. They will assess major change requests, review the impact on the project business case, and identify and review risks or issues associated with major change requests.
- Twice-monthly reporting to the Project Steering Group and to the executive management team by the project leads to provide regular review points and allow full financial and project control.
- A Project Board, comprising the project manager, work stream managers and programme management officer, will meet fortnightly. The Project Board is responsible for the operational management of the project, focused on reviewing progress against the plan, and resolving any risks or issues. They will also approve change requests within a defined tolerance and prepare change requests for submission to the Project Steering Group for major changes.
- A regular risk review will be undertaken by the project manager with results reported to the project sponsor and Project Steering Group.
- A design authority who will review and approve all key project deliverables, with ultimate responsibility for the overall solutions being delivered by the project. Change requests may be initiated by the design authority directly or by the work streams. Change requests initiated by the work streams will be reviewed by the design authority prior to submission.
- Management of work streams in accordance with milestone plans supported by detailed project plans and a clearly defined list of deliverables from each work stream. Each of these will be produced in consultation with our project partners to ensure a strong foundation for clarity of scope, objectives, approach and deliverables.
- A robust change management procedure to ensure that change request impacts are fully analysed at the appropriate level of authority depending on the scale of the change.
- Quarterly project partner / supplier reviews will track and discuss progress and risks to project delivery.

6.5 Accuracy of information

National Grid Electricity Transmission and UK Power Networks have endeavoured to ensure all of the information included within this full submission is accurate. Information included within the proposal has been gathered from within National Grid Electricity Transmission, UK Power Networks, the project partners, suppliers and other subject matter experts. All of this information has been reviewed to confirm and refine understanding, whilst evaluating the validity and integrity of the information.

A bid team, incorporating a full time bid lead and design authority, has worked with partners to prepare and review the bid. Project partners have also ensured information provided by them has been through a thorough internal review and approval process before being provided to National Grid Electricity Transmission and UK Power Networks.

6.6 TDI 2.0 Project will deliver learning irrespective of the take up of low carbon technologies and renewable energy

This project will explore the potential for a control system stationed at distribution level to control the operating mode of DER connected to Grid Supply Point's (GSPs) in the South East. This innovative TDI 2.0 approach will determine if dynamic reactive response from DER is feasible and effective in resolving voltage transmission constraints.

The learning outcomes of the project will be delivered without a dependence on the speed of take up of low carbon technologies or distributed generation in the trial areas. Throughout the project, details of lessons learned will be maintained by the Project Manager supporting the continual capture and transfer of knowledge to partners and internal / external stakeholders. This is expected to include equipment procurement, control systems installation and overall system operations.

6.7 Processes are in place to identify circumstances which could affect successful delivery of the project

As part of the National Grid Electricity Transmission and UK Power Networks joint governance there are number of processes in place to identify, assess and manage any issues that may affect the project. These processes help to maintain the smooth running of the project, whilst also aiding to identify the most appropriate course of action at any point.

The National Grid Electricity Transmission and UK Power Networks project governance and control process has a gate approval process which reviews the project at critical stages throughout its life-cycle. The project must meet the mandatory entry/exit criteria for any particular gate (which takes into account risks, issues, benefits realisation and financial position), which the project manager will need to provide evidence.

A risk management and contingency plan is used to identify, analyse, control and review all of the risks, whilst calculating the potential cost impact. We have identified these potential risks to the project and have put mitigation actions in place to ensure the success of the project. A full risk register is included in Appendix 5. The project manager is responsible for ensuring all risks and issues are effectively managed and those above the agreed tolerance are escalated to the Project Steering Group. The Project Steering Group has overall responsibility to determine whether the most appropriate course of action would be to suspend the project, and will do this with guidance from Ofgem.

Section 7 Regulatory Issues

7.1 Data Confidentiality

The technical data required for the TDI 2.0 project is the data currently shared between National Grid and UK Power Networks under the Grid Code (i.e. provision of data from DNOs as part of Week 24 data submission, and between National Grid and DNOs as part of Week 48 data submission), and as part of the trial of TDI 2.0. There is no requirement for any derogations or license exemptions.

As part of the project trial, commercial data (pricing) will be received from Distributed Energy Resources (DER). This information will need to be shared between UK Power Networks and National Grid Electricity Transmission for the purpose of TDI 2.0. The commercial workstream will verify that such data sharing is compatible with the existing rules and regulations.

7.2 Balancing and Settlement Code

National Grid procures Balancing Services in order to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System. In accordance with the Transmission Licence, National Grid is required to establish and publish statements and guidelines on Balancing Services.

They are procured in line with the framework set out in National Grid's Transmission Licence, in Condition C16. C16 places a requirement on National Grid to establish and publish statements and guidelines on Balancing Services [1]. This requirement provides assurance that the flow of electricity onto and over the national electricity transmission system is co-ordinated and directed in an efficient, economic and coordinated manner and that there is no discrimination between any persons or classes of persons in the procurement or use of balancing services having taken into account relevant price and technical differences.

National Grid has extensive experience of implementing mechanisms to access Balancing Services from distributed resources, the most recent example being the Demand Turn Up[2] service. National Grid will apply its experience in Balancing Service development to the TDI2.0 project and ensure that the capabilities the project will develop can be integrated into efficient, economic and co-ordinated arrangements for services and capabilities.

In addition to any Balancing and Settlement Code changes, the project's commercial workstream will develop any necessary change proposals to the documents National Grid is obliged to establish and publish under its Licence condition C16 (for example, the Procurement Guidelines).

From the commercial prospective the innovation is another way of route to reactive market through Distribution Network Owner and coordination with all other existing commercial frameworks already existing between SO, distribution network owner and aggregators.

---

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Transmission-License-Condition-C16-Statements/
[2] http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Demand-Turn-Up/

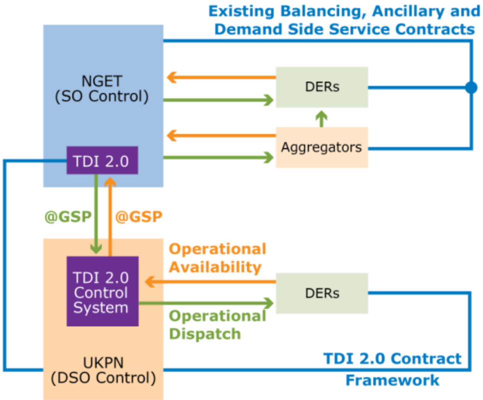


Figure 7.1 Coordination between TDI 2.0 and other balancing services

7.3 DNO revenues

The primary purpose of TDI 2.0 is to facilitate the use of DER flexibility by National Grid Electricity Transmission, not for UK Power Networks to generate revenues as a service provider. However, it is possible that in facilitating that relationship there could be situations in which the DNO receives a residual net revenue or expenditure. If this occurs during the trial, these revenues or expenditures will be netted against the commercial contingency trial funds.

Condition 29 of the Distribution Licence prevents the licensee from carrying out activities other than those of a Distribution Business. Two exceptions to this restriction do exist. The first is for the Authority to give its consent for the licensee to engage in other activities. The second requires the other activity to qualify as a de minimise activity, meaning that neither turnover nor investment associated with the other activity exceeds 2.5% of the Distribution Business turnover or share capital, share premium and consolidated reserves respectively. If any of the commercial services (e.g. provision of flexibility to National Grid Electricity Transmission) were not to be deemed activities of a Distribution Business, the activities under this project would fall within the de minimise category and an Authority consent is therefore not required.

The project's commercial consider will consider any changes and develop change proposals to the Distribution Licence / Distribution Code that might be required to enable wider rollout of the methods if successful.

In addition, Section 9(1) of the Electricity Act 1989 (as amended) and Condition 4 of the Distribution Licence require the licensee to promote/not distort competition in the generation or supply of electricity. UK Power Networks believes that this project is supportive of the aim of promoting competition in generation or supply of electricity.

7.4 Future of the Smart Grid

This project has the potential to inform a number of aspects of a future Smart Grid and Distribution System Operator (DSO) model. However, its primary focus is on developing a practical technical and commercial solution to use DER flexibility for the DNO and National Grid Electricity Transmission. As such, the intention is to operate the trial within the existing regulatory framework.

However, it is expected that some of the lessons to emerge from the trial will relate to the regulatory framework, and to modifications that may enable the approach to operate more effectively or at a lower cost to consumers. It is assumed that such changes would not be made within the trials timescales, so would be included as recommendations for further work and eventual roll-out.

Section 8 Customer Impact

The trials for this project are designed to demonstrate the effectiveness of the concept and delivery of the service while not increasing risk to either transmission or distribution system. The trial and individual testing proposed will also be designed so as not to impact on the general customer base within the distribution network.

The participation of customers in the TDI 2.0 project will be voluntary. The project will target both existing and future renewable generation customers interested in trialling the technical and commercial solutions proposed by this project.

8.1 Existing generation customers

For generation customers within the trial area who already have a connection agreement with National Grid or UK Power Networks, the TDI 2.0 solutions will be proposed to these customers where potentially beneficial but they will have the option of retaining their existing access rights.

8.2 Future generation customers (no current offer)

For generation customers within the trial area who have not yet applied for a grid connection to the network area, where applicable, UK Power Networks will provide, within the GSoP license obligation window, both a conventional and an alternative grid connection offer, the latter based on novel technological and commercial solutions derived from the TDI 2.0 project. The implication of accepting the TDI 2.0 connection solution will be explained to the customer and the customer will be given a written explanation of the solution in addition to a draft contract to ensure they fully understand the choices they are being offered.

The exact strategy for customer engagement and the commercial contract templates for the TDI 2.0 offering form some of the first project deliverables.

It is envisaged that the commercial team will initiate contact and provided information to the potential generation customers in the area regarding the project scope, objectives and offering.

Both National Grid and UK Power Networks are fully committed to ensuring that customers participating in the TDI 2.0 project trials are fully informed.

8.3 New generators (outstanding offer)

For generation customers within the trial area who have previously received a connection offer (which is valid for 90 days) but have not yet accepted it the following arrangements will apply:

- For customers still within the 90 days' timeframe, UK Power Networks, through the commercial work stream, will approach these customers to identify whether they will consider receiving an alternative connection offer based on the solutions within the trial;
- Where a grid connection offer has expired this may be a result of simply finalising the contractual terms of the connection offer, in which case the generation customers will be considered an existing customer. However, where a previously issued connection offer has expired and UK Power Networks has not been invited to begin detailed negotiations of contractual terms, the generation customer will be required to re-apply for a connection offer, as per existing practice, and therefore will be treated as if they are a new generation customer (i.e. there is no existing current offer);
- Once new or existing customers have agreed to participate in the trials, they may experience some constraint to generation export. At the end of the trials, the extent of the constraint will be evaluated to ensure that it has not exceeded the constraint

agreed in the customer's connection agreement or amended agreement. Monitoring equipment installed as part of the TDI 2.0 project will allow this to be fully assessed.

8.4 Customer engagement and education

There is no restriction, in principle, on the types of DER that should be able to participate in the TDI 2.0 scheme, provided they are technically capable and their size is sufficient to justify installing the ANM equipment. The purpose of the market engagement is to ensure a sufficient volume of capability is brought within the framework, and that this volume comes from a sufficient diversity of technologies. It is intended to have representation from DER, batteries (or other storage devices), and DSR. It is also important that, as part of the market engagement, sufficient information is provided to allow developers to understand what they would be committing to, and to allow them to participate in the tenders from an informed position.

In order to achieve these goals, the following market engagement process is proposed:

- Repeat the Expression of Interest (EoI) call that was held as part of the bidding process
- Hold stakeholder event for DER and aggregators to provide information on the project and planned tender
- Existing DER in the region will be contacted directly and provided with information on the project and the planned tender process
- As part of the connections process, DER will be provided with information on the scheme as supplementary information; this is expected to be in addition to the Flexible Connection offer they would be made.
- Open teleconference (repeated every 4 months) to relay the project design, including the opportunity for participants to send in questions, which will either be addressed as part of the teleconference or in a follow-up email
- Targeted consultation (focusing on those DER and aggregators that have expressed an interest) on the design of the tender, including the minimum technical requirements, availability windows, bidding blocks (i.e. the subdivision of hours across the day), allowed combinations of bids, proofs required for as-yet-unconnected DER to participate, time between tendering and first delivery window, number and frequency of tender rounds, and the duration and number of tender periods (i.e. the length of time DERs will be able to secure future revenue).
- Circulation of proposed tender process to wider audience to garner feedback and make changes where deemed necessary (in conjunction with the Market Advisory Panel)
- Seek soft commitment from DER and aggregators via an Intention to Tender call in order to anticipate the expected uptake. The responses will be reviewed, and if deemed necessary (e.g. low volumes anticipated, small numbers of bidders (even if they are offering large volumes), or specific key technologies are absent) further direct engagement will take place and, in extremis, the tender would be delayed to ensure increase in participation.
- Publication of tender round on the UKPN and National Grid websites. There will be opportunity for further engagement and, if required and only in consultation with the Market Advisory Panel, modifications made to the tender design may be made to improve uptake and competitive bidding

8.5 Customer Interruptions

The TDI 2.0 project is concerned with a generator dominated 132kV and 33kV network group. Planned network outages will be necessary to install certain devices such as:

- Voltage and current transformers (for measurement purposes)

- Upgrades to tap changer relays

While such network outages will inevitably increase the risk of customer interruptions due to a second fault outage, such risks will be minimised through normal planned outage risk management procedures.

It follows that no customer interruptions are envisaged and the project therefore does not need to request protection in respect of the Interruption Incentive Scheme.

To further de-risk the likelihood of Customer Interruptions a rigorous end to end solution testing phase has been planned to ensure that all aspects of the solution are functional before going live with the trial.

The trial itself will be delivered in stages, in which more and more DER participants will be included into the trial, and the selection of these DER will be based, amongst others, on their calculated response effectiveness per GSP and readiness to take part in the trial. Throughout the stages, the learning outcomes will be monitored closely to ensure that there is sufficient evidence that the next stage can proceed.

A high level view of the trial methodology is presented in the following table. More detail on trials can be found in Section 2.

TDI 2.0 TRIAL					
YEAR	2018	2019			
	Functional Testing	Q1	Q2	Q3	Q4
Stages		Stage 1	Stage 2	Stage 3	Stage 4
Participating DER (based on SF)		Includes new participants at each stage starting from the most effective ones in stage 1 onwards.			
Use Cases (as applicable)		1 to 5			
Learning Outcomes		Initial results → Robust results			

8.6 Learning and Dissemination

Learning and dissemination is an integral part of the project with dedicated project resources, more detail in Section 5 and Appendix C. Our approach employs a range of communication methods and channels to engage with and impart information to our customers and/ or stakeholders.

The TDI 2.0 Project is a technical and commercially complex project and so we have decided not to directly engage with domestic customers during the project. However, we will, as is normal with National Grid and UK Power Networks innovation projects, publish all the generated materials on the relevant websites enabling any of our customers or stakeholders to download information or raise any questions, if they wish.

Throughout the Project we will engage with our stakeholders via tailored communications which will be a combination of working groups, written, audio and visual mediums.

8.7 Managing Customer Enquiries

We will create a number of communication channels so that customers will find it simple to raise any questions or concerns at a time convenient for them using the following channels:

- Customer Engagement Sessions – a regularly organised event where customers and other industry stakeholders receive Project updates and can ask questions
- Telephone – National Grid and UK Power Networks operate an enquiry service that is continuously staffed and can be contacted
- TDI 2.0 Website – The website will contain all relevant information including Trial areas, customer Q&A, project literature, and relevant contact details. If the customer is unable to find an answer to the specific issue, a "Contact Us" will allow them to submit their query and a representative of the team will respond via the customers preferred feedback method.

