Operational DER Visibility and Monitoring

Open Networks

Cost Benefit Analysis | February 2022

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1. Glossary

Acronym	Description
API	Application Programming interface – web based data transfer.
A/D	Analogue to Digital converter
APRS	Automatic Power Restoration system
CBA	Cost Benefit Analysis
CT/VT	Current Transformer/Voltage Transformer
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
ECR	Embedded Capacity Register
EMS	Energy management System
ICCP	Inter Control Center Communication Protocol
IED	Intelligent Electronic Device
LFDD	Low Frequency Demand Disconnection
POC	Point of Connection
VOLL	Value of Lost Load

2. Executive Summary

On Friday 9th August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply. During this event, a large number of Distributed generators (DGs) [1]tripped or de-loaded, which contributed to a large instantaneous frequency deviation and therefore the low frequency demand disconnection (LFDD) protection scheme triggered to protect the system and restore system frequency to within the appropriate standards.

Having carried out analysis on the level of operational visibility Distribution Network Operators (DNOs) have over generation sites, it has been identified that there is a considerable gap in monitoring. The key findings have been:

- DNOs lack visibility of around 20% of the total export generation capacity, corresponding to 7.4 GW out of the 35.8 GW of generation capacity connected on DNOs network across GB.
- Most of the invisible generation capacity is connected to the HV network: out of the 7.4 GW of un-monitored capacity, 1.5 GW are connected to the EHV network and 5.9 GW on the HV network.
- The total 7.4 GW on unmonitored capacity is mostly made up of generators in the 1-10MW capacity bracket making up 5.9 GW of capacity, and corresponding to the 79% of the total. The remaining unmonitored capacity is composed as follows: 3% in the 0-200kW capacity bracket, 4% in the 200-500kW capacity bracket, 5% in the 500-1MW capacity bracket, and 9% of sites with capacity above 10MW.

This poses a challenge in managing the network both for DNOs and ESO. DNOs are currently blind over the majority of HV connected generators, which affects automation programmes and lead to take conservative assumptions running the network. Lack of visibility also poses considerable operability challenges to the ESO including in abnormal network events, such as low frequency disconnections.

Given these challenges, Ofgem has directed to the Energy Networks Association (ENA) Open Networks Programme (ONP) to work with network companies and relevant stakeholders to quantify the investment that would be required for monitoring as well as the potential value that DNOs and ESO will have from the enhanced visibility, which is what this document intends to advise on.

It has been identified that the total capital expenditure to retrofit the entirety of the DG sites which are currently not monitored, varies from £70M to £132M. If the DG capacity threshold to retrofit is increased to 1MW, the capital expenditure varies from £25M to £42M.

The combined DNOs and ESO benefits unlocked by the enhanced DG visibility, which are ultimately reflected into customers benefits, have been quantified to be in the range between £3 -27M/ year. In addition, there may be additional benefits that are more challenging to quantify at this time, for example impacts on future ESO/DSO requirements such as operational co-ordination.

Cost Benefit Analysis results showed that the benefits from the additional DG visibility with capacity below 1MW, which accounts for a total 0.66 GW of capacity, are not considerable compared to the benefits that would be unlocked from the visibility of DG with capacity 1MW and above, which accounts for total 6.6GW. This assessment may change in the future with further maturing of flexibility markets and DSO.

3. Background

3.1. Ofgem's Call for Evidence on DG Visibility

On Friday 9th August 2019, a power outage caused interruptions to over 1 million consumers' electricity supply. During this event, a large amount of DG tripped or de-loaded resulting in demand disconnection being triggered in order to protect the system and bring system frequency back under control.

Following this event, Ofgem opened an investigation into the power outage which resulted in nine specific and measurable actions. Action eight highlighted the need for Ofgem to investigate and consider options to improve real time visibility of DG to DNOs and the ESO[2].

In August 2020, Ofgem published a call for evidence on DG visibility, highlighting the shortfall in the collection and recording of real-time data associated with distributed generation, clearly signalling their intention to establish a policy on DER monitoring requirements.

The industry responses received to the call for evidence agreed that there are significant shortfalls in DG visibility. However, Ofgem noted a lack of articulated set of use cases for DG data visibility, and agreed that further industry analysis was required to inform policy decisions.

3.2. WS1B P6 Work delivered in 2021

Ofgem has then directed the Energy Networks Association (ENA) Open Networks Programme (ONP) to work with network companies and relevant stakeholders to provide a clearer articulation on exactly how enhanced DG visibility would contribute to assisting the ESO and DNOs at present and in the future; what data measurements enhanced visibility of DG should include; the costs and benefits of enabling such visibility; and how governance changes should be implemented. The requirement from WS1B P6 2021 were:

1) Definition of use case variables/DER data points (Deliverable A)
2) Agreement on use cases and volumes (Deliverable B)
3) Development of functional specifications (Deliverable C)
4) Undertake Cost benefit analyses against the articulated use case (Deliverable D)

A summary of the key activities and outcome of the work delivered by the product team in 2021 [3] is summarized below.

3.2.1. Use cases identification

The first step was the identification of current and future use cases that could benefit from an enhanced DER visibility and monitoring, both at transmission and at distribution level. The use cases, summarized in Table 1, capture all prospective DER-DNO/ESO interactions (service or activity) that will make use of data applicable to the DER Point of Connection (POC) data.

Table 1: Identified DER visibility Use Cases

Use Cases Definition		
Category		**Use Case**
DER providing service to DNO only	1	Flexible Connections dispatch (ANM)
	2	Flexibility Service dispatch
DER providing service to ESO only	3	Ancillary and Balancing services
	4	System Restoration (Black Start)
	5	Capacity Mechanism Planning

[2] . https://www.ofgem.gov.uk/publications-and-updates/investigation-9-august-2019-power-outage

[3] on21-ws1b-p6-operational-der-visibility-and-monitoring-requirements-(13-dec-2021).pdf (energynetworks.org)

DER providing services to a DNO and ESO	6	Whole system coordination (resolving conflicts of services)
All DER – Improvement of existing processes	7	Improved System Resilience
	8	Improved real-time Network Operation
	9	Improved Outage Planning (DNO)/ Network Access Planning (ESO) processes
	10	Improved Network Planning (DNO)/ Long-term network development (ESO) processes
	11	Improved Demand forecasting processes
	12	Real-time DSO Data transparency
	13	DER compliance with relevant standards
Market Facilitation (Non-DSO services)	14	Facilitation of new Markets (e.g. peer-to-peer)

3.2.2. Volume and impact of use cases

Use cases have then been quantified in terms of volume of real-world instances and impact that each of them have.