Section 9 Successful Delivery Reward Criteria (SDRCs)

Criteria		Evidence	Date
SDRC 9.1	**Technical High Level Design** – the high level design of the technical solution and high level business processes which will operate the solution	• Alternative design options considered and selection criteria • High level design specification • Functional design document • High level business processes • Review of anticipated synergies and conflicts	03/07/17
SDRC 9.2	**Stage Gate 1 – Commercial and Detailed Technical Design** – the agreed detailed technical design (Partner/s, National Grid, UKPN and Customers) and Commercial Framework for the trial	• Stakeholder consultation findings • Functional Specification Documents • Finalised Commercial Framework • Detailed Business Processes	01/01/18
SDRC 9.3	**Stage Gate 2 – Commercial Tendering Process Report and Finalised Trials Approach** – outline the learnings from the tendering rounds for the reactive power services and the engagement on the active power services and advise based on this process and the trials approach which customers will be utilised during each trial phase and the forecasted effectiveness	• Report on tendering approach, including technical and contractual requirements for participation, barriers to entry and measures to alleviate these • Proposed commercial framework and interaction with SO and DNO incentives • Review of technologies and volumes under contract • Initial forecasts of availability and utilisation volumes • Signed commercial contracts • Trials Approach and Methodology	02/07/18
SDRC 9.4	**Stage Gate 3 – Customer Readiness Report and Performance of the Technical Solution in Controlled Environment** – update on the effort required to ready customers to take part in the trial (technical, business processes etc.) and the performance of the technical solution in a controlled environment and expected performances in the live environment	• Test Report – End to End testing • Business Change Implementation Report • Customer Readiness Assessment • Technical Solution – GO / NO-GO Criteria Results • Customer and Business – GO / NO-GO Criteria Results	31/12/18
SDRC 9.5	**Cost Benefit Analysis** – analysis assessing the financial case for the trial to date and for extending the approach into the future	• Detailed assessment of the costs and benefits of TDI 2.0, to include: ◦ analysis of the net benefit of extending the trial into the future (using Ofgem's CBA framework), • replication study assessing the viability of, and case for, extending	31/12/18

		TDI 2.0 to other DNOs and for providing a wider set of services	
SDRC 9.6	**Stage Gate 6 - Trials Report** The completion of the trials in line with customer agreements and review of the performance of the trial; the closure of the project (potentially moving into BAU) in line with customer agreements	• Trials Phase Report including adequacy of contracted volumes to meet requirement, availability/reliability of DERs and control system, accuracy of sensitivity and accuracy forecasting, evidence of competitive bidding, evidence of conflicts • Report summarising the financials of each party (subject to DER commercial confidentiality), an in particular the costs incurred by the DNO, the uplift applied to DER bids, and hence the net revenue that the DNO receives • Assessment of scheme design and operation to cover how well it worked, where conflicts arose, and • how the governance arrangements performed • Plan for transitioning trial participants into enduring solution Updates to SDRC 9.5 and 9.6 (if required) based on the output of the trials	30/12/19
SDRC 9.7	**DSO risk-reward framework for providing wider system services** – a paper describing the incentive framework used for the project and recommendations for an enduring incentive framework for an active DSO	· Analysis of the costs, risks and revenues for the services included in the trial · Assessment of mechanism used within the trial and comparison against alternative incentive mechanisms • · Assessment of the applicability of these incentive schemes to a DSO providing a broader set of system services and interaction with the wider SO incentives	31/12/19

Section 10 List of Appendices

Appendix	Description
1	Benefits Table
2	Full Submission Spreadsheet
3	Maps & Network Diagrams
4	Project Plan
5	Project Risk Register, Risk Management & Contingency Plans
6	Technical Description
7	Organogram
8	Project Partners
9	Work Stream Descriptions
10	Cost Benefit Analysis
11	Letters of Support
12	Glossary

Appendix 1 Electricity NIC Financial Benefits

Key

Method	Method Names
Method 1	Dynamic Voltage Control from Distributed Energy Resources with reactive compensation in transmission system only
Method 2	Dynamic Voltage Control from Distributed Energy Resources with reactive compensation in transmission and distribution system

Cumulative net financial benefit (NPV terms; £m)									
Scale	Method	Method Cost	Base Case Cost	Benefit				Notes	Cross-references
				2020	2030	2040	2050		
Post-trial solution *(individual deployment)* *Limited to South East of the Network (TDI 2.0 direct financial benefits)*	Method 1	16.22	24.80	0.68	10.30	19.03	25.70	There are two assumptions in the approach that may foreseeably lead to variation in future benefits. The cost of reactive compensation is held constant although space restrictions may increase prices as a consequence of cumulative installation although technological advances may counter this. Also technological advances may well drive down the cost of reactive power provision from DG.	Full calculations for the Cost Benefit Analysis and assumption used for the calculations are presented in Appendix 10 – Cost benefit Analysis.
	Method 2	15.04	24.80	0.76	11.02	20.60	27.99		
GB rollout scale *Rollout to 59 GSP in the GB system (greater London and greater Midlands)*	Method 1	239.24	365.80	10.03	151.92	280.69	379.07	59 sites make up the greater urban areas of London and the Midlands where National Grid has seen the sharpest decline in reactive power demand. These locations where space is restricted are seen to offer the greatest benefit from releasing reactive power compensation from DG. Potential benefits could arise from the remaining 135 GSPs in England and Wales but these have not been included in this analysis.	
	Method 2	221.84	365.80	11.21	162.54	303.85	412.85		

Note related to Network Capacity Release and Carbon Benefits Tables:

On the tables Network Capacity Released and Carbon Benefits are considered as Not Applicable for the TDI 2.0 approach as the network capacity released in MW capacity terms are the same in today's model and those used in the innovative approach TDI 2.0. This means that the same scenario for the Distributed Energy Resources connection is used in the today's model as in the TDI 2.0 approach.

Network capacity released: As it is explained in details in the Cost Benefit Analysis document in Appendix 10, the scenario for DERs connected was received from Regulatory and Strategy team from UKPN. The same scenario was used as the assumption in the TDI 2.0 approach. Therefore the TDI 2.0 approach does not release additional capacity in comparison to what could be connected in the business as usual approach however, we are releasing the capacity in more cost beneficial way than today' model approach. Based on amount of network MW capacity, our calculation showed that we would be able to connect 3720MW of DERs, taking into consideration diversity factor between 70 – 100%.

Carbon reduction benefits –As the TDI 2.0 approach does not release any additional network capacity in comparison to business as usual approach, there is no additional carbon benefit with TDI 2.0. Sections 3 and 4 explained the carbon reduction results which are related to network capacity obtained and the numbers are associated with carbon reduction costs. That numbers are equal in business as usual and in the innovative TDI 2.0 approach. However, the innovative TDI 2.0 approach will potentially stimulate more DER connection, which potentially could bring additional carbon benefits.

Therefore, as there are no additional benefits in network capacity released or carbon benefits in comparison to Business as Usual method. However, there is direct financial benefit in the TDI 2.0 approach in comparison to today's model and potentially a faster and more efficient connection of future DERs.

Appendix 2 Full Submission Spreadsheet

This document has been submitted as a separate file.

Appendix 3 Maps and diagrams

The transmission system on the South East Coast is a 212km, 400kV double circuit routed between Kemsley in North Kent and Lovedean near Southampton. It is interspersed with existing substations at Bolney, Ninfield, Sellindge, Canterbury and Cleve Hill.

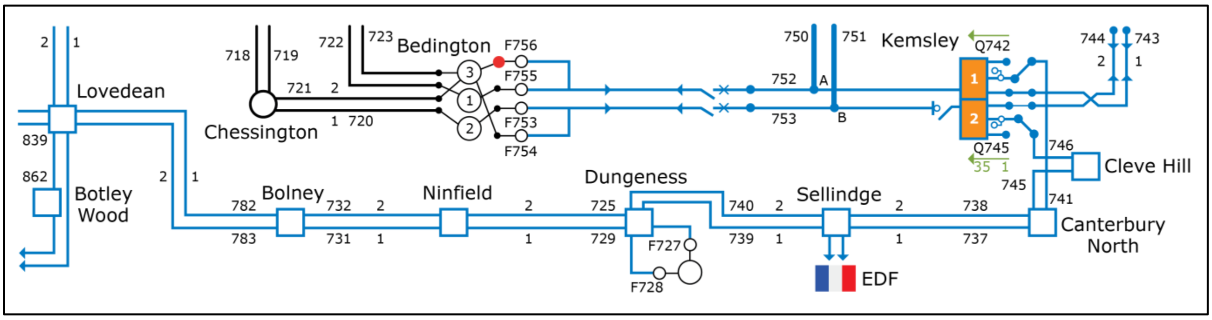


Figure A3.1 Current transmission network - South East

With the introduction of the NEMO interconnector to Belgium in 2018, the transmission and distribution networks will change with the addition of Richborough 400kV substation which will serve as an additional GSP to the distribution network.

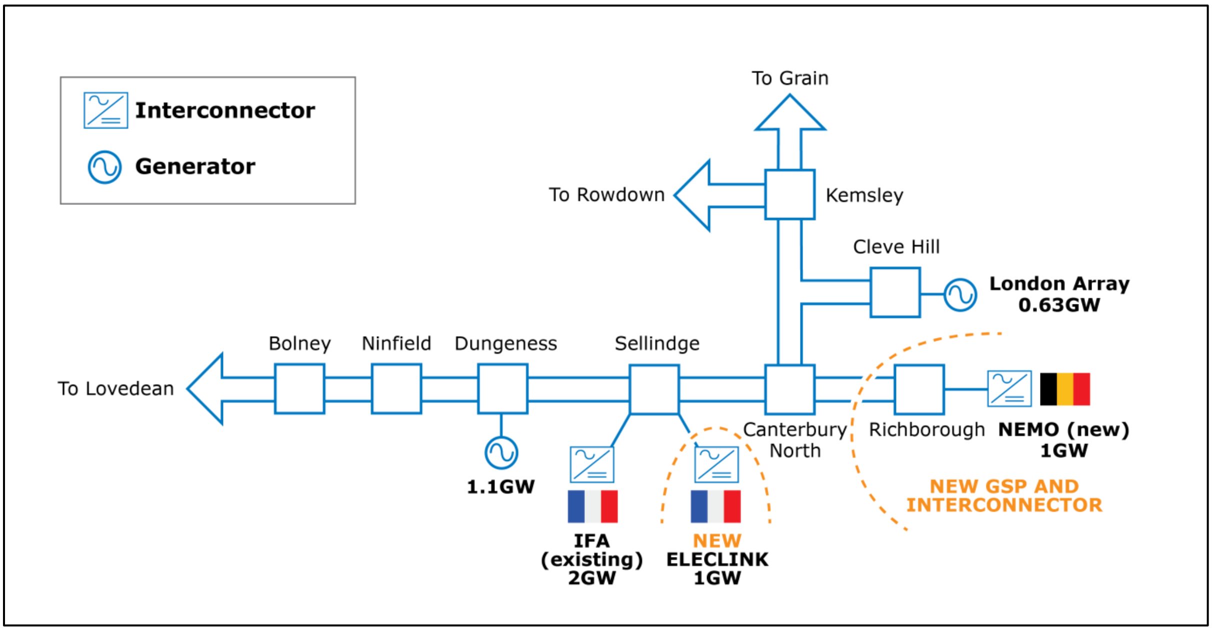


Figure A3.2 Future transmission network - South East

The TDI 2.0 project will focus on four GSPs in the area: Bolney 400/132kV, Ninfield 400/132kV, Sellindge 400/132kV and Canterbury 400/132kV as shown below. These GSPs supply over 1.1million customers via numerous 132kV, 33kV and 11kV substations.

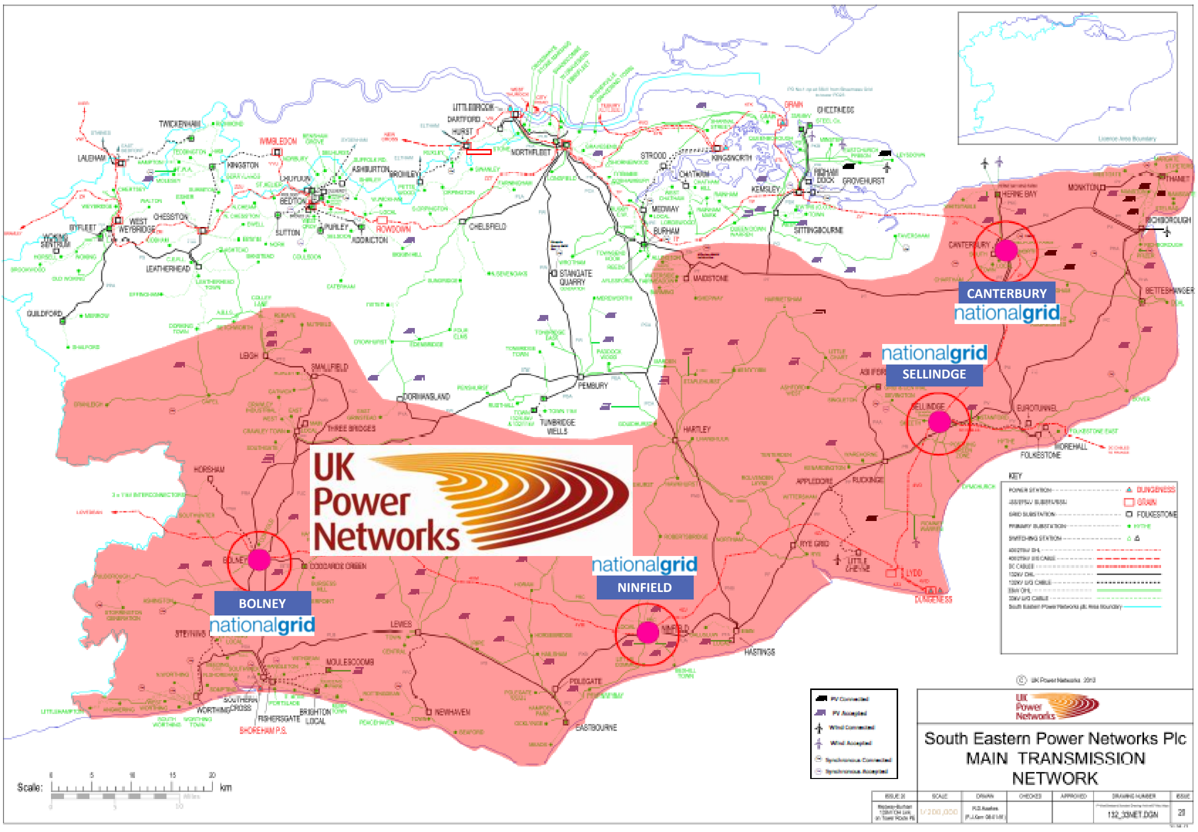


Figure A3.3 Project area of interest

The South Coast GSPs are interconnected directly at 132kV on the distribution network between Sellindge - Canterbury and through loose couples at 33kV between Bolney - Ninfield and Ninfield – Sellindge. Simplified diagrams of the 132kV network of the TDI 2.0 project area, including connected generation, are shown in Figure A3.4 and Figure A3.5. These diagrams do not include contracted generation in the area.

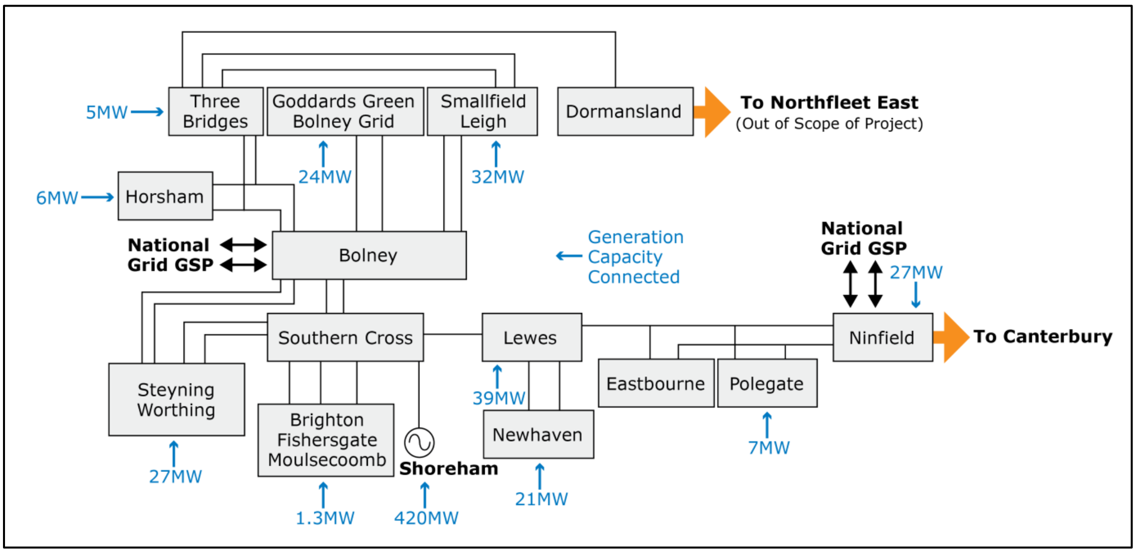


Figure A3.4 Simplified diagram of132kV UKPN network Bolney to Ninfield

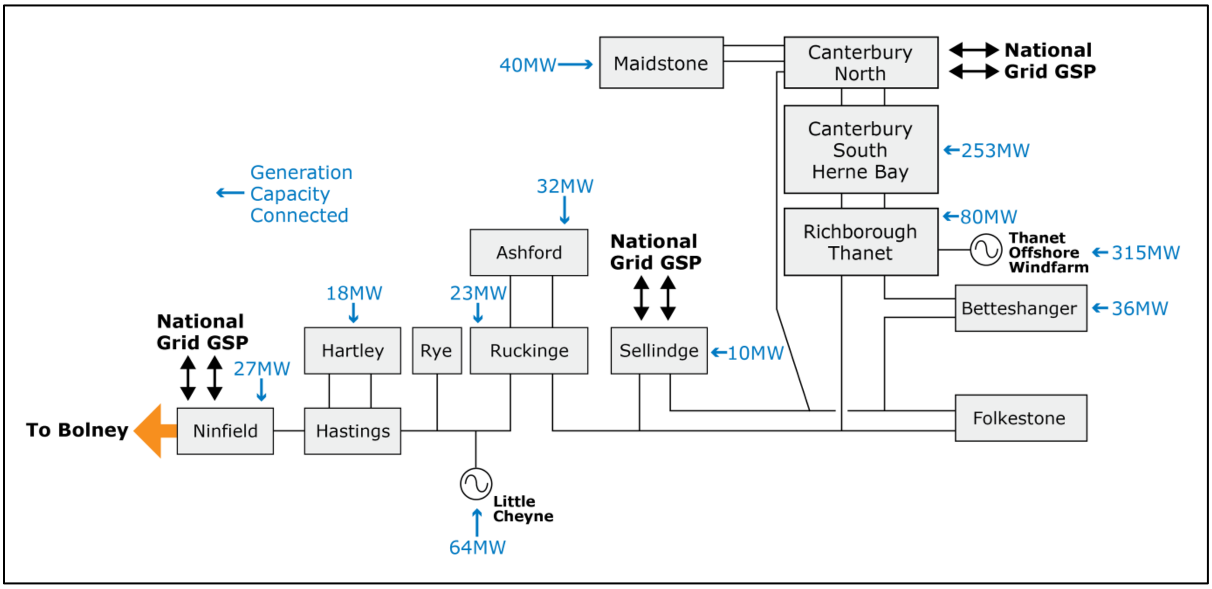
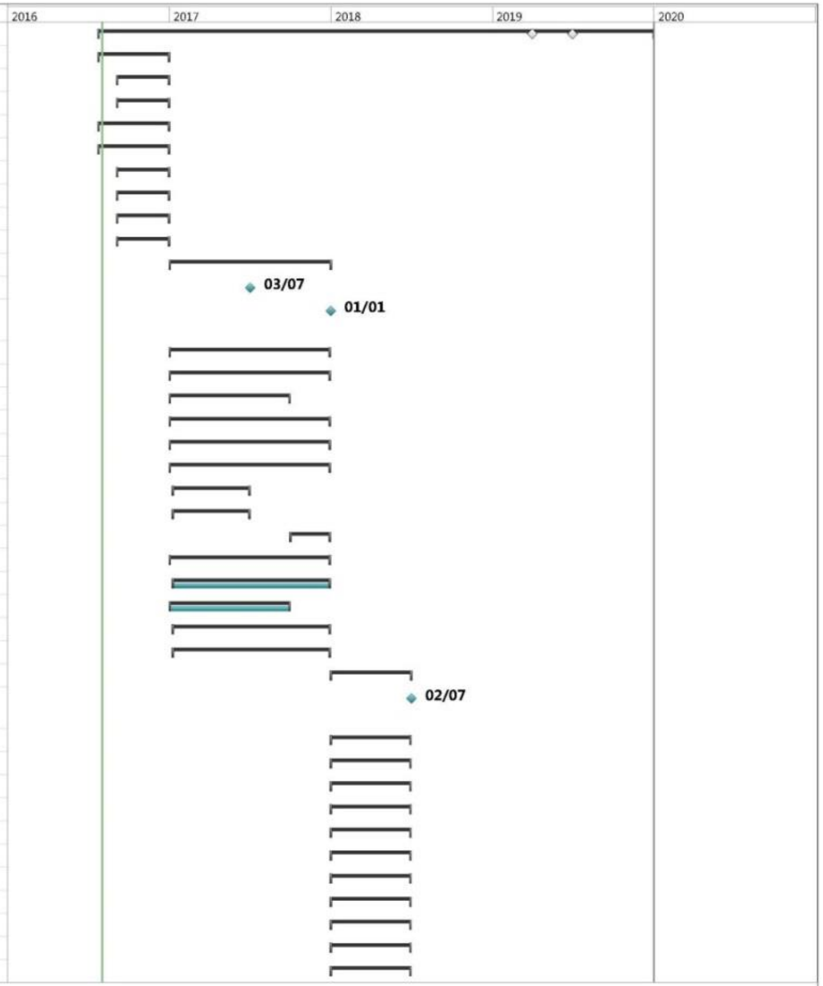


Figure A3.5 Simplified diagram of132kV UKPN network Ninfield to Canterbury

Appendix 4 Project Plan

ID	Task Name	Duration	Start	Finish
1	**TDI 2.0 Project Plan**	**897 days**	**Mon 25/07/16**	**Tue 31/12/19**
2	**Phase - Pre-Contract Award**	**115 days**	**Mon 25/07/16**	**Fri 30/12/16**
3	**Project Management Office (PMO)**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
4	**Project Office**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
7	**WS1 - Technical Solution Delivery**	**115 days**	**Mon 25/07/16**	**Fri 30/12/16**
8	**Architecture**	**115 days**	**Mon 25/07/16**	**Fri 30/12/16**
12	**Functionality**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
16	**WS2 - Commercial**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
17	**Customer**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
19	**Bi-Lateral Agreement**	**85 days**	**Mon 05/09/16**	**Fri 30/12/16**
21	**Phase - Design**	**260 days**	**Mon 02/01/17**	**Mon 01/01/18**
22	SDRC 9.1 - Technical High Level Design	0 days	Mon 03/07/17	Mon 03/07/17
23	SDRC 9.2 - Stage Gate 1 - Commercial and Detailed Technical Design	0 days	Mon 01/01/18	Mon 01/01/18
24	**Project Management Office (PMO)**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
25	**Project Office**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
28	**Knowledge Dissemination and Comms.**	**195 days**	**Mon 02/01/17**	**Fri 29/09/17**
32	**Project Design Authority**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
35	**WS1 - Technical Solution Delivery**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
36	**Architecture**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
45	**Functionality**	**125 days**	**Mon 09/01/17**	**Fri 30/06/17**
46	**Power System Analysis Validation**	**125 days**	**Mon 09/01/17**	**Fri 30/06/17**
51	**Delivery & Integration**	**65 days**	**Mon 02/10/17**	**Fri 29/12/17**
54	**WS2 - Commercial**	**260 days**	**Mon 02/01/17**	**Fri 29/12/17**
55	**Customer**	**255 days**	**Mon 09/01/17**	**Fri 29/12/17**
59	**Commercial Framework**	**195 days**	**Mon 02/01/17**	**Fri 29/09/17**
63	**WS3 - Business Change**	**255 days**	**Mon 09/01/17**	**Fri 29/12/17**
64	**Business Readiness**	**255 days**	**Mon 09/01/17**	**Fri 29/12/17**
70	**Phase - Build**	**130 days**	**Mon 01/01/18**	**Mon 02/07/18**
71	SDRC 9.3 - Stage Gate 2 - Commercial Tendering Process Report and Finalised Trials Approach	0 days	Mon 02/07/18	Mon 02/07/18
72	**Project Management Office (PMO)**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
73	**Project Office**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
75	**Knowledge Dissemination and Comms.**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
77	**Project Design Authority**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
79	**WS1 - Technical Solution Delivery**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
80	**Architecture**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
82	**Delivery & Integration**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
87	**Testing**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
92	**WS2 - Commercial**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
93	**Customer**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
98	**WS3 - Business Change**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**

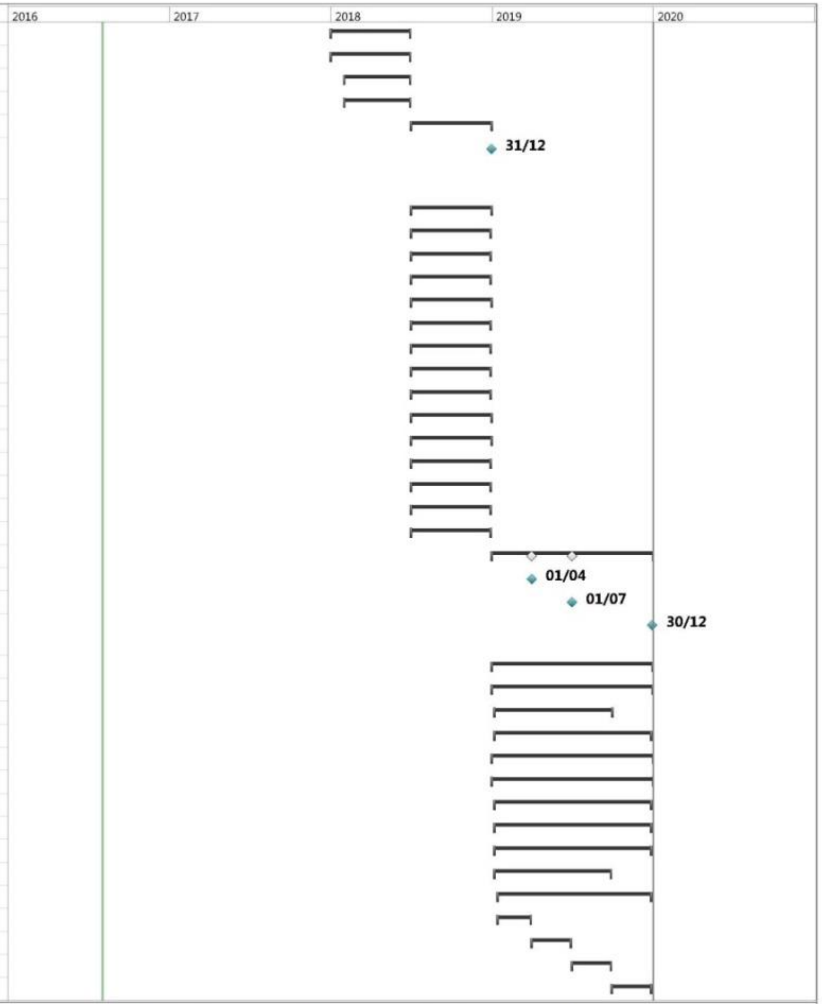


Project: NIC SESG (Summary fo
Date: Tue 02/08/16

Task | Split | Milestone | Summary | Project Summary | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | External Tasks | External Milestone | Deadline | Progress | Manual Progress

Page 1

ID	Task Name	Duration	Start	Finish
99	**Business Readiness**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
103	**Training**	**130 days**	**Mon 01/01/18**	**Fri 29/06/18**
106	**WS4 - Trials Delivery**	**107 days**	**Thu 01/02/18**	**Fri 29/06/18**
107	**Trials Design**	**107 days**	**Thu 01/02/18**	**Fri 29/06/18**
110	**Phase - Test**	**131 days**	**Mon 02/07/18**	**Mon 31/12/18**
111	SDRC 9.4 - Stage Gate 3 - Customer Readiness Report and Performance of the Technical Solution in Controlled Environment	0 days	Mon 31/12/18	Mon 31/12/18
112	**Project Management Office (PMO)**	**131 days**	**Mon 02/07/18**	**Mon 31/12/18**
113	**Project Office**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
115	**CBA**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
118	**Knowledge Dissemination and Comms.**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
120	**Project Design Authority**	**131 days**	**Mon 02/07/18**	**Mon 31/12/18**
122	**WS1 - Technical Solution Delivery**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
123	**Architecture**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
125	**Delivery and Intergration**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
127	**Testing**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
132	**WS2 - Commercial**	**131 days**	**Mon 02/07/18**	**Mon 31/12/18**
133	**Customer**	**131 days**	**Mon 02/07/18**	**Mon 31/12/18**
135	**WS3 - Business Change**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
136	**Business Readiness**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
138	**Training**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
143	**WS4 - Trials Delivery**	**130 days**	**Mon 02/07/18**	**Fri 28/12/18**
151	**Phase - Trial**	**261 days**	**Tue 01/01/19**	**Tue 31/12/19**
152	SDRC 9.5 - Stage Gate 4 - Trials Phase 1 Report	0 days	Mon 01/04/19	Mon 01/04/19
153	SDRC 9.6 - Stage Gate 5 - Trials Phase 2 Report	0 days	Mon 01/07/19	Mon 01/07/19
154	SDRC 9.7 - Stage Gate 6 - Trials Complete Report & Project Closure Report	0 days	Mon 30/12/19	Mon 30/12/19
155	**Project Management Office (PMO)**	**260 days**	**Tue 01/01/19**	**Mon 30/12/19**
156	**Project Office**	**260 days**	**Tue 01/01/19**	**Mon 30/12/19**
159	**CBA**	**191 days**	**Mon 07/01/19**	**Mon 30/09/19**
161	**Knowledge Dissemination and Comms.**	**255 days**	**Mon 07/01/19**	**Fri 27/12/19**
163	**WS2 - Commercial**	**261 days**	**Tue 01/01/19**	**Tue 31/12/19**
164	**Customer**	**261 days**	**Tue 01/01/19**	**Tue 31/12/19**
166	**WS3 - Business Change**	**255 days**	**Mon 07/01/19**	**Fri 27/12/19**
167	**Training**	**255 days**	**Mon 07/01/19**	**Fri 27/12/19**
169	**WS4 - Trials Delivery**	**255 days**	**Mon 07/01/19**	**Fri 27/12/19**
170	**Trials Readiness**	**190 days**	**Mon 07/01/19**	**Fri 27/09/19**
179	**Operational Support**	**250 days**	**Mon 14/01/19**	**Fri 27/12/19**
183	**Trials Phase 1**	**55 days**	**Mon 14/01/19**	**Fri 29/03/19**
187	**Trials Phase 2**	**65 days**	**Mon 01/04/19**	**Fri 28/06/19**
191	**Trials Phase 3**	**65 days**	**Mon 01/07/19**	**Fri 27/09/19**
195	**Trials Phase 4**	**65 days**	**Mon 30/09/19**	**Fri 27/12/19**



Project: NIC SESG (Summary fo
Date: Tue 02/08/16

Task		Project Summary		Manual Task		Start-only		Deadline	
Split		Inactive Task		Duration-only		Finish-only		Progress	
Milestone		Inactive Milestone		Manual Summary Rollup		External Tasks		Manual Progress	
Summary		Inactive Summary		Manual Summary		External Milestone			

Appendix 5 Project Risk Register, Risk Management & Contingency Plans

This is not an exhaustive risk register, but rather the top risks associated with project TDI 2.0

Risk No.	Workstream / Area	Risk Description	Cause	Consequence	Status (O/C)	Risk Owner	Likelihood (1-5)	Financial Impact (1-5)	Reputational Impact (1-5)	RAG	Escalate To	Mitigating Actions & Contingency
1	General	Final funding not awarded	Submission bid and evaluation period deemed not satisfactory to warrant awarding of funding for project	Project unable to commence in January 2017	Open	Project Manager	2	2	3	6	Project Manager	Ensure high bid quality, regular reviews, clear differentiation and stakeholder engagement.
2	General	Significant changes to the South Coast electricity system during the life of the project	Priorities or strategies for planning and managing the South Coast system may change	Solution may no longer by suitable. Assumptions may no longer be accurate or appropriate	Open	Project Manager	1	3	4	4	Project Manager	We have considered future developments and scenarios. We have ensured usefulness of solution matches..
4	General	Insufficient resources allocated for the project in time	Resources have other commitments	Project does not start in a timely manner	Open	Project Manager	3	2	3	9	Working Group	A project plan has been produced and partners have been asked to allocate resources to achieve the milestones. Budget allocation has been made for consultants/contractors to make sure project is resourced from the beginning and for all critical activities.

5	General	Critical staff leave National Grid, UKPN, or our project partners	Usual and unavoidable staff turnover results in key staff leaving National Grid, UKPN, or our project partners	Progress of the project is delayed. The expertise to deliver the project is no longer within the project team	Open	Project Manager	2	2	3	6	Project Manager	Knowledge of, and responsibility for, the project to not rest with one person. Ensure documentation and guidance exists to assist anyone joining project team. Thorough handover processes to be in place.
6	WS1 - Technical Solution Delivery	Technical limitations of ICCP interoperability between proposed control system and NG / UKPN communications link	ICCP cannot handle data transfer between transmission and distribution systems	Programme delay	Open	NGET / UKPN	2	1	2	4	Project Manager	Early engagement as part of bid preparation completed. ICCP trial involving all affected stakeholders to ensure operability at an early stage in project.
7	WS1 - Technical Solution Delivery	Technical specification is either to abstract or too descriptive	Insufficient engagement with partner(s) in preparing the technical specification	Specific issues may be unaccounted for due to an ambiguous specification. On the other hand, if the technical specification is too descriptive, this could prohibit further innovation from the different parties as it would restrict ingenuity	Open	NGET / UKPN	2	3	2	4	Project Manager	Produce a technical specification that has inputs from different areas of the business, as well as from the different partners, ensuring that it is not too prescriptive so as to impede further innovation during project delivery.

8	WS1 - Technical Solution Delivery	Control system fails to perform to specification	Specification outlined at design stage not met when test and trials carried out	System incompatibilities and unsatisfactory trial results	Open	Suppliers	2	3	3	6	Project Manager	The control system will be subject to performance testing using benchmarking or simulations under various operating conditions. Control system requirements to be defined at design stage and suitable control system chosen for the purpose of the trials. Service Level Agreements (SLA's) to be agreed for control system solution.
9	WS1 - Technical Solution Delivery	Resource interoperability	Using DER's for voltage stability control is untested in the UK and the availability of resources when called upon is critical. There must exist a sufficient information exchange between the control system and the DER's so that resources can be called upon in a timely manner	Lack of comms path or interoperability issues between the control system and the DER's may lead to delayed initiation of response and reduced ability of the control system	Open	NGET / UKPN	4	2	3	12	Working Group	Agree common standards for all controllable components through standard interface protocols which will be agreed upon by all controllable resources. Plan demonstration without critical requirement for communication path to all response providers.