- **Volume**: frequency of occurrence of the use case and as an extension, how often does the use case makes use of the operational DER data.
- **Impact** that low DER data accuracy/resolution or complete lack of DER visibility can have on the category below
  - Network Risk: risk of overloading or damaging physical network assets/safety of personnel;
  - Commercial: risk of lost revenues/ losses from the market participants;
  - Stability GB system – risk of partial shutdown/blackout of the GB system.

Outcome of the assessment is available in Section 5 of the WS1B P6 2021 report.

3.2.3. Data points identification and Use Case Mapping

A comprehensive set of DER data points that may be required and/or be beneficial for the identified use cases, have then been identified and are summarized below:

- **Operational metering data**, including Amps, Volts, Watts and VARs plus breaker data.
- **Other raw PoC real-time data**: power factor of operation, frequency, power quality monitoring, protection operation, read back signals and mode of operation (PV/PQ).
- **Weather data:** wind speed, temperature information at the PoC.
- **Forecast Data**: Forecasted DER output either declared forward-looking availability from the DER or generated by forecasting system based on e.g. weather data.
- **Availability Data**: data on DER availability, including real time availability (DER in service/out of service) and capacity in service, as well as forward looking DER availability due to planned outages.
- **Market Data**: DER data detailing service DER has been contracted for, volume requirement, service window, and delivery season etc.
- **Processed data:** DER data that requires processing/analytical steps including load factor, power available, state of energy.
- **Static Data: offline DER data including capacity, PQ envelope, protection settings, maximum ramp rates etc.**

For each of the use cases, the identified data points have been categorized as “Essential” (E), “Desirable” (D) or “Not required” (N) data points.

Full data points list and mapping is available in Section 6 and 7 of the WS1B P6 2021 report.

3.2.4. Functional specification (deliverable C)

The ask for the next activity was to define the metring functional specifications for the identified data points based on the use case DER participate into. To carry out this piece of work the data in scope have been restricted to Operational Metering data.

OPERATIONAL METERING FUNCTIONAL SPECIFICATIONS GENERATION SITES NOT MONITORED

The approach we took for defining functional specifications is a benchmark exercise on the highest spec monitoring equipment that DNOs would install for new connections at different voltage levels, based on which we have derived the baseline functional specification, including measurement accuracy and resolution of data capture requirements.

We took this approach rather than a use case specific specification as DNOs would retrofit an 'invisible' site by installing the highest specs monitoring equipment that would be installed for a new connection regardless of the use case DER are participating to.

A) Measurement accuracy

We identified sources of inaccuracy in the metering equipment and quantified the accuracy of each of the components which was then used to determine the baseline specification that new sites would meet. Sources of inaccuracy that measurement are subject to are summarized below:

CT/VT

- Accuracy in the CT/VT (CT/VT class)
- Metering vs protection CT. Generally, SCADA applications use Protection class CT for EHV 132 kV and 33kV and Metering class CTs for HV RMU connection. Protection CT are very accurate at fault current which is the current range at which protection operates and less accurate at nominal current compared to metering CT.

IED (intelligent electronic device)

- The type of IED (whether is a protection relay or measurmeent relay i.e. transducers and PQM),
- Resolution of the Analogue to digital (A/D) converter
- Measurement range of the IED
- Accuracy of the IED

A benchmark exercise across DNOs showed that the accuracy of Amps, Volts, Watt and VARs measurement is above 95%. Detailed table is available in Section 8 of the WS1B P6 2021 report. [4]

B) Resolution of data capture

Resolution of data capture influences the frequency a new measurement is made available and exposed to the various systems making use of the data (ADMS, DERMS, IEMS etc). It does not capture the latency involved in transmitting the data.

Resolution of data capture is primarily influenced by the dead-banding configuration in the RTU: DNO would usually set a dead-band around the measurement change seen from the RTU, such that if the measurement change is below a certain percentage, the RTU would not poll the measurement. The dead-banding around the measurement change has been introduced avoid saturation of DNO's communication network for a minimum measurement change and it is set by each DNO based their individual communication infrastructure.

[4] on21-ws1b-p6-operational-der-visibility-and-monitoring-requirements-(13-dec-2021).pdf (energynetworks.org)

Benchmark exercise across DNO showed that measurement would be polled for a measurement change of at least 1% of the nominal value (e.g. if nominal range 1000 Amps there would be a 10 amps dead-band, which for a 33kV site corresponds to 0.57 MW)

OPERATIONAL METERING FUNCTIONAL SPECIFICATIONS FOR FULLY MONITORED SITES

DG sites where DNOs already have complete operational metering visibility (Amps, Volts, Watt, VARs), may have low measurement accuracy and infrequent resolution of data capture, not meeting the baseline functional specifications defined above. This may be the case for legacy generators commissioned long ago, equipped with monitoring devices using lower class CT/VT instrumentation, and lower analogue to digital bids conversion, resulting in lower overall accuracy. The product team has not investigated the accuracy of legacy generators connected to the network.

4. Objective and approach

4.1. Scope and Objective

The final ask for WS1B P6 2021 deliverable was to derive a cost-benefit analysis (CBA) framework for DER/DG visibility and monitoring against the use cases previously defined. In particular the ask was to:

- Quantify the investment that would be required for monitoring, collecting, storing and disseminating real time operational data associated with DG POC
- Assess if the cost varies based on the size of visible DG
- Quantify the value that additional data points will provide to improving the planning, security and real time operation of the GB transmission and distribution systems
- Quantify the value will the above characteristics provide to improving DSO function delivery including network management, flexibility procurement, and service conflict avoidance by the DNOs or other stakeholders

The outcome of product 6 CBA deliverable, will provide inputs to inform the development of the policy on DER monitoring requirements including to the proposed grid code modification GC0139: 5 'Enhanced Planning-Data Exchange to Facilitate Whole System Planning', which seeks to increase the scope and detail of planning-data exchange between DNOs and the ESO to help facilitate the transition to a smart, flexible energy system.