10	WS2 - Commercial	DER under-recruitment	Lack of interest from DER's	Trials would not be able to proceed and project may need to be cancelled	Open	NGET / UKPN	3	3	2	9	Working Group	Early and continuous engagement. Customer feedback from the engagement sessions helping shape the commercial and technical designs. Commercial contingency budgeted for.
11	WS2 - Commercial	Provision of services by DERs to National Grid via UK Power Networks	Volume & price risk created by need to estimate sensitivity of each DER to the transmission constraint it is being asked to alleviate	Potential net revenues or losses as a result; stakeholders' exposure	Open	NGET / UKPN	2	3	2	6	Project Manager	Contingency fund in place to allow these risks to be absorbed. Agreed trials approach to mitigate impact. Learning will be fed to affect any regulatory changes required for the rollout.

Definitions

Likelihood	
1	L
2	M
3	M
4	H
5	H

Impact	
1	L
2	M
3	M
4	H
5	H

Score	RAG
1 - 6	
7 - 14	
15 - 25	

Likelihood

Impact	1	2	3	4	5
1	1	2	3	4	5
2	2	4	6	8	10
3	3	6	9	12	15
4	4	8	12	16	20
5	5	10	15	20	25

Control Opinion

Not Effective	Key controls have not been established or are deemed to be ineffective. Action plans to rectify the fundamental weakness have still to be fully implemented
Partially Effective	Key controls are in place but have either not been subject to suitable assurance activity or testing reveals that some control improvements, not deemed to be fundamental, are required
Effective	Key controls are in place, are tested periodically as appropriate and are deemed satisfactory. This testing includes independent challenge where the risk is deemed significant (e.g. from NG Audit or another independent assurance provider)

Reputation Impact Ratings

Score	Description	Definition
1	Internal	Internal - minor impact on stakeholders within NGT Group
2	Intra-Group	Internal - major impact on stakeholders within NGT Group
3	Local third party	External - impact on local stakeholders
4	National	External - impact on national stakeholders
5	International	External - impact on international stakeholders

Financial Impact Ratings

Score	£m
1	0 to 5
2	5 to 10
3	10 to 30
4	30 to 50
5	50+

Likelihood Impact Ratings

Score	Description	Frequency of Occurrence	Probability of Occurrence
1	Remote	< Once in 20 years	< 10% chance
2	Less Likely	< Once in 15 years	> 10% and < 40% chance
3	Equally Likely as Unlikely	< Once in 10 years	> 40% and < 60% chance
4	More Likely	< Once in 5 years	> 60% and < 90% chance
5	Almost Certain	One or more a year	> 90% chance

Appendix 6 Technical Description

A6.1 Contents

- Background – Voltage Stability
- Challenges
- DERs: the new resource
- TDI 2.0 Services
- Commercial Framework
- Trial methodology

A6.2 Background – Voltage Stability

The System Operator (SO) is required to maintain the transmission system within normal safe operational limits. Using a wide range of operational measures, the SO ensures that voltage is kept within acceptable stability and compliance margins and that energy in the system does not exceed equipment ratings. One of the main technical conditions needed to be maintained in the system is voltage stability throughout the network.

In general terms, a voltage instability phenomenon, as detailed in the report commissioned by this project and performed by Moeller & Poeller Engineering (Moeller & Poeller, 2016), exhibits a progressive and uncontrollable voltage drop at one or more substations after a disturbance or abnormal operating condition occurs. Instability can develop within a few seconds (short-term voltage stability) if a sudden large disturbance takes place, for example the tripping of a line or the loss of reactive support. This phenomenon is particularly observed when there are long corridors of circuits connecting generation and load centres which in turn result in high reactive power losses and considerable voltage drop.

Unlike active power, reactive power is less able to be supplied via long distances as the losses occurred during the transmission might affect the operation of the network as described above. Therefore, the general practice for supplying reactive power compensation is to install local compensation in the areas of the network that requires it. Voltage instability is essentially a phenomenon with local implications, that if accompanied with a succession of events may result in an incident with a wide system impact called 'voltage collapse', which, depending on protection relay operation, control device operation, and control room actions, could result in a partial or total system blackout.

Voltage stability assessments are performed via Power – Voltage (P-V) curves which are diagrams that represent the voltage sensitivity, in a specific busbar, with respect to the variation of the loading or power transfer levels. P-V curves are a tool to assess how much active power can be transferred in a system (maximum loadability) before it reaches low voltage points that may lead to voltage collapse.

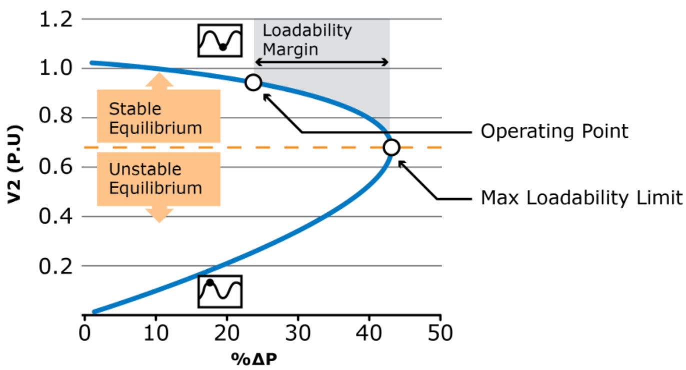


Figure A6.1 P-V curve (Moeller & Poeller, 2016)

When applying the P-V curve methodology, one of the main aims is to calculate the "loadability margin" (see Figure A6.1) which is an index that quantifies the proximity of the current operating point to the maximum loadability limit.

A6.2.1 Voltage and Reactive power control from DERs

Traditionally, DER has been operated at unity power factor as this is the simplest mode of operation, unless a different set-point is instructed by the Distribution Network Owner. In some cases, where the additional active power injection from the DG causes a voltage rise, a leading power factor can be chosen to limit the voltage rise to acceptable levels.

The normal approach for achieving voltage/reactive power control is for the DER to use a type of central controller which measures the voltage at the point of connection. The controller then automatically adjusts the reactive power output of converters and/or any additional reactive compensation equipment in order to achieve the required reactive power at the point of connection. This control loop typically operates in relatively fast (within 100ms) to achieve the specific grid code requirements.

Voltage (droop) control

In most cases the DER will be small, compared to the network it is connected to. Therefore, if voltage control is required, it is considered inappropriate to only take into account the voltage at their point of connection to be controlled to a set target value. If this type of control logic is set up, it would normally result in the DER operating at full reactive power output (either absorbing or producing) for the majority of time as they will not have enough reactive capacity to solely control the voltage to a set target. Instead it is typical to use a combined control logic which includes the point of connection voltage target as well as a reactive power slope, otherwise known as voltage droop control. An example of this approach is as shown in Figure A6.2 for a generator with 0.95 power factor leading and lagging capability. In this example there is a target of 1pu and a slope of 4%. Therefore, if the point of connection voltage is at 1pu then the DER will operate at unity power factor with 0 MVAr output at the point of connection. If the point of connection voltage drops to 0.96pu, a 4% drop from the target, then the DER will produce reactive power equivalent to 0.95 power factor (calculated based on rated MW). Conversely, if the point of connection voltage increases to 1.04 then the DER will absorb reactive power equivalent to 0.95 power factor. The system operator can adjust the target and slope to achieve different reactive power levels in response to voltage changes, although only the target is adjusted in operational timescales.

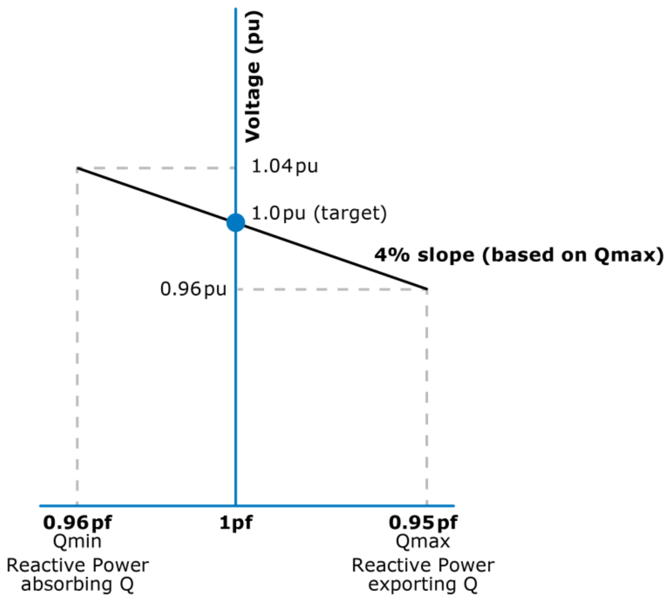


Figure A6.2 Voltage droop/slope approach in DERs (Moeller & Poeller, 2016)

A6.3 Challenges

The 400kV transmission corridor of the South East of England is influenced by the presence of large DER, transmission connected generators and interconnectors to the continent. NGET in their role of SO needs to manage the voltage and thermal limitations for certain network conditions, whilst still being able to transfer energy to the country's load centres. As discussed in Section 2 of this document, NGET have identified three main constraints that can occur over different generation and load conditions and during normal operation or fault conditions.

A6.3.1 Dynamic Voltage Stability

During certain fault conditions of the system, the voltage across the network might drop to unacceptable levels. The most prominent of these faults is a double circuit fault on the Kemsley-Canterbury circuits which leads the system to have only one route to transfer the electricity away from the area. Given that the western route is a long radial line and the significant amount of power that would need to be transferred at the time of the fault, the electrical behaviour of the circuit itself (including losses) will lead to a rapid voltage drop across the network seconds after the fault. This voltage drop is particularly observed in Ninfield GSP where it could potentially fall to 0.95pu. While this is not at the voltage stability limit, this voltage is at the planning limit as specified by National Grid in (National Grid, December 2014) and illustrated graphically in Figure A6.3.

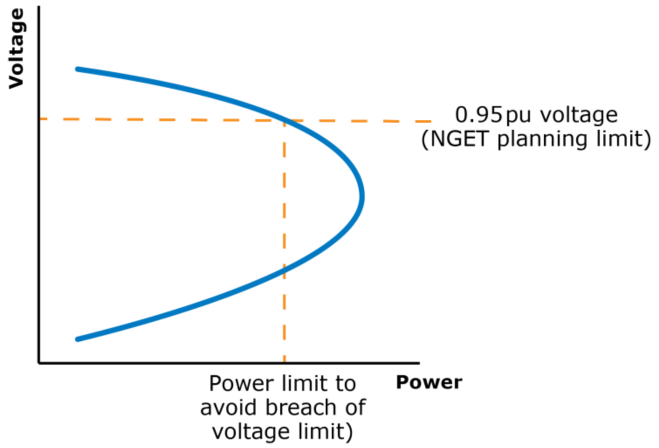


Figure A6.3 Example of P-V curve used by NGET (Moeller & Poeller, 2016)

If the voltage drop is not contained in time, this could lead to a voltage collapse and ultimately a 'blackout' of the network. It is for this reason that NGET has set a limit to the amount of generation that can be connected to the South East network.

Voltages across the electrical system are influenced and managed by the injection or absorption of reactive power. There are many options available to mitigate a voltage stability issue and allow more generation to connect in the southern corridor. However, many are impractical, would take a significant amount of time, or are prohibitively costly to realise. A potential list is shown below:

- Limit the active power in the transmission network
- Increase load in the area if load is available
- Limit generation at times of high outputs
- Reinforce the transmission system
- Series compensation
- Install reactive compensation: which can include using reactive compensation from DERs in the system.

The currently available reactive compensation in the transmission system will not be enough to contain the voltage drop as the 'real' power being supplied to the system increases. Therefore, NGET in their business as usual operations has plans to spend £120m on new reactive compensation but there is the risk that the new schemes will not be online in time.

A6.3.2 High Voltage

The low voltage (dynamic stability) issue could arise following a fault on the 400kV system. However, there is also a case where high voltage in the transmission system occurs in normal operation.

Changes in consumer demand profiles, the evolution to more undergrounded distribution networks and the growth of DERs on the distribution network, have given rise to a change in the reactive requirements of the system which have an impact on the voltage profiles of the system. These changes in system voltage profiles in particular during periods of minimum demand have been significant in recent years, introducing both planning and operational challenges for the SO. High voltage excursions, which can be seen during minimum demand periods, have been increasing in frequency, and operationally high voltage management has evolved from being a summer challenge to being a year-round issue.

Contrary to low voltage events on the transmission network which can be experienced by the consumers connected to the distribution system, high voltages are mostly confined and seen by transmission network and do not directly affect consumers. This is due to the fact that distribution network transformer's tap changer control acts to counteract these excursions.

To address high voltage problems on the transmission network, the system operator has employed a variety of operational and investment solutions including switching out transmission circuits, generation curtailment and the installation of new reactive compensation equipment.

A6.3.3 Thermal constraints

Besides the challenge faced by the SO to keep the voltage within the statutory limits at all times, it also faces significant issues to maintain the electricity flowing through the equipment within the equipment ratings. Under outage conditions when a circuit is de-energised for maintenance, network capacity on the South East is insufficient to permit full generation output as the SO needs to ensure that the network is still capable of sustaining another fault without violating any voltage or loading constraints. This leads to operational curtailment of the interconnectors and generators to prevent any loading violations.

The described constraints and challenges in the transmission network occur in different timescales and will need a suite of solutions that can address one of them without interfering with another.

Constraint	Effect seen	Response time needed
Dynamic Voltage Stability	Post-Fault	1-5 sec
High Voltage	Pre-Fault	Sec, mins, hrs
Thermal	Post-Fault	mins

A6.4 DERs: the new resource

As highlighted in Section 2, DG in the South East connected in UKPN's South East network has grown significantly in the past years. There is also a great level of interest in energy storage with over 3GW of connection enquiries across the SPN region and 120MW of accepted offers for sites on the South Coast.

DERs which encompass both generation and storage have a proven capability to supply reactive services on top of their business as usual mode. Importantly, DERs are extremely keen to participate more actively on the network and seek additional revenue streams. During this project DERs connected in 132kV and 33kV in the South East were approached with the concept of them participating in ancillary services for the system and there was significant response with at least 7 companies (including aggregators) confirming, either verbally or written, support for the concept.

The challenges faced by the distribution and transmission networks need to be addressed by a combination of reactive compensation and active power. DERs have the potential to change dynamically to produce or absorb reactive power when required and change their active power when instructed. The time of the response will rely heavily on the technology installed in each DER, but in some cases can be deployed in a matter of seconds using voltage droop control described earlier.

During the initial assessment of this project, Moeller and Poeller was commissioned was commissioned to validate the amount of MVArs that can be extracted from 132kV and 33kV connected DERs in the distribution system assuming that they all have the capability to change their reactive power output. The study concluded that up to 121 MVAr of producing and 226 MVAr of absorbing reactive power can be accessed from the DERs currently connected in the South East UKPN network. Furthermore, this value increases when Shoreham Power Plant (who already participates in the Balancing Mechanism), is also used for reactive services. The new response, including Shoreham, can be up to 476 MVAr of producing and 235 MVAr of absorbing reactive power. These results support the concept that there are distributed resources in the DNO network which can have a beneficial influence on system constraints.

A6.5 TDI 2.0 Services

TDI 2.0 seeks to provide NGET access to flexible distribution-connected resources to provide it with additional tools for managing transmission constraints. The project will use system in which DERs will be able to offer dynamic reactive power services to NGET and active power reduction to both UKPN and NGET to resolve distribution constraints and offer flexibility upstream to the SO to manage transmission constraints.

These services can be complemented by AVC control actions and voltage target reductions taken on distribution network assets and GSPs to maximise the response seen on the transmission network.

TDI 2.0 proposes three services to address these constraints; two dynamic reactive power services and an active power reduction service:

	Service Name	Brief Description	Constraint Addressed
Dynamic reactive power services	Instructed Reactive Compensation	NG to instruct the service to decrease voltage on the transmission network via reducing the voltage droop targets of DERs.	High voltage
	Dynamic Voltage Control (DVCS)	Triggered by network conditions (low voltage).	Dynamic voltage stability
	Active Power Management	Manages active power (optimised re-dispatch) for addressing distribution constraints and offering flexibility to the SO	Thermal constraints

A6.6 Commercial Framework

This section provides an overview of the commercial framework that would be put in place to deliver the services described above. The trial is running in parallel to NGET usual arrangements for securing the South East against voltage security and control to ensure that the transmission system is not jeopardised by unproven services. The DER services contracted for the TDI 2.0 trials will be funded from the TDI 2.0 budget.

As described in Section 2, NGET has multiple routes by which it can access DERs, including direct contracting and contracting with aggregators. The framework below focuses on the additional procurement of services via UKPN. Via this route, DERs contract with UKPN, committing to provide reactive and active services. UKPN then holds matching contracts with NGET, thereby giving NGET access to the DER flexibility.

A6.6.1 Tendering and bidding framework

Whilst there are a number of similarities between the commercial service design for active and reactive services, there are also significant differences. They are therefore described separately below.

Reactive power services

Summary: reactive power services take the form of competitively-tendered availability and utilisation prices tendered for in advance of delivery.

Utilisation bids

The short run operating cost of DERs providing the reactive power service is small as long as there is no need to forego active power export to create the reactive power capability. With Dynamic Voltage Control capability, DERs would have control over their reactive power output independently of their active power output. The utilisation payment is therefore expected to be relatively small, but it would be up to the DERs to choose the level of utilisation payment to bid at.