4.2. Approach and Methodology

This section summarizes the approach we took to produce the final CBA results.

GAP Analysis

We first carried out a Gap -Analysis to assess the level of visibility that DNOs currently have over generation sites, specifically looking at operational metering (P,Q, V, I and breaker status). The output was the number of sites and capacity on which DNOs have full metering (P, Q, V, I, CB status), partial metering (e.g. only Amps) and no metering (DNO equipment), for each voltage level.

CAPEX and OPEX Cost

We then looked at the cost (Capital and Operational) of retrospectively fitting monitoring equipment on sites which DNOs don't have any visibility or only have partial visibility (e.g. only Amps) over.

The cost of retrofitting sites to get real time monitoring varies considerably based on the equipment already installed on site. These include variances in the availability of metering unit, of the transducer, on the type of RTU installed, on the age/state of the switchgear, on the voltage level of the connection and on the comms availability.

It would require a site-by-site investigation to come up with precise retrofit cost for each site, which is both resource and time intensive. As a reasonable approximation, the approach we have taken is to create retrofit cost scenarios for each voltage level, which takes into account all likely scenarios that DNOs would come across to retrofit DG sites and associated cost of retrofitting in each scenario.

Beside the DG retrofit cost we have assessed the other cost DNOs would incur to get the additional data points form the DER POC to the DNO Distribution management system (DMS), including cost for additional data storage as well as the yearly operational expenditure driven by the additional sites on SCADA.

USE CASE BENEFITS

We then looked at the benefits that ESO, DNO and customers will have from the enhanced DG visibility, specifically looking at the use cases previously identified: improving the planning, security and real time operation of the transmission and distribution systems as well as flexibility procurement, and service conflict avoidance.

RETROFIT SCENARIOS

We initially quantified the cost of retrofitting all DER not or partially monitored, as well as the benefits that full visibility would unlock. This exercise was repeated for varying levels of minimum DER capacity to retrofit from 0kW to 1MW, which affect both cost and benefits. Scenario that have been studied are:

- Retrofit Scenario 1 (SC1): retrofit everything 0kW and above;
- Retrofit Scenario 2 (SC2): retrofit everything 200kW and above;
- Retrofit Scenario 3 (SC3): retrofit everything 500kW and above;
- Retrofit Scenario 4 (SC4): retrofit everything 1MW and above.

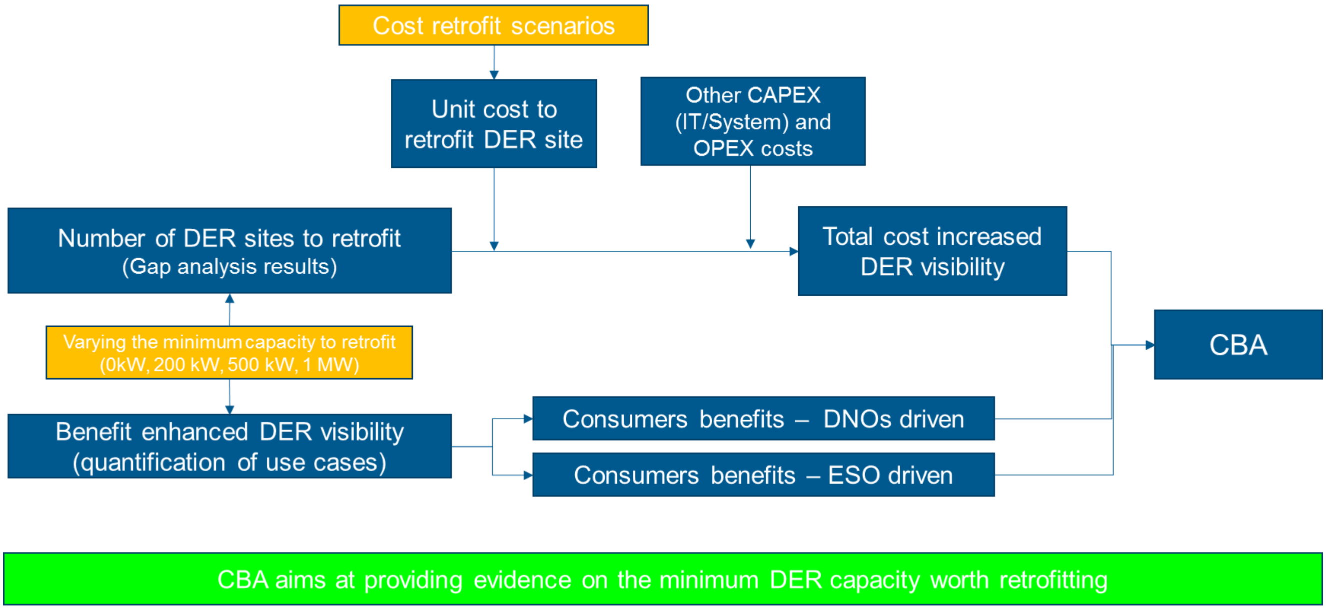


Figure 1: CBA approach

4.3. DER in scope

The boundary of the DER included into WS1B P6 scope is summarized below:

- **DER Type**: generation sites. Demand has been excluded from the scope.
- **Voltage Level**: Distributed connected generation sites, connected to EHV and HV voltage levels. LV sites have been excluded from the scope.
- **DER Capacity**: We initially considered anything (>0MW) connected from HV to EHV. Minimum capacity is going to be advised by the CBA results.

- **DER Connection Date**: applies retrospectively to existing DERs. Generators connected after April 2019 are required to have monitoring and controlling capability in place as per by EREC G99.

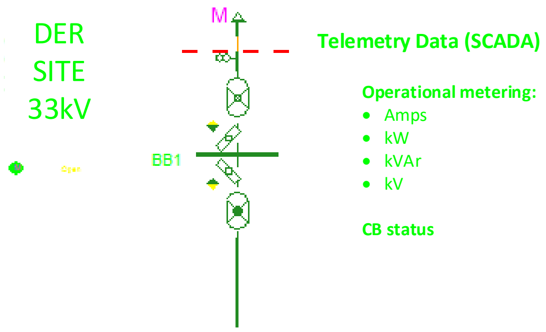


Figure 2: data points in scope

4.4. Data Points in Scope

The CBA has been carried out specifically looking at DER Operational Metering data from the DER PoC, which refers to real-time telemetry SCADA feeding to the DNO's Distribution Management System (DMS) that can then be fed into different platform and application via e.g. ICCP such as ESO EMS and ANM.

Data points in scope are summarized in

Table 2

Table 2: Data Points in Scope

Data Point	Description
Amps	Measured Current at point of connection
Volts	Measured Voltage at the point of connection
MW	Measured Active Power at point of connection
MVAR	Measured Reactive Power at point of connection
Breaker status	Indication of the open/ close status of the isolating switchgear

For clarity, it does not refer to customer metering used for settlement bur rather DNOs metering.

4.5. What's not in scope

4.5.1. EMBEDDED SITES

Is situations where DGs are connected behind the meter supplying local demand (e.g. gensets supplying local industrial load), the operational metering at the POC may not be representative the true generation output as generation output could be masked by local load.

To have visibility of the individual generation unit rather than the net site load, metering would need to be installed at the generation breaker behind the meter rather than at the incoming breaker.

Visibility of embedded sites is excluded from the scope; however, the product team recognizes that having visibility of embedded generation sites would be beneficial for better management of the network.

4.5.2. SCADA alternatives

The standard approach DNOs use to get DER operational metering data is by installing own equipment which includes CT/VT, relays, a Remote Terminal Unit (RTU), and communication infrastructure to be able to transmit the data points via SCADA to the DNO Distribution Management System (DMS).

There are alternative and possibly cheaper approaches to the traditional telemetry data transfer via SCADA, which involve getting measurement from the customer meter and transferring the data via WebAPI (application Programming interface).

There is a general view that currently DNOs would not feed customer data into the control system via API for the reasons below:

- As the data come from customers' equipment, DNOs wouldn't have visibility on the quality/correctness of the data and hence wouldn't use these data for control system applications such as automation programmes to restore supplies.
- Currently, if there is any issue with DER telemetry data (e.g. bad quality), there are service-level agreements (SLAs) in place which define the issues resolution time for all the components that may be affected (RTU issues/comms issues etc). There is no such thing for measurement coming from customer equipment.
- SCADA is specifically designed not just to fetch an analogue value, but also detect the loss of it. Most APIs can't do that so to have an equivalent function, DNOs would need to do built extra functionalities (extra cost).

For the reasons above, we have not considered the option of getting operational metering data from the customers meter via API for sites where DNOs don't have any visibility over. We do recognize the value of WebAPI as it is most economical compared to the traditional SCADA approach. However detailed assessment on the level of reliability, accuracy and redundancy of the WebAPi solution need to be carried out, as well as policies and standard will need to be developed.

The recommendation from the product team is to consider API for the sites that CBA shows is not worth retrofitting (e.g <1MW).

5. DER Visibility Gap Analysis

5.1. Gap analysis scope

We have carried out a DER visibility gap analysis across all licence areas to assess the level of visibility DNOs currently have over EHV and HV generation sites. The investigation looked into the following:

- **Monitored vs un-monitored sites (level 1 analysis)** : The portion of sites and capacity over which DNOs have visibility over through SCADA, versus the sites where DNOs are not currently getting any real time measurement, hence 'invisible' from DNOs point of view. Level 1 Gap analysis results are available in Table 5
- **Full Visibility vs Partial Visibility (level 2)** among the sites that are currently monitored, we have investigated the portion of sites over which DNOs have full visibility (P, Q, V, I and open/close indication) versus the sites with partial visibility (e.g. only Amps). Level 2 gap analysis results are available in Table 7.
- **Un-monitored sites breakdown**: we have then carried out an additional investigation for the sites that are not monitored, looking at the voltage level and capacity range they fall into (0-200 kW, 200- 500 kW, 500kW – 1MW, 1MW-10 MW, or above 10 MW). Level 1 capacity breakdown results are available in Table 6.

Level 1 and Level 2 gap analysis results have bene used to carry out **CBA to enhancing DER visibility** and monitoring.

A further assessment that we think could give valuable insights, although excluded from the scope of the product, is to look at the current level of measurement accuracy and resolution of data capture from generation sites which we have full visibility over, installed prior to e.g. EREC G99 and EREC G59.

We expect there to be a large number of legacy generators, with low accuracy and resolution of data capture due to higher CT/VT classes (lower accuracy) than the minimum standard required for new installation, low analogue to digital converter and large measurement dead-banding in the RTU. Level 3 Gap analysis results could be used for a **CBA to enhance accuracy** of operational metering from legacy sites.