Availability bids

The bulk of the cost to the DER associated with the provision of reactive power services is the capital expenditure on the power electronics and control systems required to be technically capable. In order to encourage the provision of this service for the trails revenues must justify the expenditure on the equipment. To this end, the proposed contracting framework includes an availability payment (expressed in £/MVAr/h). This would allow DERs to offer availability, providing them with the financial certainty required to invest in the necessary equipment.

Active power services

Summary: active power curtailment is driven by competitive bids from DERs, which should be sufficient to require efficient investment.

Utilisation bids

The majority of the cost of providing an active power curtailment service for generating DERs is foregone expected revenue, a large portion of which for renewable DERs is lost subsidy. This opportunity cost can vary over time due to factors such as wholesale electricity prices, network use of service charging windows, and the provision of balancing services. An operational framework of short-term DER bids will be used to ensure cost effective procurement of active power curtailment.

A6.6.2 Settlement

The TDI solution will be able to track the tendered positions and the utilisation of each of the DER assets, and will therefore be able to collate and manage the data required to carry out settlement. We are, however, exploring the option of linking this system to a third party settlement system, which would manage settlement, payments and any collateral posting that was deemed necessary for managing commercial risks.

Trial methodology

TDI 2.0 will employ a trial approach which will seek to demonstrate the effectiveness of dynamic reactive response by means of testing against different use cases and their respective benefit accounting. The trial is designed to be implemented such that lessons learnt and results from each stage can be incorporated into the method. Results can then be used to determine if the solution should be deployed in other distribution networks with similar constraints.

The use cases to be used during the trial stages have been defined so that they demonstrate the main hypotheses of the project's methods. The hypotheses are summarised as follows:

Method	Hypothesis
Provide reactive and active power services from DERs to alleviate transmission constraints without undermining DNO network	The solution provides data, control flows and exchanges between DER-DNO-SO. The solution is effective in both service delivery and the expected impact on the network(s). DERs have the required capabilities to deliver the services
Deliver a sustainable commercial solution	The solution provides a whole system constraint management approach that is relevant and addresses future market scenarios and reduces consumer costs
Provide a solution that is attractive and open to existing and new participants	The solution aligns all participants to this market structure The market is accessible and attractive to new participants
Create an efficient coordination framework across SO and DNO	The solution addresses conflicts with other services. Provides a back to back integrated approach to constraint management in both SO and DNO starting from investment planning, operational planning and real-time.

Five main use cases have been identified from these hypotheses. They will be implemented during each stage of the trial with the relevant learning outcomes and success criteria's assessed before continuing with the next stage.

A6.6.3 Use Case 1: Technical delivery of services

This use case will focus on the complete (top to bottom) response of the reactive power services procured by NGET and delivered by the DERs through UKPN. It will fine-tune the capabilities of the ICT control solution to estimate the response at a GSP level as well as the capacity of the DERs to be able to provide the service.

Learning Outcomes	Measurements	Success
Ability of the solution to accurately estimate the response at GSP level. (Dynamic and steady-state)	% error of calculated response and actual response per GSP % error of calculated effectiveness of DER and actual effectiveness	+/- 5%
Capacity of the DER to provide a combination of reactive and active power services simultaneously	% error between MVArs and MW planned (contracted) and produced	+/- 5%
Time of solution services response in line with NGET requirements	% difference in planned and dispatched time	+/- 5%
Time response in sending at a revised voltage target to DG	% difference in planned and dispatched time	+/- 5%
Understand how different operational environments affect the DER service response	If error of actual response greater than 5%, create cause-effect analysis to understand cause	N/A

A6.6.4 Use Case 2: Enhanced methods to maximise response

Once the learning outcomes of use case 1 have been accomplished, use case 2 will seek to maximise the response from the solution. It will do so by exploring a novel approach to automatic voltage control and voltage target changes at Grid (132kV to 33kV) and GSP transformer to maximise the response that DERs can deliver.

Learning Outcomes	Measurements	Success
Understanding of enhanced AVC controls to maximise service response at Grid and GSP	% change in MVAr response compared with no enhanced method used	+ Increase in MVAr Cost effectiveness vs BAU

A6.6.5 Use Case 3: Commercial framework validation

This use case will be used to engage with potential service providers and provide an insight into the value of the service to the SO, the cost of delivery to DERs, and the length of contracts required for the services.

Learning Outcomes	Measurements	Success
How the market will be designed such that it can benefit all parties and be attractive to new and existing participants	% change in TNUoS / Planned Capital Spend (NGET)	Decrease in TNUos / CAPEx
	% change in BSUoS (NGET)	Decrease in BSUoS
	% Change in additional capacity (UKPN)	Increase in distribution capacity
	Internal Rate of Return from DERs (IRR)	On target / exceed expectations
Understand how the commercial framework will evolve in the project	N/A	N/A

A6.6.6 Use Case 4: Market effectiveness

Use case 3 provides insight to how the proposed commercial framework is delivering value for money to the consumers. However, there is a risk that even though the market delivers the agreed benefits, that this commercial framework is not attractive enough to recruit new participants. This use cases analyses the willingness of new participants (either already connected to the DNO network or new connection application) to participate in the market.

Learning Outcomes	Measurements	Success
Determines if the market is attractive enough for new participants and reduces costs for consumers	Customer Survey	Increase in market interest
	Technology Diversity	Representation of different technologies

A6.6.7 Use Case 5: Coordination of services

One of the goals of the TDI 2.0 project is to make sure that the solution results in a coordinated approach to constraint management between NGET and DNOs. This use case will create a framework of roles, process and proposed business changes to integrate the solution into business as usual. It will also address interactivity with other commercial frameworks and operational services options available to use by NGET or DNOs.

Learning Outcomes	Measurements	Success
Determines if other explored services can be deployed simultaneously and their effect on the effectiveness of the original TDI 2.0 service.	% change in MVAr response compared with no other service used	On target / exceed expectations
Understand which organizational/process/business changes are needed to align the services into BAU of the SO and DNO	New roles and responsibilities laid out in the process	N/A

Detailed use case example			
Description	UKPN are to provide to National Grid with the availability and capability of services at each Grid Supply Point in the next period.	Trigger	DER on the distribution network will automatically send UKPN current and forecast information, which UKPN will automatically cumulate aggregate and publish to National Grid.
Primary Actor/s	Control Room (UKPN, National Grid, Aggregators and DERs)	Secondary Actor/s	IT support, Commercial
Pre Conditions	DERs have a commercial contract DERs can provide relevant information UKPN can receive DER information UKPN can produce information at GSP & publish to National Grid National Grid can send desired GSP state to UKPN UKPN can translate GSP desire state to individual DER	Post Conditions	National Grid can view the availability and capability of services at each Grid Supply Point. This view will show both what is available and capable in the current window

Description of Trials	
Check Communication and information flow (between NG, UKPN, Aggregators and DER)	• Check correct information flow i.e. Send/Received checks between parties. • Check correct intervals eg. Every 15 minutes
Check Accuracy of Calculation of Reactive Equivalent at GSP	• Capture calculated GSP Equivalent Reactive Capability at a moment in time • Capture actual DER reactive capabilities/availabilities and DNO network conditions at those moments • Simulate the system with load flow calculations • Do the two agree?
Verification of DER reactive capability against contract values	• Instruct DG to operate at extremes of reactive capability for appropriate period 15min-1hour? • Does measurement data support contractual capability? To be considered: • Is this a Self test or witnessed? • Recording rate at 1s/10s samples? • Assessment by NG or UKPN? • Do DGs in trial have to have monitors connected?

Verify dynamic capability of DG against specification/contract	Individual DG Test (method based on Grid Code OC5.A.3) by 1. change of voltage reference 2. tapping an upstream transformer • Does steady state change follow calculated droop? • Does response occur in time period in contract? • Does measurement data support contractual capability? To be considered • Self-test for smaller providers, witness larger? • Assessment by DNO or NG? • Do DGs in trial have to have monitors connected?
Trial Real Time Steady response at GSP and at DER by Monitoring	• Collect time stamped Voltage & reactive flow on Super Grid Transformers from NG substation • Collect time stamped Voltage & reactive output from DG providers • Is performance as predicted? To be considered • Sampling rate? Assessment by DNO or NG?
Grid Supply Point Test of DG Dynamic Response	Possible ways to induce voltage change • Switch supergrid circuits? • Rapid HVDC direction changes? • Tap SGTs at GSP to vary Distribution voltages • Is response at GSP measureable? • Is resultant change in DG reactive as predicted by contract? To be considered • Monitoring on Providers/GSP during trial? • Assessment by DNO or NG?
Trial Real Time Dynamic Response by Monitoring	• Real time monitoring 3 months • Maybe Gen Losses/circuit trips • Do transient voltage changes at GSP result in expected MVAR changes? • Is there evidence of providers delivering for changes? • Monitoring on providers /GSP during trial? • Do payments under mechanism correctly reflect MVAR delivery? • Do payments reflect value to DNO and/or NG?

A6.8 References

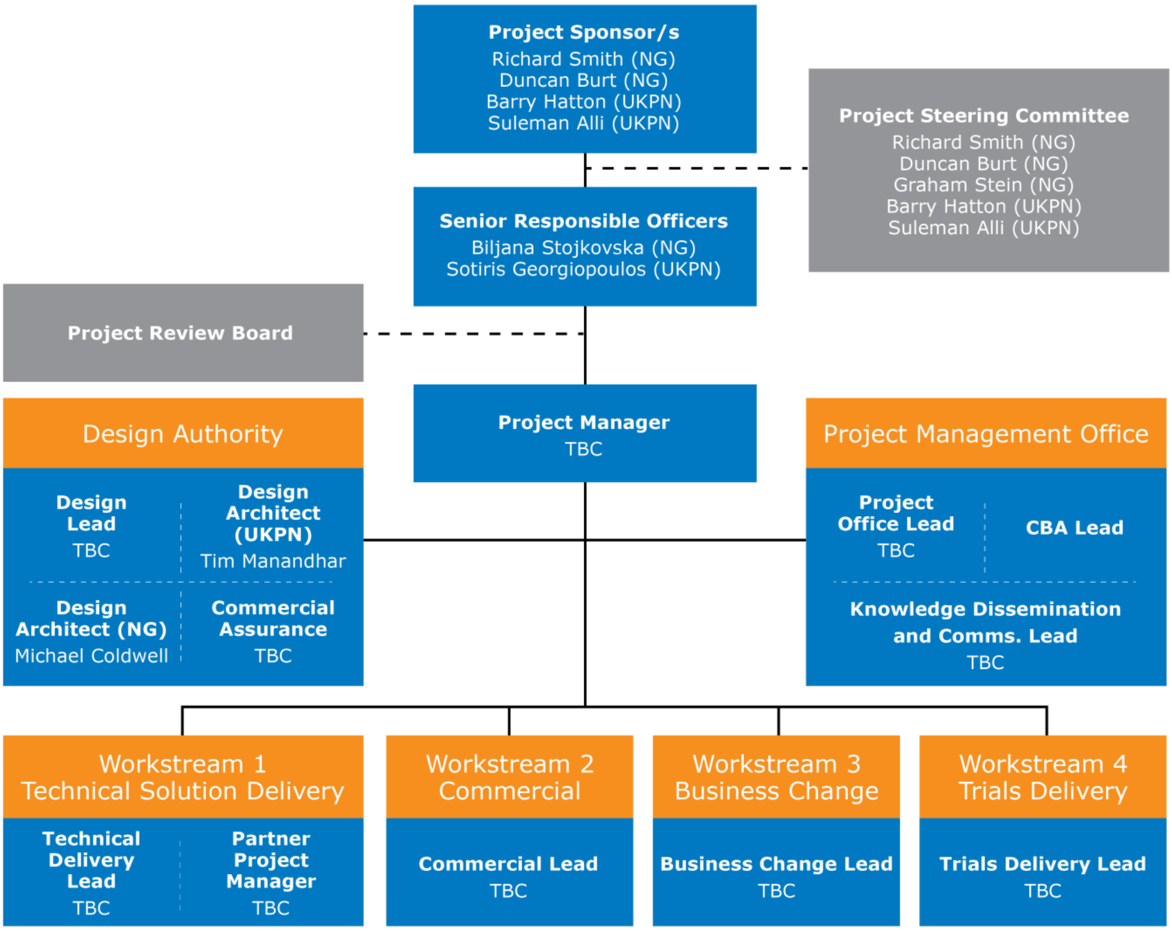
Mayor of London. (2011). *Delivering London's Energy Future*. London.

Moeller & Poeller. (2016). Power system simulation studies for National Grid Network Innovation Smart Grid Project (TDI 2.0). Moeller & Poeller - Available upon request.

National Grid. (2015). *Electricity Ten Year Statement.* Warwick.

National Grid. (December 2014). National Electricity Transmission System Security and Quality of Supply Standard, Version 2.3. Warwick: National Grid.

Appendix 7 Project Organisation



Appendix 8 Project Partners

Organisation	National Grid (Project Partner)
Organisation type / description	System Operator
Contractual relationship	Under negotiation: National Grid and UK Power Networks intend to sign a bi-lateral agreement.
Project role summary	National Grid is jointly leading the project with UK Power Networks, including active involvement in each of the project workstreams with several of its team fulfilling workstream lead roles.
What does the partner bring to the project?	Working knowledge and experience of dynamic voltage problem in transmission system in the South East part of the network.
Funding	National Grid will contribute £0.75m to the project.
External collaborator benefits from the project	The project will improve the flow of information between National Grid and UK Power Networks resulting in further collaboration opportunities and improving the reliability of the network.

Organisation	UK Power Networks (Project Partner)
Organisation type / description	Distribution Network Operator
Contractual relationship	Under negotiation: UK Power Networks and National Grid intend to sign a bi-lateral agreement.
Project role summary	UK Power Networks is jointly leading the project with National Grid, including active involvement in each of the project workstreams with several of its team fulfilling workstream lead roles.
What does the partner bring to the project?	Working knowledge and experience of the constraints on the South East distribution system.

Funding	UK Power Networks will contribute £0.75m to the project.
External collaborator benefits from the project	The project will improve the flow of information between National Grid and UK Power Networks resulting in further collaboration opportunities and improving the reliability of the network.

Organisation	Technical Partner (TBC)
Organisation type / description	Hardware / Software Supplier
Contractual relationship	New relationship, selected through a competitive procurement process to provide control system hardware and software.
Project role summary	The supply and delivery of control system which will be the interface between transmission and distribution systems, which will instruct DER's at distribution level to operate in the required control mode to alleviate dynamic low voltage problem during local outage.
What does the partner bring to the project?	Selected technical partner will be chosen based on innovative approach, technical experience & expertise, and competitive price.
Funding	Technical partner would be expected to provide in-kind contribution of an amount TBC.
External collaborator benefits from the project	Selected technical partner will benefit from exposure to a new market. They will also be first choice for post-project support i.e. when it becomes business as usual.

Organisation	Aggregator(s) (TBC)
Organisation type / description	Manage individual to several DERs.
Contractual relationship	New relationship, RFI process carried out, followed by joint engagement sessions held by National Grid and UK Power Networks.

Project role summary	Once contract negotiations have been completed, and contract signed, Aggregator(s) will be involved in the trial phase of the project, where their managed DER(s) will be required to operate between different control modes as requested by the control system.
What does the partner bring to the project?	Aggregator managed DERs will provide the solution, through reactive and active power injection onto the distribution and transmission networks, helping to relieve network constraints at transmission level, and allowing for the connection of more generation at distribution level.
Funding	N/A
External collaborator benefits from the project	Payment for use of their service.

Organisation	Customer(s) (TBC)
Organisation type / description	Manage individual to several DER's.
Contractual relationship	New relationship, RFI process carried out, followed by joint engagement sessions held by National Grid and UK Power Networks.
Project role summary	Once contract negotiations have been completed, and contract signed, Customer(s) will be involved in the trial phase of the project, where their managed DER(s) will be required to operate between different control modes as requested by the control system.
What does the partner bring to the project?	Customer managed DERs will provide the solution, through reactive and active power injection onto the distribution and transmission networks, helping to relieve network constraints at transmission level, and allowing for the connection of more generation at distribution level.

Funding	N/A
External collaborator benefits from the project	Payment for use of their service.

Organisation	Academic (TBC)
Organisation type / description	Research & analysis group
Contractual relationship	New relationship, pending further conversations to appropriately match research interests with project objectives
Project role summary	Research and analysis through application of robust academic methods, trial of novel ideas and techniques, and knowledge dissemination
What does the partner bring to the project?	Research and analysis to aid in achieving project objectives
Funding	N/A
External collaborator benefits from the project	Payment for use of their service.

Appendix 9 Work Stream Descriptions

A9.1 Project Management Office (PMO)

The aim of the Project Management Office (PMO) is to support project sponsors and managers in the successful delivery of the TDI 2.0 Project through consistent application of project management practices and the provision of consolidated project information to assist key decision-making.

The scope of the PMO includes:

- Managing the project plan, track usage of project resources, budget control, quality assurance and ensure project processes are followed
- Update and maintain the Costs Benefits Analysis (CBA) to stakeholders at various stages if benefits are being delivered
- Effectively disseminate the learning gained from the TDI 2.0 project to the key stakeholders
- Ensure the provision of appropriate and reliable information to stakeholders regarding the project, using appropriate methods to maximise the effectiveness of dissemination activities.