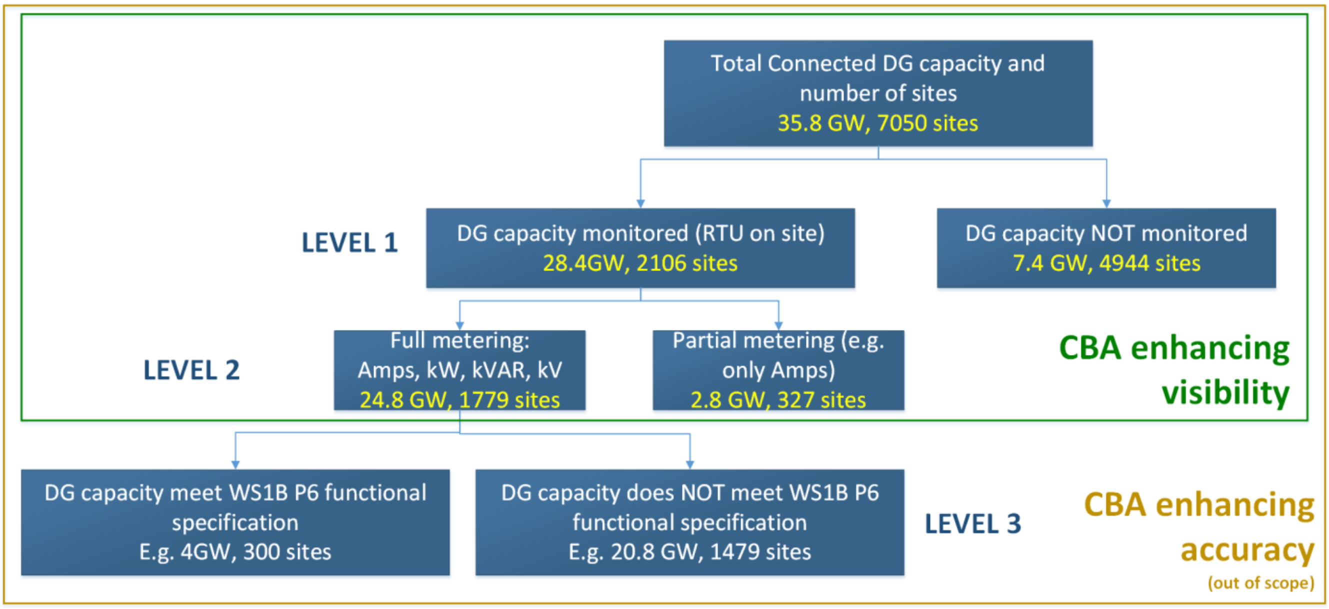


Figure 3: Gap Analysis approach

5.2. Gap Analysis Alignment

Different DNOs have used various databases to produce gap analysis results including ECR, internal DG databases and extracts from the operational DMS system. To ensure we were carrying out a like for like' comparison we aligned on the points below:

- Full monitoring is defined as P, Q, I & V and Open and Close indication.
- Capacity refers to export capacity rather than installed capacity.
- All DER capacity size from EHV and HV (including 1 MW and below) has been included, to have a full picture of the unmonitored capacity/sites on the HV.

5.3. Gap Analysis Results

Having carried out analysis of, we have identified that there is a considerable gap in monitoring of DGs connected to DNOs network across GB:

- DNOs lack visibility of around 20% of the total export generation capacity corresponding to 7.4 GW of generation, out of the 35.8 GW connected on DNOs network across GB.
- Most of the invisible generation capacity is connected to the HV network: out of the 7.4 GW of un-monitored capacity, 1.5 GW are connected to the EHV network and 5.9 GW on the HV network.
- There is a considerable gap in monitoring on the HV networks: out of the total 7.6 GW of generation capacity connected to the HV network across GB, 1.6GW are monitored and 5.9GW are not, corresponding to ~80% of the total.
- Generators on the EHV network are considerably more monitored than in the EHV: out of 28.2 GW of capacity, 1.5GW is not monitored, corresponding to 5% of the total.

Table 3: Level 1 Gap analysis Summary

DNO TOTALS	TOTAL (EHV + HV)	EHV	HV
Total Capacity [GW]	35. 8GW	28.2 GW	7.6 GW
Monitored Capacity [GW]	28.4 GW	26.7 GW	1.6 GW
Un-monitored capacity [GW]	7.4 GW	1.5 GW	5.9 GW
Unmonitored Capacity [% of total]	20.6%	5%	78%

The additional considerations can be made looking at the breakdown of the unmonitored sites:

- The total 7.4 GW on unmonitored capacity is mostly made up of generators in the 1-10MW capacity bracket (79%)
- Out of the 4944 unmonitored sites making up the 7.4 GW of capacity, 1894 are in the 0-200kW capacity bracket, with a combined capacity of 190MW (3% of the total unmonitored capacity). Whereas the sites in the 1-10MW capacity bracket are 1297 and have a combined capacity of 5.9GW making up the 79% of the total.

Table 4: - Gap analysis Level 1 Summary – unmonitored sites breakdown

Unmonitored sites	Sites/capacity not monitored	0-200 kW	200-500 kW	500 kW- 1 MW	1-10 MW	>10 MW
Number of Sites	4944	1894	1055	630	1297	68
Total Capacity	7.4 GW	0.19 GW	0.32 GW	0.34 GW	5.9 GW	0.68 GW
% of capacity		3%	4%	5%	79%	9%

Table 5: Operational Metering Gap Analysis results – Level1 (monitored vs unmonitored)

DNO	VOLTAGE LEVEL [kV]	NUMBER OF SITES	CAPACITY [MW]	Sites MONITORED (RTU on site)		Sites NOT MONITORED			
				Number of Sites	Capacity [MW]	Un-monitored sites	% of un-monitored sites	Un-monitored capacity [MW]	% of un-monitored capacity
UKPN	132	32	3319	**32**	3319	0	0.0%	0	0%
	33	214	3431	**213**	3417	1	0.5%	13.4	0%
	11	1791	1954	**41**	437	1750	97.7%	1516.8	78%
ENW	132	11	948	11	769	0	0.0%	179	19%
	33	61	938	60	900	1	1.6%	38	4%
	11 / 6.6	355	520	2	14	353	99.4%	506	97%
SPEN	132	10	624	**7**	387	3	30.0%	237	38%
	33	172	3285	**159**	2998	13	7.6%	287	9%
	11	370	741	**36**	218.6	334	90.3%	522	70%
NPG	132	13	1013	13	1013	0	0.0%	0	0%
	66/33	98	2108	86	1822	12	12.2%	286	14%
	20/11/6.6	435	1148	85	405	350	80.5%	743	65%
WPD	132	32	1712	31	1702	1	3.1%	10	1%
	66/33	489	5055	466	4650	23	4.7%	404.6	8%
	11/6.6	1338	2105	88	343.2	1250	93.4%	1762	84%
SSEN	132	12	947	12	947	0	0.0%	0	0%
	33/22	592	4866	592	4865	0	0.0%	0	0%
	11/6.6/3.3	1025	1086	172	209	853	83.2%	876.5	81%
TOTALS		**7050**	**35. 8GW**	**2106**	**28.4 GW**	**4944**		**7.4 GW**	

Table 6: Operational Metering Gap Analysis results – Level1, breakdown of un-monitored sites.

DNO	VOLTAGE LEVEL [kV]	NUMBER OF SITES	Number of un monitored Sites	BREAKDOWN OF UN-MONITORED SITES				
				100-200 KW	200-500 kW	500 kW- 1 MW	1-10 MW	>10 MW
UKPN	132	32	0	0	0	0	0	0
	33	214	1	0	0	0	0	1
	11	1791	1750	1188	145	121	296	0
ENW	132	11	0	0	0	0	0	0
	33	61	1	0	0	0	5	1
	11 / 6.6	355	353	89	64	79	121	0
SPEN	132	10	3	0	0	0	0	3
	33	172	13	0	0	0	10	3
	11	370	334	21	137	42	127	7
NPG	132	13	0	0	0	0	0	0
	66/33	98	12	0	0	0	3	9
	20/11/6.6	435	350	34	131	50	125	10
WPD	132	32	1	0	0	0	0	1
	66/33	489	23	0	0	0	6	17
	11/6.6	1338	1250	242	421	169	409	9
SSEN	132	12	0	0	0	0	0	0
	33/22	592	0	0	0	0	0	0
	11/6.6/3.3	1025	853	320	157	169	200	7
TOTALS		**7050**	**4944**	**1899**	**1057**	**630**	**1302**	**68**

Table 7: Operational Metering Gap Analysis results – Level 2 (Full metering vs partial metering)

	VOLTAGE LEVEL [kV]	NUMBER OF MONITORED SITES	MONITORED SITES & FULL metering		MONITORED SITES & PARTIAL metering
			Number of sites	Percentage of monitored	**Number of sites**
UKPN	132	**32**	29	91%	3
	33	**213**	208	98%	4
	11	**41**	23	56%	18
ENW	132	11	10	91%	1
	33	60	55	90%	5
	11 / 6.6	2	2	100%	0
SPEN	132	**7**	7	98%	0
	33	**159**	143	90%	16
	11	**36**	14	40%	22
NPG	132	13	7	54%	6
	66/33	86	78	91%	8
	20/11/6.6	85	27	32%	58
WPD	132	31	30	97%	1
	66/33	466	460	99%	6
	11/6.6	88	71	81%	17
SSEN	132	12	12	98%	0
	33/22	592	533	90%	59
	11/6.6/3.3	172	69	40%	103
TOTALS		**2106**	**1177**	**2106**	**327**

6. Costs to Enhance DER Visibility and Monitoring

We have carried out 4 different CBA studies, varying the minimum capacity to retrofit from 0kW to 1MW. Scenario 1 looks are retrofitting all DGs on the HV. EREC G99 set minimum HV connected generator to require monitoring at is 800W (0.8kW), which basically means anything DNO have connected on the HV; going forward we will refer to it as 0kW (of unmonitored capacity).

Scenarios 2, 3 and 4 looks are retrofitting everything above 200kW, 500kW and 1MW respectively.

The minimum DG capacity to retrofit, affects the total number of sites to retrofit an ultimately drives cost. It also affects the total level of visibility reached after retrofitting and the total unmonitored capacity left. Scenario one would everything and reach 100% visibility, this number goes down based on the scenario considered, to a minimum of 97.6% in scenario 4, after retrofitting everything larger than 1MW, as shown in Table 8 below.

Table 8: CBA Scenarios

Scenario	Scenario description	Level of Visibility (after retrofitting)	Total Unmonitored Capacity [MW] (after retrofitting)
SC1	Retrofit all DER with capacity 0.8kW and above	100%	0MW
SC2	Retrofit all DER with capacity 200 kW and above	99.5%	189 MW
SC3	Retrofit all DER with capacity 500 kW and above	98.6%	506 MW
SC4	Retrofit all DER with capacity 1 MW and above	97.6%	853 MW

6.1. DER Operational metering Cost

The cost of retrofitting generation sites to get real time monitoring varies considerably based on the equipment already installed on site and primarily on the availability of metering unit, transducer, the type of RTU installed, the age/state of the switchgear, the availability of comms etc, which would require a site-by-site investigation to assess site specific retrofit cost.

The approach we have taken is to create retrofit cost scenarios for each voltage level, which capture all the likely scenarios DNOs would come across to retrofit DG sites and associated cost. Cost is a combination of material cost and indirect cost as shown below:

a) Material cost (as applicable depending on retrofit requirement):

- Transducer installation
- Metering unit (CT/VT)
- Switchgear replacement with metering unit
- RTU installation/replacement & Batt Charger
- SCADA Comms (cellular/satellite/fibre/radio/copper)

b) Indirect cost:

- Project time
- Design
- Installation
- Commissioning (SAP engineer etc)

Material cost is mostly standard across DNOs , with some variance in the current practice DNOs use on DER monitoring, including the communication type (fibre, radio, cellular, satellite ect). We captured a cost bucket that would cover retrofit practices from all DNOs.

We have identified 3 main EHV and HV retrofit scenarios, summarized below: each of the 3 scenarios also varies depending on whether there is a RTU and communication infrastructure installed on site.

- **Case A: metering available, place a transducer in parallel**
  - A1: Modern RTU installed/comms available
  - A2: Modern RTU NOT installed/comms NOT available
- **Case B: New metering unit installation required**
  - A1: Modern RTU installed/comms available
  - A2: Modern RTU NOT installed/comms NOT available
- **Case C: Switchgear replacement with new metering unit**
  - A1: Modern RTU installed/comms available
  - A2: Modern RTU NOT installed/comms NOT available

6.1.1. RETROFIT HV DER CONNECTONS

Findings from the Gap analysis showed that 80% of the unmonitored 7.4 GW of generation capacity across GB distribution network is connected to the HV corresponding to 5.9GW. Most of the sites to be retrofit will fall into the cost described in this section.

Description of the 3 HV retrofit cost scenario is described below and summarized in Figure 5 and Table 9.