PMO Processes	Principal Objective	Deliverables
Resource & Budget Mgt.	To provide project-level accounts of estimated and actual project resource and cost. To ensure the utilisation of internal and external resources is managed effectively and in accordance with project priorities	Project Budget and Forecasts
Project Reporting	To ensure all stakeholders receive accurate and current information on the status and performance of each project including schedule, milestones, budget, quality and risk	Weekly / Monthly Reports OFGEM Reports
Scope/Change Mgt.	To facilitate scope management of the projects using a controlled process that ensures the impact (i.e. budget, quality, deliverable) of changes are clearly assessed and understood	Project Change Request Log
Project Planning	To maintain a high-level plan of all project activities across the project	Project Plan / Milestones
Risk Management	To ensure all risks are identified and managed through realistic and effective strategies throughout the full lifecycle of the project	Project Risk Log
Issue Management	To ensure all issues that may impact the project are identified and resolved within the required time frames	Project Issue Log
Document Management	To maintain a central repository of key project documentation	Version Control
Quality Assurance	To review the quality of project processes and deliverables against set criteria	Project Quality Assurance Log
New Joiners / Leavers	To ensure that new joiners are effectively and rapidly assimilated into the project with the appropriate level of support. Ensure that project leavers are managed correctly	On Boarding New Joiners / Leavers

A9.2 Project Design Authority (PDA)

The PDA will be responsible for ensuring all aspects of commercial, technical design, architecture, and specifications for the project. The PDA also ensures that end to end technical design enables the project to deliver to the requirements outlined in the TDI 2.0 proposal.

The PDA will review all detailed designs and plans produced by the individual work streams to ensure compliance with specifications. They will also provide advice and guidance to the partners and work streams involved in designing the solutions, but will be independent of these delivery functions to ensure impartiality and assurance.

The Project Design Authority will be made up of a number of key roles:

- Delivery Assurance – IT Delivery experience to ensure the plans are deliverable and robust
- ICT Assurance – Operational IT / Hardware expert who ensures solution will work in the field
- IT Assurance – IT Architect who ensures the solution will integrate into BAU systems
- Commercial Assurance – Ensures that design delivers the new commercial frameworks outlined as part of the project
- Senior Users
  - Control room
  - Outage planning
  - Infrastructure planning
- External Subject Matter Expert (fulfilled by Project Partner).

These roles will report to the Programme Manager but will have a dotted line relationship with the Solution Owner (Business role) to ensure accurate definition and, once defined, protection of the scope and timeline.

A9.3 Work Stream 1: Technical Solution Delivery

The Technical Solution Delivery work stream will comprise of the following:

- Architecture
- Functionality
- Delivery & Integration (D&I)
- Testing

A9.3.1 Architecture

Responsible for the development of designs and documentation across all systems, communications, and hardware. This will also lead on the development of the business requirements and be heavily involved with vendor selection, the PDA and work with partners to develop the delivery approach (Agile v Waterfall etc.).

Architecture is responsible but not limited to designing and documenting the following:

- IT Systems
- Operational IT Systems
- Communications
- Security
- Infrastructure
- Data
- Integration and Interfaces etc.

Key Deliverables / Responsibilities	Description
Architecture Standards	Establish the overall technical architecture and standards for the programme
Partner/s Selection	Own the Partner/s selection process by creating the RFP and organising business participants
Business Requirements Specification	Collation of the business requirements (functional) to support the partner deliverable Functional Design Specification (FDS)
Design Workshops	Facilitate design workshops with the business and partner to achieve FDS signoff
Delivery Approach	Work with partners and project members to define and document the delivery approach – includes supporting the development of the project plan
Subject Matter Expert	Provide end-to-end oversight of the design of the TDI solution including integration to legacy systems and assist in resolving Risks and Issues that are escalated through the programme
PDA Member	Participate in the Project Design Authority, including documenting architectural decisions and delivery taking into consideration technical alternatives and constraints

Architecture will be involved in the programme through the Define and Design phases but will taper off during the Develop and Test phases as the solution is built and released. At which point Architectural services will be performed by the PDA or as and when required accessed via existing BAU functions.

A9.3.2 Functionality

Functionality will be staffed through BAU seconded roles and provided specialist Control Room, Outage Planning and Infrastructure Planning skills to ensure the solution is fit for purpose and outputs are communicated back into the business. Therefore, the primary role of Functionality will be to represent the Business Owner to make sure that the requirements for their area of the business are met and that the functional designs (user interfaces, applications etc.) are fit for business use.

They will also play an engagement role back into the business, co-ordinating the involvement of business representatives in project. Additionally, where further network modelling or technical investigations are required, Functionality will also provide those services.

Key Deliverables / Responsibilities	Description
Vendor/s Selection	Be part of the vendor selection process by having involvement in the development of the RFP and selection of partner/s
Business Requirements Specification	Input into and signoff the business requirements to support the partner deliverable Functional Design Specification (FDS)
Design Workshops	Participate in all design workshops
Subject Matter Expert	Provide specialist business knowledge and insight to inform designs and delivery and where required engage the business to find answers

Business Engagement	Setup regular sessions and present to the business project updates
Additional Services	As required provide further network modelling or technical investigations to support other work stream deliverables

The concept behind this team is to bring business subject matter experts into the project early and keep their presence through the life of the project. Therefore, through the Define and Design phases this team will taper off and shift into Testing to support a range of testing activities. Post-testing the same resources will be shifted as required into Trials or Operational Support to commence the process of embedding activities back into the business ahead of completion of the project.

A9.3.3 Delivery & Integration (D&I)

D&I are responsible for the technical delivery of the solution. Multiple businesses will be responsible for delivery therefore National Grid, UKPN and Partner/s will have their own D&I lead, responsible for managing their own teams to deliver the plan. At this stage the scope of the D&I includes but not limited to:

- IT Development
- Functional modifications
- Hardware installation
- Field based installations
- System integrations
- User / Permission settings etc.

Key Deliverables / Responsibilities	Description
Delivery Approach	Responsible for defining and documenting the delivery approach – includes supporting the development of the project plan
Delivery Plan	Develop and own the delivery plan, ensuring dependencies and risks are managed across different delivery teams

A9.3.4 Testing

Testing is responsible for how all project testing activities will be defined, planned and executed. They will define the strategy and document any deviations or specific test methodology that is not covered in the Master Test. It must ensure that appropriate levels of testing are recommended in line with the perceived level of risk for that project, and the scope is not limited to:

- All system, integration and interface testing across multiple delivery areas
- End to end testing of the whole solution, so this includes field hardware, customer interfaces and communications etc.

Key Deliverables / Responsibilities	Description
Test Objectives	Provide a concise summary of what testing aims to achieve. These objectives must be measurable and relevant to the project

Test Methodology	The test methodology details the approach or method to which the test management process is applied to a project
Test Approach	Test levels should provide an understanding of standard terminology used on all projects in UKPN (from testing to IS Ops). All the levels of testing relevant to the project should be included here and those not relevant should detail why it's excluded from the approach. Typical outputs include but not limited: • Test Tools & test Management tools • Test data Management • Non-functional testing Approach • Entry and Exit criteria • Test Schedule • Defect management process • Roles and responsibilities within testing • Management review process
Test Assurance	This will focus on how 3rd party testing has been conducted – Quality Assurance

As previously mentioned SMEs previously used as part of Functionality and will provide support during the Testing phase to further ensure the product meets business requirements.

A9.4 Work Stream 2: Commercial

The Commercial work stream will have responsibility to develop new contracts in line with the new commercial framework and sign up new customers. Once new customers are signed up the work stream will be responsible during the trial to ensure the flow of financials around between Customers, UKPN and National Grid remain in line with the contracts.

Key Deliverables / Responsibilities	Description
Develop Contracts	Develop new contracts for DER customers
Sign up Customers	Sign up new customers onto the new contracts ahead of the trials
Monitor Payments	Ensure the correct payments are made during the trial

A9.5. Work Stream 3: Business Change

The Business Change work stream is critical to the successful implementation of the TDI 2.0 Project and the ongoing success of National Grid, UKPN and our Customers. This work stream will be responsible for developing the overall Business Change strategy and implementing that strategy to ensure smooth transitions from Delivery into Trials into BAU and encompasses Business Readiness, Process Mapping, Communications, Organisational Changes and Training. Therefore, the scope of Business Change will include but not limited to:

- The project will identify and assess the changes associated with implementing the TDI 2.0 Project, the impacted groups within both businesses, any resulting changes to their roles and responsibilities, and any associated communications, engagement, training and/or business readiness activities needed to prepare them for the change;

- The project will engage with teams and individuals affected by the new solution to prepare them for implementation of the new system;
- The programme will identify any new processes that are necessitated by the way the new solution works and will lead the definition and documentation of these processes with input from the business units;
- The project will identify required changes to existing business policies, processes and procedures and will provide input to the business units to support them in making the required updates to these documents;
- The project will identify and highlight any changes in resource requirements in areas of the organisation that are affected by the new solution and work with the business units to define any associated changes in people's roles and responsibilities, providing input to assist the business units in making any required updates to Job Descriptions;
- The programme will provide appropriate training and/or knowledge transfer to users of the new solution to support them in performing their roles using the new system in both the interim and the Business as Usual periods;

Key Deliverables / Responsibilities	Description
Business Change Strategy and Plan	Overall strategy and approach for Business Change for the TDI 2.0 Project
Change Impact Analysis (CIA)	A Change Impact Analysis (CIA) will be carried out to identify impacted groups, the impacts to their roles, and any associated communications, engagement, training and business readiness activities needed to prepare them for the change to the new solution. The CIA will also identify the key impacted business processes and/or any new processes that need to be developed as a result of implementing the solution.
Organisation Impact Assessment (OIA)	Based on the outputs of the CIA, an Organisation Impact Assessment (OIA) will also be carried out, where the change impacts identified by the CIA are mapped to teams and roles in the business.
Stakeholder Mapping and Tracking	A Stakeholder Mapping will be created at the beginning of the project and updated following completion of the CIA, and at regular intervals during delivery of the project. Interventions will be planned in the Communications & Engagement Plan to help progress stakeholders through: Awareness; Understanding; Engagement; and Commitment as appropriate. It is important to note that not all stakeholder groups will need to reach 'Commitment' in order for the project to be successful.

Communications & Engagement Plan	The Communications & Engagement Plan will be driven by the Stakeholder Mapping and the output of the CIA and OIA. Communications and engagement will be targeted by group based on the degree of change impacting that group, when the change occurs, and the potential influence of the group on the success of the Project. Based on the characteristics of the project key principles for communications and engagement are: • All communications should reinforce the need to change and our commitment to doing so; • Communications will be tailored to stakeholder groups in terms of 'what it means for them' to make sure that when we communicate it is relevant and has value to the audience; • Since this is a long project, communications to the wider business will be limited to key milestones and events when people across the business will be impacted by programme activities (e.g. recruitment of the project team, End User training, system Go-Live) in order to avoid 'communications fatigue'; and • The programme will aim to show End Users the new system as early as possible
Business Readiness Checklist	The CIA will identify areas where the business will need to prepare to accommodate the new solution and create a Business Readiness Checklist of the required preparation activities for their area based on the output of the CIA. It is anticipated that the following activities will form part of the Business Readiness Checklists: • Updates to existing policies, processes and procedures • Implementation of new processes required by the solution • Opportunities for improvement to current ways of working that will be supported by / required for the new solution • Changes to reports and other management information that will be driven by the change to the new solution
Business Cutover Plan	The Business Change work stream is responsible for defining the activities that will be undertaken by the business during cutover period of the new solution – these will be incorporated into the overall programme Cutover Plan.
Training and Knowledge Transfer Strategy	A Training and Knowledge Transfer Strategy will be produced which explores, at a high level, the groups requiring training and sets out the proposed methods for delivering training. The Training and Knowledge Transfer Strategy will also provide a high level plan for training delivery and an estimate of the effort required to deliver the required training – as well as setting out the responsibilities between Partner/s, National Grid and UKPN for delivering the training materials and training sessions.

Training Needs Analysis (TNA)	A Training Needs Analysis (TNA) will be conducted following agreement of the overall Training and Knowledge Transfer Strategy. The TNA will identify detailed training requirements at the level of individual roles. The TNA will also identify where training needs can be more effectively delivered by Knowledge Transfer activities. The TNA will be based on the output of the OIA and take into account the changes identified to trainee's roles. The output of the TNA will be used to build a curriculum of training courses and other training interventions (such as Knowledge Transfer) and to plan out the number and timing of those courses and interventions.
Training Curriculum & Plan	A Training Curriculum will be produced with a set of proposed training courses and their mapping to individual roles. The Training Curriculum will be used to produce a plan for training delivery and enable scheduling of individuals onto training events.
Training Materials and Training Support Materials	Based on the Training Curriculum – and taking into account pre-existing Partner/s courses and materials – the set of Training Materials and Training Support Materials for the project will be created. Training Materials will be the materials used to present the subject matter to the End Users. These will be based wherever possible on existing Partner/s courses and materials. However, the materials will be enhanced to include the context of the use of the system at national Grid or UKPN in terms our policies, processes and procedures. The training materials will also be an important channel for communications and engagement
Training Environment	As part of the RFP process and Partner/s selection, dedicated training environments will be investigated. Ideally the partner/s will have an Operator Training System (OTS) which will allow trainees to perform simulated operations on a direct replica of the solution. The Business Change work stream will be responsible for preparing the OTS ahead of training sessions in order that appropriate data are available to enable training exercises to be completed.

A9.6 Work Stream 4: Trials Delivery

The Trials Delivery work stream will comprise of the following:

- Trials
- Operational Support

A9.6.1 Trials

The role of Trials is to deploy releases of the solution into operation and establish effective use of the solution in order to deliver value to all users. This includes ensuring that all elements of the solution have been rigorously tested and meet the defined criteria prior to go-live. In scope of Trials but not limited to:

- Ensuring all necessary field equipment is installed and ready to be used
- Ensuring all IT solutions have been tested and meet go-live requirements
- Regular engagement with customers to ensure they are fully ready to take part in the trial, both technically and commercially

Key Deliverables / Responsibilities	Description
Trials Approach	Develop and own the Trials Approach including the trial partner selection criteria and the schedule for when trial partners are to commence on the trial
Customer Engagement	Own the regular engagement with customers through structured forums to ensure all parties are made aware project progress
Trial Partner Readiness and On-Boarding	Ensure trial partners are fully prepared and aware of when they will be brought onto the trial
Hyper Care	Provide a heightened level of support in the initial stages, possibly at customer site, to ensure smooth go-live and operation
Field Deployment	Ensure field equipment is installed and tested

Whilst engagement with customers will begin early in the project, Trials will commence around the Develop / Test phases and continue through until early in the Trial phase. There Trials lead role will likely be performed by the Trials Project Manager with support staff to assist, most likely coming from Functionality.

A9.6.2 Operational Support

Operational Support will provide on-going support to customers and users as the project ramps down. This will be performed by project staff who have transitioned back into the business and by BAU staff who have been trained.

In scope of Operational Support but not limited to:

- IT support and fixes
- Field support and fixes
- On-going training
- On-boarding of future customers outside of this project

Key Deliverables / Responsibilities	Description
Support Model	So what areas of the business will provide support / what is the approach to providing support – new centralised function vs existing support structure
Documentation	Updating support documentation
On-Boarding new customers	Support new customers as they become part of the new operation
Field Deployment	Ensure field equipment is installed and tested

As mentioned earlier business people who were involved with Functionality may form part of the support team.

Appendix 10 Cost Benefit Analysis

A10.1 Today's model

The capacity of the Transmission Network in the South East of England is limited by a number of voltage constraints on the network. The constraints consist of high steady state voltages during periods of low demand, and a lack of dynamic voltage support following a network fault. These constraints result in constraining DER and interconnectors, preventing new DER connections and the need for further network reinforcements. In the Business as Usual (BaU) case significant operational and capital expenditure is required in order to alleviate these constraints.

During periods of low demand, the transmission lines in the South East become lightly loaded and produce excess VARs, resulting in high voltages that need to be managed. An increasing penetration of DER increases the likelihood of these conditions occurring due to the generation offsetting demand on the distribution network, therefore reducing the demand on the transmission network. The BaU approach is to constrain existing generation and the current operational costs for reactive compensation are in the range of £14m per annum. The constraint also triggers the need for further network reinforcement which is carried out by installing static reactive reactors. Shunt reactors are inductive components and therefore absorb the excess VARs produced when the network is lightly loaded.

During periods when interconnectors are in heavy use there is an increasing need for dynamic voltage support in order to prevent voltage collapse following a network fault. This constraint is limiting the connection of DER as new dynamic reactive power support is required to increase the available network capacity. The BaU case is to provide this reactive power support through the installation of Flexible AC Transmission System (FACTS) devices such as SVCs and STATCOMs. These units are capable of providing a dynamic response, as opposed to the static nature of shunt units, however these technologies are costlier to purchase and manage over their planned life. National Grid's dynamic voltage analysis in the South East area has revealed that for 1000MW of generation connection, a further 900 MVAr of dynamic reactive power support is required. Based on unit costs, this would be achieved at a cost of around £90m.