CASE A HV: METERING AVAILABLE, PLACE A TRANSDUCER IN PARALLEL

In this option, generators are retrospectively fitted with a transducer in parallel with the on-site metering (CT/VT), which either refers to DNOs metering if available, or customer metering, if current DNOs practices allow to do so.

As part of WS1B P6 deliverable C, functional specifications, it was identified that DNOs mostly use metering CT over protection CT for HV generators, whereas on the EHV DNOs would only use protection CT, so the option of connecting to customer CT has only been considered for HV sites.

Placing a transducer in parallel to existing metering unit, would allow to retrieve Current, Voltage, Active and Reactive Power measurements from the generators PoC. This can be done without a customer outage, unless there are complications with the wiring.

Figure 4 below shows Case A HV electrical design whereby a transducer is fit in parallel to DNO or customer CT/VT breaking into protection circuits.

There are some cases where this retrofit option cannot be carried out, which include:

- If placing a transducer in parallel would exceed the burden on the customer's metering devices;
- If the DNO substation is not located in the proximity of the customer substation, which means considerable distance between the meter and the customer CTs. This could over burden the meter and distort the measurements;
- If the customer's CT/VT are not easily accessible;
- If the metering unit installed is old, which can potentially have granularity issues leading to inaccurate measurements

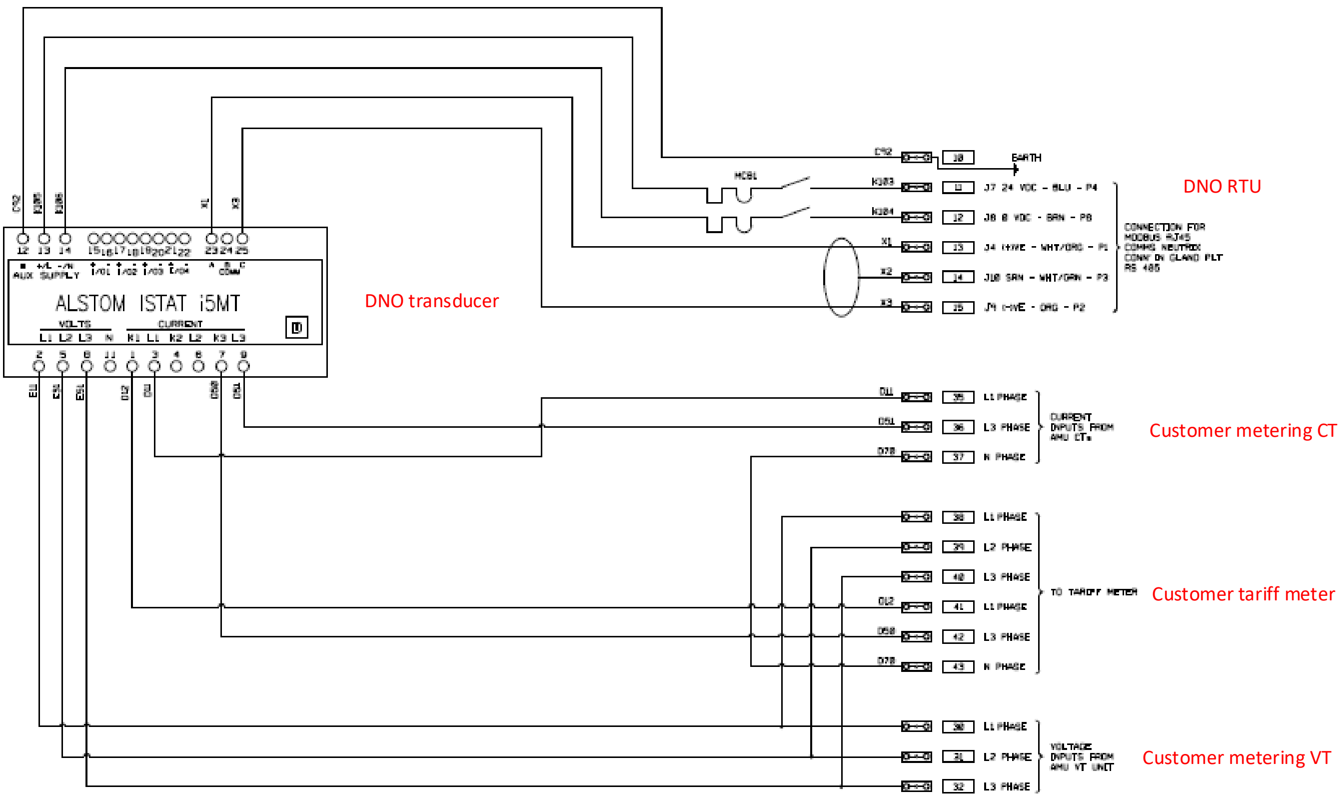


Figure 4: Case A HV – fitting transducer in parallel

Direct and indirect cost of retrofitting a transducer in parallel is approximately £3k/site

If for the reasons above a transducer in parallel cannot be installed, alternative options are summarized below.

CASE B HV: NEW METERING UNIT INSTALLATION

This captures the situation where either there is no DNO metering unit installed or the metering unit needs to be replaced to provide P&Q measurements, and where the switchgear can accommodate the new measurements.

This requires the installation of HV metering unit which based on direct and indirect cost is approximately £18k/site.

CASE C HV: SWITGHGEAR REPLACEMENT WITH NEW METERING UNIT

This captures the situation where the metering unit is not available or an old metering unit needs to be replaced to get additional measurements, and switchgear cannot accommodate the new measurements. This requires HV switchgear replacement which based on direct and indirect cost is approximately £28k/site.

RTU and SCADA for HV installation

The below is applicable for the 3 HV retrofit scenarios [A/B/C]

- **[A/B/C].1 HV RTU/Comms available**
  If a modern RTU (Gemini3, Calliston NX) is already installed on site and if SCADA is already commissioned, no additional RTU and comms cost have been considered.