A10.2 TDI 2.0 Approach

The TDI 2.0 project seeks to mitigate the BaU costs by providing NGET with access to dynamic reactive services from DER. The Instructed Reactive Compensation service is designed to alleviate high voltage at steady state by reducing the voltage droop targets of DER on instruction, resulting in the absorption of VArs. This reduces the need to curtail generation and offsets the need for installing shunt reactors on the network. Through the Dynamic Voltage Control service, DERs are able to deliver dynamic reactive power support comparable to the service provided by FACTS devices. There is therefore the potential to make significant capital expenditure savings.

Instructed Reactive Compensation will address high voltage by setting voltage control target so DERs absorb reactive power when required. This reactive power absorption will help the SO to manage the voltage at the transmission level by complementing the already existing options with this service. This service is based on the DER's capability for automatic voltage control, working from the voltage at the point of connection but setting a low target. This is due to the fact that a high voltage excursion will not necessarily be seen on the distribution network.

A10.3 CBA approach

In order to produce a Cost Benefit Analysis (CBA) based on Sparkman Approach [1], a BaU and TDI 2.0 innovative case needs to be clearly defined. Without a scheme such as TDI 2.0 the result could be viewed in one of two ways:

- The options available to manage the constraint could be deemed economically unjustifiable, in which case the most likely outcome would be that the desired level of DER deployment would not be achievable
- The options available to manage the constraint could be implemented, with the cost of those constraint management options being incurred.

In the first situation, the benefit of TDI 2.0 would come in the form of increased DER deployment, which would presumably be dominated by renewable generation. In the second situation, the level of DER deployment is unchanged. The benefit of TDI 2.0 is the reduction in the cost of accommodating those levels of deployment within a constrained network.

For the purpose of this CBA the second example is assumed. The key differentiator between the Baseline (no TDI 2.0) and the TDI 2.0 case, therefore, is the cost of constraint management. Note that in reality it is expected that some combination of the two routes would be expected in a no-TDI 2.0 world, with lower levels of DER deployment and a higher constraint management cost.

A10.4 Today's model (Business as Usual) Approach

The costs of managing the constraints on the transmission network are primarily driven by the rate of deployment of DER. This rate has been forecasted by the UKPN Strategy and Regulation team, which is summarised in Figure A10.1, and culminates in an expected 3,720MW of new DER connections by 2050.

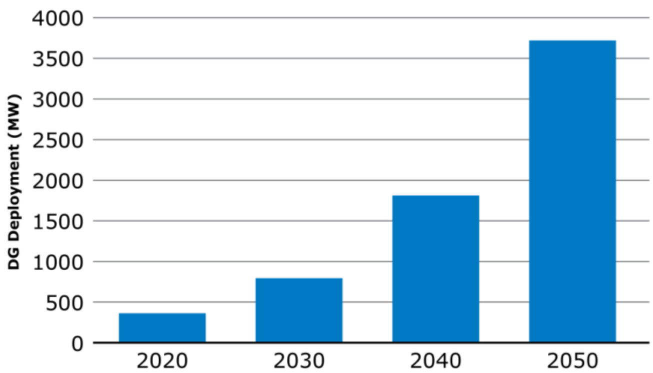


Figure A10.1 Assumed DER deployment profile

In order to mitigate the constraints associated with this additional DER, NGET would need to deploy increasing levels of Shunts, SVC and STATCOMs. We have assumed the following when estimating the rate at which these technologies are added, and the blend required:

- For every 1 GW of transmission capacity required, 900 MVAr is needed at transmission level
- The gap between the thermal and voltage stability limit is estimated to be:
  - Currently: 530 MW (thermal limit is 2 x 2780 MW, voltage stability limit 5030MW)
  - 2024 (After Dunganess is decommissioned): 1610 MW
  - 2040 (After Transmission circuit upgrades): 3210 MW
- New FACTS units are installed in equal ratios (balancing cost with capability)
- FACTS costs are estimated (based on ETYS average), for a 200 MVAr unit, to be
  - Shunt reactor: £8.6m (Transmission installed) or £5.0m[3] (Distribution installed)
  - SVC: £14.6m
  - STATCOM: £24.4m

[3] http://www.smarternetworks.org/Files/REACT_151111105142.pdf

For the Spackman approach the following input data were used:

- Weighted Average Cost of Capital (WACC):4.25%
- Annuity duration (years): 20
- Duration of pre-fault voltage control:160 h
- Duration of post-fault voltage control:11.69h

Under these assumptions, the expected capital expenditure (capex) on new FACTS units required to incorporate additional DERs is shown in Figure A10.2.

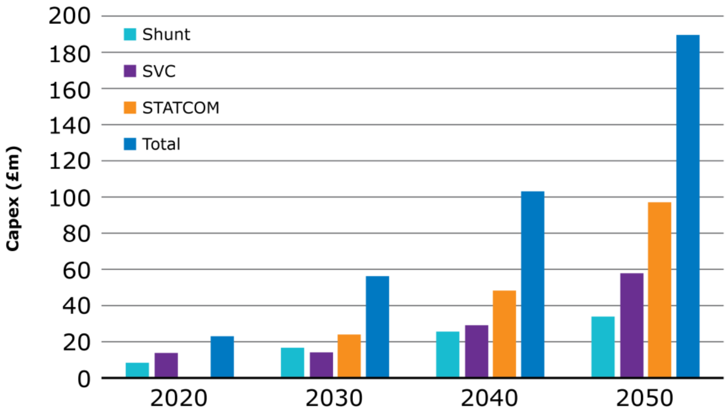


Figure A10.2 Capex profile under BaU scenario

A10.5 TDI 2.0 Innovative Approach - CBA assumptions

As covered previously, we assume that the DER deployment profile is unchanged from Figure A10.1 in the TDI 2.0 case. However, because NGET has access to DER services to manage the constraints exacerbated by DER, the need for investment on the Transmission network is reduced.

The extent to which this investment can be offset depends on a number of factors:

- The number of existing DER that can be brought under the ANM scheme, and are therefore able to contribute reactive and active power services
- The amount of reactive power that is made available, which will depend not only on the volume and type of DER connected, but whether they choose to enhance their reactive capability above the statutory requirement.
- The sensitivity of Transmission constraints to the reactive injection and absorption services provided at each DER site, which in turn is a function of the position of the DERs on the network relative to that constraint

Based on the assumption that existing DER connected at 11kV and above can be connected under the ANM system and provide 100 MVAr of reactive compensation, and that all new DER (with volumes shown in Figure A10.1) are connected under the ANM scheme. In order to be conservative, it was assumed that each DER only provides the statutory minimum capability (0.95 lead/lag power factor), and that no other technologies such as batteries are brought under the scheme.

Having carried out initial network analysis that suggests the sensitivity, on average, of the Transmission network constraints to existing DERs ranges from 40% to 83%. For the purpose of this CBA we have assumed a general sensitivity of 67% on the understanding that the TDI project will encourage new DER connections in areas where they are more technically capable of delivering the services. Note that this assumes that tap controls are not installed at all primary substations and GSPs; doing so is expected to increase this sensitivity, but comes at a cost.

The methods that have been considered in the Cost Benefit Analysis are:

1. Today's model – (known as Business as Usual Approach)
2. Method 1 - Dynamic Voltage control from Distributed Energy Resources with reactive compensation in transmission system only
3. Method 2 - Dynamic Voltage control from Distributed Energy Resources with reactive compensation in transmission and distribution system

By applying the same logic for estimating shunt, SVC and STATCOM requirements as was used under the today's model scenario, but accounting for the offsetting effect of the DER services, the Transmission capex spend profile is reduced as shown in Figure A10.3. The dynamic voltage control (DVC) service provided by DER is comparable to the service provided by STATCOM units and therefore it is assumed that under the TDI 2.0 scenarios further STATCOM unit installation is not required. Furthermore, the capex expenditure on shunt reactors and SVCs is lower due to the increased MW transmission capacity provided by newly connecting DERs. Figure A10.3 therefore shows that the expected capex on FACTS units is significantly reduced under the TDI 2.0 scenarios.

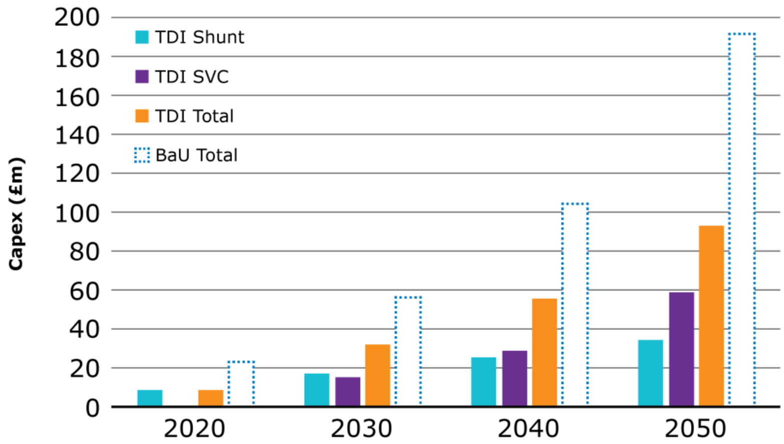


Figure A10.3 Capex profile under TDI scenarios

The TDI 2.0 scenario involves the use of DER reactive and active power services, which will involve NGET incurring operational costs that were not present in the BaU scenario. It was assumed that reactive services are procured at a fee consistent with the Obligatory Reactive Power service (£3/MVArh), and that active power reduction reflects the opportunity cost of curtailed DER (on average £100/MWh reflecting wholesale price and renewable subsidy).

In the calculation of the TDI 2.0 operating costs, a conservative assumption was made that in order for the DER units to provide the DVC service (at a power factor of 0.95 lead/lag) active power output has to be curtailed by 5%. In practice this may be true for some existing DERs such as solar PV, which under their connection agreement must operate at unity power factor, which do not have the capability of supplying reactive power services at full rated active power output. But it is expected that DERs connecting post trial commencement will be required to operate between a power factor of 0.95 lead/lag at full rated active power output. It may be required to financially incentivise the connection of DERs in order to provide the financial certainty around the added cost of this technical capability. The scale of this financial incentive will be discovered during the project trials which will reveal whether this cost is lower than the cost of curtailing DER active output. If it is this could represent a further significant benefit of the TDI 2.0 scenario.

The Cost-Benefit Analysis performed for this project is based on the Spackman approach [1] which clearly presents the financial benefits of each of the methods being trailed in the project at four time points (2020, 2030, 2040 and 2050) on a cumulative basis. After combining the capex and opex for all scenarios, Figure A10.4 shows that the TDI 2.0

scenarios have a clear net benefit over the BaU scenario with Method 1 and Method 2 culminating in net benefits of £25.7m and £29.0m respectively by 2050.

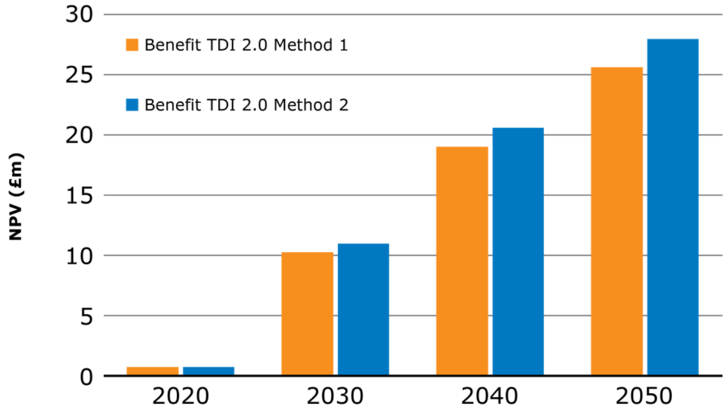


Figure A10.4 Benefit of TDI scenarios compared to BaU Scenario

Table 1 displays the breakeven analysis of the project which presents the number of years when the NIC project cost (£9.5m) can be recovered from the added benefit under the TDI 2.0 scenarios. It shows that Method 2 recovers the project cost at a faster rate with the net benefit surpassing project costs by 2030 compared to Method 1 in 2032.

Method	Breakeven Year	NPV of Benefit (£m)	Number of Years (Excluding Initial Years)
Method 1	2030	9.5	10
Method 2	2030	9.5	10

Table 1 Breakdown Analysis

The breakeven number of years is calculated as minimum number of years for which NPV of TDI 2.0 net benefit will be equal to or greater than the NIC funding.

A10.6 Benefits of Storage and DSR

In this CBA, the conservative assumption that only DER participates in the provision of services was made. In reality, both battery storage and demand side response (DSR) could play important roles in the management of transmission network constraints. In particular, these resources create competition for active power curtailment services which NGET looks to procure to manage thermal and voltage constraints. Currently in the South-East NGET is curtailing interconnector flows which has an average cost of 90% of the wholesale electricity price. In the BaU case, the expected opex on interconnector curtailment rises from £0.26m to £0.53m a year by 2026. Storage and DSR can potentially offer curtailment and demand turn-up services at a more competitive price, thereby resulting in opex savings in the TDI scenarios.

A10.7 Non-financial benefits

Because of the way in which the TDI 2.0 scenario was defined, there was no difference in the level of DER deployed, so there would have been no substantial carbon impact. However, in reality we know that the connection of DER is currently being held up because of the transmission constraints. It is reasonable to expect even if efforts were made on the transmission network to alleviate these constraints, delays and barriers to future DER connection would be expected.

If no DER were allowed to connect, if this would have been renewable generation, and if there were no compensatory investment elsewhere on the network, the use of TDI 2.0 to alleviate this bottleneck would result in significant carbon reductions, as shown in Figure A10.5.

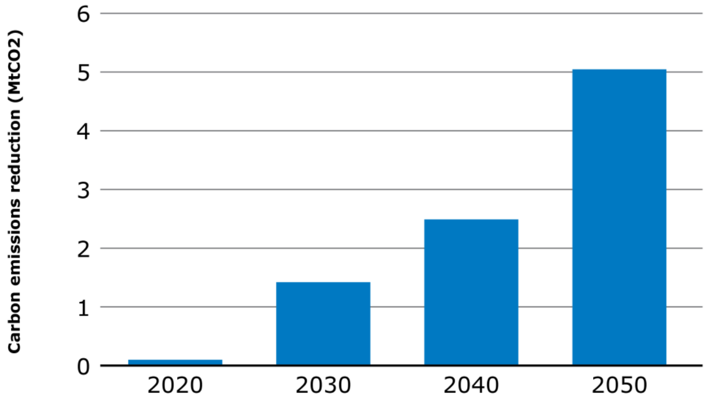


Figure A10.5 Carbon reduction associated with projected DER deployment vs average grid carbon intensity

At a rate of 23.38 £/tonne, this would have a value to society of £57.7m in 2050. However, this should not be seen as being in addition to the financial benefit already estimated above, since this is based on a different set of assumptions.

Furthermore, Figure 10.5 should be seen very much as an upper limit for a number of reasons:

- A DER developer unable to connect to this part of the network may opt for a different project elsewhere on the network, which may not otherwise have gone ahead
- Even if this were not the case, the Levy Control Framework constrains the level of subsidy available, meaning that if one renewable DER project does not proceed there is more money available for future projects

For these reasons, focusing should be on the main financial benefit already expressed above. But it is nonetheless true that there is likely to be a reduction in carbon emissions associated with this project, and at the very least a reduction in the cost associated with achieving the desired carbon reduction.

A10.8 References:

[1] Discounting for CBAs involving private investment, but public benefit, 25 July 2012, published by the Joint Regulators Group (JRG)

ofgem

RIIO NIC NETWORK INNOVATION COMPETITION

Appendix 11 Letters of Support

Imperial College London

Department of Electrical and Electronic Engineering
Imperial College London

Room 1101
South Kensington campus
London SW7 2AZ, UK
Tel: +44 (0)20 7594 6169 Fax: +44 (0)20 7594 6282
g.strbac@imperial.ac.uk
www.imperial.ac.uk/controlandpower

Prof Goran Strbac
Professor of Energy Systems

Network Innovation Competition proposal:
Transmission Distribution Interface (TDI) 2.0

Biljana Stojkovska *National Grid*
Sotiris Georgiopoulos *UK Power Networks*

24 July 2016

Dear Biljana and Sotiris,

Transmission Distribution Interface 2.0

Given the changes in generation mix across the country, increase in the interconnectors with EU combined with deployment of local PV generation and offshore wind, the transmission network in South East of England is facing challenges of unprecedented proportions. In the event of an outage of the 400kV circuits in the south-coast line between Kemsley and Lovedean, and depending on the exact export/import condition on the interconnectors, the power transfer could be very high leading to severe thermal and voltage problems. Similar problems are occurring in case when high interconnection imports coincide with low demand and high PV outputs in London region, which also makes the management of voltage stability increasingly more difficult.

If the traditional passive operation and design paradigm is maintained, substantial electricity infrastructure reinforcements will be required leading to high investment and low utilisation of transmission and distribution network capacity.

This highlights the significant opportunity and the need for closer interaction between NGET and UKPN, which will be trailed for the first time within TDI 2.0 project, given that various distributed energy resources in the South East area could support management of thermal and voltage driven transmission network constraints. In this project UKPN will dynamically manage the synergies and conflicts between distribution and transmission network objectives when allocating DSR flexibility. In this context, UKPN will provide secure access of distributed energy resources to NGET, which will be the key for cost effective and secure management of thermal and voltage driven transmission network constraints in the area. This will also meet the increasing appetite from owners and operators of distributed energy resources to provide network services and demonstrate the ability of smart grid solutions to substitute for conventional network reinforcements. In this context, Imperial team has supported the development of the business case for TDI 2.0.

Imperial College of Science, Technology and Medicine

However, this transition in system control paradigm will involve a significant increase in complexity of the system real time management and operation, as well as market arrangements, which will be fully explored within TDI 2.0. This project will demonstrate the opportunities and challenges of the new control architecture as full integration of DER within UKPN areas could enhance the utilisation of transmission network capacity and transform the operation of South East network, which will be critical for rolling out the TDI 2.0 concepts that would support optimal development of the future GB system as well as support cost effective transition to a smarter and lower carbon energy system.

In this context Imperial College proposed several tasks to be carried out within the TDI 2.0 project, focusing on quantifying the security, economic and carbon performance of the proposed development of Transmission-Distribution control interface, including:

- *Validation of the Virtual Power Plant control platform through computer simulation*
  Based on conducted trials, comprehensive analysis will be carried out to validate both preventive and corrective control actions derived by the proposed software platforms for integration of UKPN and NGET systems.
- *Quantifying the value of VAr services provided by distributed energy resources*
  This task would involve application of novel modelling based on advanced Sensitivity Analysis based Security Constrained Optimal Power Flow develop by Imperia team, to select optimal portfolio of VAr support contracts offered by distributed energy resources to maintain system security across a number of loading conditions while taking into account location and credible contingences.
- *Risk profile of the application of TDI solutions for control of transmission network*
  As it is critical to fully understand the risks associated with the smart grid paradigm, this task will quantify of the risk profile associated with the application of proposed control strategies based on distributed energy resources to manage transmission network constraints.
- *Option value of DER contracts in South East network*
  This will involve application of stochastic and least-worst regret decision analysis designed to identify a robust portfolio of contracts for distributed energy resources to deal with uncertainty in timing, amount and location of future generation, demand and interconnection deployment.
- *Benefits of rolling out TDI 2.0 paradigm to other areas of the GB system*
  This work will involve evaluation of the benefits of rolling out the concept of Transmission-Distribution Interface developed for the South East network to other parts of the GB system, under different future development scenarios.

Yours sincerely

Goran Strbac

Prof Goran Strbac

Imperial College of Science, Technology and Medicine

origamienergy

Dr. Biljana Stojkovska
Innovation NIC Project Manager
Electricity Network Capability, System Operator
National Grid House, Warwick Technology Park,
Gallows Hill, Warwick, CV34 6DA

1st August 2016

Transmission Distribution Interface 2.0 project

Dear Biljana,

We are pleased to offer this letter of support for your proposed project to identify the means by which distributed energy resources can be shared efficiently and effectively between TSO and DSOs.

Coordination across national and local requirements is central to Origami's vision of how flexible assets can enable a cheaper, greener and more reliable electricity system. We have developed our own technology platform to support this vision and consider in real time the most valuable way to deploy the flexibility of a diverse portfolio of assets across multiple services and price signals.

We are interested in supporting the project on several fronts; including asset recruitment, technology provision and thought leadership on commercial arrangements. There are clearly critical links between these workstreams and it will be vital to keep them closely aligned. We believe it would be beneficial to have partners involved in multiple workstreams where possible. In addition, we are willing to contribute towards the project in terms of provision of resource and equipment, ensuring good value for Distribution and Transmission customers.

Potential asset partners that we have engaged, including operators of renewable generation, have indicated interest in participating in the project, and in similar opportunities outside of the South East of England. They are understandably keen to understand any impact on their asset's core operations and to help shape commercial arrangements, particularly pricing and commitment levels, to reflect this.

We believe that systematic sharing of assets between National Grid and DNOs is necessary to underpin more efficient use of flexibility in the future. However, there are other system actors that will compete for control of these same assets, in particular energy suppliers. Additionally, it seems certain that market arrangements will continue to evolve during the life of the project. The project will need to consider how it can demonstrate the core principle of TSO/DSO cooperation while working with other systems that emerge in the future.

We are grateful to have had the opportunity to discuss your proposal and, if selected, look forward to working together to shape the detail over the next few months.

Amanda King

Amanda King
Chief Financial Officer, Origami Energy

Origami Energy Limited. Registered Address: Ashcombe Court, Woolsack Way, Godalming, GU7 1LQ, UK.
Registered in England. Company Number 8619644. VAT Number 169210217

limejump

Limejump Limited
Elizabeth House
39 York Road
SE1 7NQ
Tel: 02083966834
21st July 2016
Email: info@limejump.com

Dear Sir/Madam,

Limejump is interested in participating in project TDI 2.0, as led by National Grid. If the project bid is successful, we would look to deliver reactive power services.

Erik Nygard

Yours sincerely,

Erik Nygard

Chief Executive Officer

Lightsource

Chris Buckland
Technical Director
Lightsource Renewable Energy Holdings Ltd
33 Holborn
London EC1N 2HU

Dr. Biljana Stojkovska PhD CEng MIET
Innovation NIC Project Manager
Electricity Network Capability, System Operator
National Grid House, Warwick Technology Park,
Gallows Hill,
Warwick, CV34 6DA

21 July 2016

Subject: Letter of support and interest to participate in National Grid Electricity NIC year four screening submission for Transmission & Distribution Interface 2.0 (TDI 2.0) Publication date 21st April 2016

To whom it may concern,

Lightsource Renewable Energy Holdings Ltd has held preliminary discussions with National Grid with regard to the development and trialling of grid support services derived from large-scale solar PV in the form of the provision of reactive power on demand.

Whereas Lightsource manages in excess of 1 GW of UK solar generation assets, these are currently engineered to export electrical energy. Modifications of the installed technology would enable the provision of additional grid services such as reactive power both during the day and at night.

In the event that the above referenced National Grid program proceeds, Lightsource would be keen to participate as a partner with National Grid in developing and trialling the necessary technology required to extend the capability of our existing generation assets. We confirm that equipment suppliers, engineering specialist and additional personnel resources would be made available to support the program throughout the project lifecycle.

With best regards,

C Buckland

Lightsource Renewable Energy Holdings

ARENKO CLEANTECH LIMITED

Arenko Cleantech Limited
5 Lambton Place
Notting Hill
London
W11 2SH
4 August 2016

Dear Mr Do,

Re: TDI 2.0 Network Innovation Competition

It was a pleasure to speak with you and the Smart Grid Development team at UKPN where we discussed recent activities on grid-connected energy storage systems and how we may work together in the future. We are currently looking at constructing several grid level energy storage systems (up to 50MVA) across the UK and we believe the work outlined in your project will be valuable to the efficient utilisation of energy storage systems in future.

Your proposed project into alternative solutions to grid constraints, in particular reactive power and voltage control, are of interest to us as an energy storage service provider. A better of understanding of the issues and needs of the local network will allow us to more accurately specify systems to ensure that any envisaged charge/discharge models are economically viable. This, in turn, will allow us to more effectively and economically provide multiple services to the grid.

To support your work, should your application be successful, we would be willing to work with UKPN and NGET to locate one of our future projects in the proposed area, and to work with you to develop replicable service models. In addition, we would be happy to commit ourselves to becoming members a project steering committee and attending 2 meetings per year.

This work is timely and of great importance to the energy storage community and the UK as a whole, and therefore we are happy to be involved in supporting the project.

Good luck with your application.

Best regards,

Andy

Andy Hadland
Chief Development Officer
Arenko Cleantech Limited

Flexitricity

29th July 2016

Exchange Tower
19 Canning Street
Edinburgh EH3 8EG

t: 0131 221 8100
f: 0131 629 9375
w: www.flexitricity.com

Dear Dr Stojkovska

Thank you for introducing me to your TDI 2.0 project. I can confirm that this project is of considerable interest to Flexitricity, and we would be very keen to be involved in it as it goes forward.

Flexitricity pioneered open-market demand response in the GB electricity system. We were the first to launch, the first to being 24-hour operations, the largest contributor of demand response to the Low Carbon Networks Fund, and the initiators of what is now the Demand Turn-Up service for wind and solar balancing.

I see TDI 2.0 as the next step for demand response. It is a technically challenging one. Up to now, active customers and small generator owners have concentrated on real power, leaving the more technical matters such as voltage management and reactive power to the network operators. It has long been clear that customers can have a role here, but the split between transmission and distribution has up to now made this impossible to develop. However, the consortium you have assembled directly addresses this barrier.

One particularly attractive feature of your proposal is that your chosen zone for the project is one where our customers have a considerable asset base. While customer recruitment is often the toughest part of demand response, we have seldom been able to start a project from such a good foundation.

I look forward to working with you as the project develops.

Yours sincerely

Alastair Martin

Dr Alastair Martin
Director

REGISTERED OFFICE:
Exchange Tower, 19 Canning Street, Edinburgh EH3 8EG

Registered in Scotland No 263298

SP ENERGY NETWORKS

Biljana Stojkovska
Innovation NIC Project Manager
Electricity Network Capability, System Operator
National Grid House,
Warwick Technology Park,
Gallows Hill,
Warwick, CV34 6DA

27 July 2016

Ref: TDI 2.0 NIC Project

Dear Biljana,

This letter is in support of the TDI 2.0 project, to be submitted to OFGEM within the Network Innovation Competition framework.

The project focusses on a trial area that is at the limit of capacity for importing and exporting power from the rest of the transmission system. It aims to demonstrate that there are untapped resources on the distribution network that can be reliably tapped in real time.

These are also issues that we face within our distribution and transmission licence areas, and we believe that improved management of distributed energy resources on the distribution network forms part of the solution. We therefore believe that TDI 2.0 has the potential to deliver valuable learning to SP Energy Networks and other licensees.

TDI 2.0 is complementary to our own INSPIRE project proposal which aims to demonstrate a new way for DNOs to manage their network information, which will help to facilitate techniques such as those developed under TDI 2.0.

We look forward to sharing learning from TDI 2.0 and we will participate in the stakeholder consultation and knowledge dissemination events.

Yours Faithfully,

Watson Peat
Lead Engineer, Future Networks

Ochil House, 10 Technology Avenue, Hamilton International Technology Park, Blantyre G72 0HT
Telephone 0141 614 0008
www.spenergynetworks.com

Printed on 100% recycled paper

Foresight group

The Shard
32 London Bridge Street
London SE1 9SG

t: +44 (0)20 3667 8100
e: info@foresightgroup.eu
w: www.foresightgroup.eu

National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

27 July 2016

Transmission and Distribution Interface 2.0 (the "Project")

Dear Sirs

We are aware that UK Power Networks and National Grid are preparing a proposal for a Network Innovation Competition funded project for submission to Ofgem.

We understand that this is an investigation project and that UK Power Networks and National Grid are seeking parties with the capability of providing reactive power services in conjunction with active power services. Foresight Group has expressed interest in the Project, subject to its approval, all necessary due diligence and Foresight Group Investment Committee approval.

Yours faithfully

Daniel Wells, Director
Foresight Group LLP

Foresight Group LLP No. OC300878 (registered in England and Wales) is authorised and regulated by the Financial Conduct Authority. VAT Reg No. GB 172 2417 27

Imperial College London

Department of Electrical and Electronic Engineering
Imperial College London

Room 1104
South Kensington campus
London SW7 2AZ, UK
Tel: +44 (0)20 7594 6172 Fax: +44 (0)20 7594 6282

b.pal@imperial.ac.uk
www.ee.imperial.ac.uk/CAP

Bikash Pal PhD, FIEEE
Professor of Power Systems
Editor-in-Chief, IEEE Trans on Sustainable Energy

29 July 2016
Sam Do
Smart Grid Development
UK Power Networks
Newington House, 237 Southwark Bridge Road, London SE1

Sub: Expression of interest for participation in NIC proposal: **Transmission Distribution Interface (TDI) 2.0**

Ref: **Active Control and Optimization through DER for Resolving Network Constraints**
Dear Sam
Many thanks for bringing this possible NIC proposal into my attention. Looking at the overview of the proposal, it is very clear that control and estimation for network operation optimization is going to be very essential part of this activity.
We are all aware that South East part of electricity network in the UK has been suffering from operational constraints acting as significant barriers for the available DER to make technically beneficial impact on the network operation. Faster and scalable state estimation tool which are not yet deployed in DNO control centre will be very much required to drive various voltage control mechanism for control of system voltage in co-ordination with automated feeder reconfiguration to alleviate those constraints. This in turn removes the barrier in accommodating more output from DERs into the network. The network voltage violation can be addressed by coordinated Volt-VAr Control (VVC) while the line overloads can be controlled by Optimal Feeder Reconfiguration (OFR). In the present practice of operating the distribution network these tasks are performed without coordination, providing less effective network condition to accommodate DERs. I will be very pleased to be part of developing a robust state estimation algorithm that handles the combined problem of coordinated VVC and OFR in the UKPN network with DER that will be allowed to make maximum technical benefit in network operation. In the past we have developed some technical tool for state estimation in the network and voltage control with strong support from UKPN and it is an ideal opportunity to take them higher TRL level through this activity. I am interested to address the convergence, scalability and robustness aspect of the functional computation for network control addressing the scalability.
I am sure this National Grid and UK Power Networks jointly led programme will propose to address a broad sets of technical challenges at the transmission and distribution interface. While very unhesitatingly I support this programme, as an academic partner, my activity in this programme will be focused on the development and deployment of the control and computation tools for alleviating network congestion. My participation will also be contingent upon receiving active support and financial resources from UKPN.

Please let me know, if you need anything further.
Sincerely yours

Imperial College of Science, Technology and Medicine

MANCHESTER 1824
The University of Manchester

Prof V Terzija
School of Electrical and Electronic Engineering
The University of Manchester
Po Box 88
Sackville Street
Manchester
M13 9PL

+44(0)161 306 4695
www.manchester.ac.uk

National Grid
EUR ING Dr. Biljana Stojkovska PhD CEng MIET
Innovation NIC Project Manager
Electricity Network Capability, System Operator
National Grid House, Warwick Technology Park,
Gallows Hill, Warwick, CV34 6DA
T: +44 (0)1926 654696
M: +44 (0)7826 944782
e-mail:biljana.stojkovska@nationalgrid.com

21 July 2016

Dear Ms Stojkovska,

Subject: Letter of Support for NG and UKPN NIC Bid TDI 2.0

As a Chair Professor of The University of Manchester and participant in several NIC projects (VISOR, EFCC and FITNESS), as well as the academic principal investigator of Horizon2020 MIGRATE EC funded project which is strongly linked to challenges described in the TDI 2.0 project scope, I am delighted to provide my strong support to National Grid and UK Power Networks in their attempt to get project approved from Ofgem.

The University of Manchester has leading internationally recognized researchers in the area of power system monitoring and control, as well as world-class hardware in the loop laboratory facilities and would be willing to assist National Grid and UK Power Networks in this project.

I am particularly supportive of the proposed TDI 2.0 project objectives because:

- This project has massive value for future optimal operation of the GB power system, in particular the South-East GB grid.
- The lessons learned in this project will be used in other parts of the grid.
- The project has both significant value, from the perspective of reducing the costs and opening the opportunities for more effective utilization of the existing assets, but also inspiring novel applications.
- The project is addressing issues which are relevant not only for the GB grid, but also for other utilities worldwide.

In conclusion, I strongly support National Grid and UK Power Networks in their ambition to demonstrate such an exciting and important solution which will definitely contribute to the quality of power supply in the UK.

Yours sincerely

Prof Vladimir Terzija

Prof V Terzija
EEPS
School of Electrical and Electronic Engineering
0161 306 4695
0161 306 4820

Appendix 12 Glossary

ANM	Active Network Management
AVC	Automatic Voltage Control
BSUoS	Balancing Services Use of System Charges
CBA	Cost Benefit Analysis
DBEIS	Department of Business Energy and Industrial Strategy
DER	Distributed Energy Resources
DG	Distributed Generation
DVC	Dynamic Voltage Control
E	Effective
EE	Extremely Effective
ENA	Energy Networks Association
FDG	Flexible Distributed Generation
GSP	Grid Supply Point
GSoP	Guaranteed Standards of Performance
ICCP	Inter-control Centre Communication Protocol
ICT	Information and Communication Technologies
IRR	Internal Rate of Return
ISP	Initial Screening Process
KASM	Kent Active System Management
LCNF	Low Carbon Networks Fund
LIFO	Last In – First Out
NE	Not Effective
NGET	National Grid Electricity Transmission
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
ORPS	Obligatory Reactive Power Service
PDA	Project Design Authority
PMO	Project Management Office
RFI	Request for Interest
RFP	Request for Proposal
SE	Somewhat Effective
SF	Sensitivity Factor
SO	System Operator
SRMC	Short Run Marginal Costs
Shunt Reactor	A shunt reactor is an absorber of reactive power
SVC	Static VAR compensator
STATCOM	A STATCOM is a voltage source converter (VSC)-based device, with the voltage source behind a reactor.
TNUoS	Transmission Network Use of System Charges
UKPN	UK Power Networks
VE	Very Effective
WPD	Western Power Distribution