- **[A/B/C].2 HV RTU/Comms NOT available**
  If there is a legacy RTU on site (Gemini1, Gemini2) which cannot accommodate additional measurements from the transducer, or if there is no RTU on site and SCADA is not commissioned yet, a new modern RTU will need to be installed and comms commissioned, with an approximate additional cost (direct and indirect) of £12k/site.
  Each DNO has different standard designs and arrangements for operational communications at DER sites at different voltage level. The most likely comms solution for HV sites is GPRS/3G/4G (cellular) or satellite which require a modem installation or an antenna. In the costing, we have assumed availability of cellular comms and reasonable distance from cellular tower.

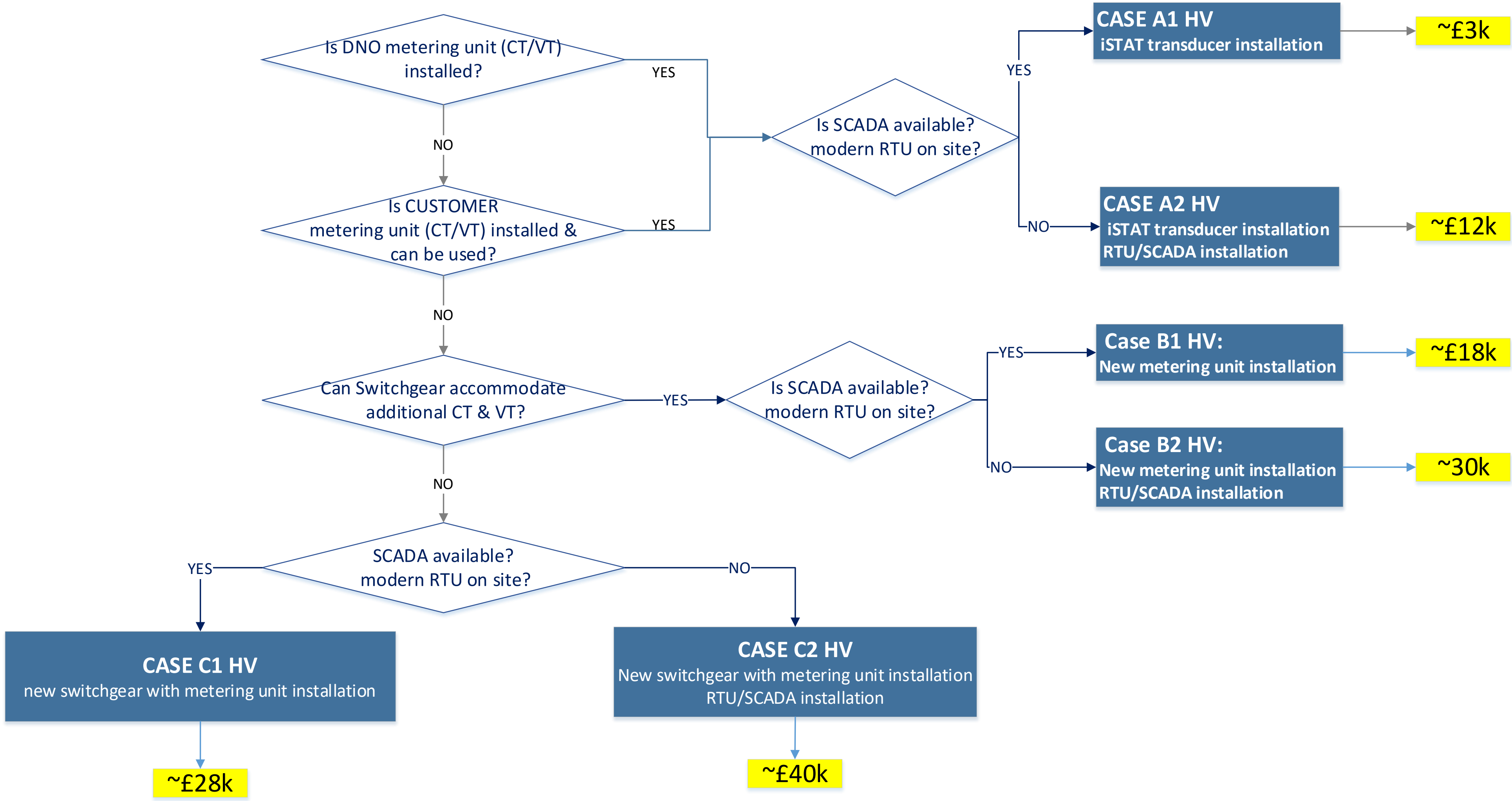


Figure 5: HV DER retrofit cost scenarios

Table 9: HV DER retrofit cost scenarios

Retrofit Case	Scope of Retro fitting HV DER connections	Approx. Cost	New Equipment	% of sites
Case A1 HV	Metering unit (either DNO or customer) installed and accessible RTU and SCADA available	£3K	Project Time iSTAT transducer + cables	Best case: 40% of sites Worst Case: 20% of sites
Case A2 HV	Metering unit (either DNO or customer) installed and accessible RTU and SCADA not available	£12K	As above + RTU installation Cellular Comms commissioning	Best case: 30% of sites Worst Case: 10% of sites
Case B1HV	New Metering unit to be installed or existing one to be replaced to provide P&Q Switchgear can accommodate additional measurement RTU and SCADA available	£18K	Project time Old metering units supplied and refitted	Best case: 15% of sites Worst Case: 10% of sites
Case B2 HV	New Metering unit to be installed or existing one to be replaced to provide P&Q Switchgear can accommodate additional measurement RTU and SCADA not available	£30K	As above + RTU installation SCADA commissioning	Best case: 5% of sites Worst Case: 20% of sites
Case C1 HV	Metering Unit not installed Switchgear cannot accommodate additional VT & CT measurements RTU and SCADA available	£28K	Project time New switchgear with metering unit	Best case: 5% of sites Worst Case: 20% of sites
Case C2 HV	Metering Unit not installed Switchgear cannot accommodate additional VT & CT measurements RTU and SCADA NOT available	£40K	As above + RTU installation SCADA commissioning	Best case: 5% of sites Worst Case: 20% of sites

6.1.2. RETROFIT EHV DER CONNECTONS

Findings from the Gap Analysis showed that out of the 28.2 GW of generation connected to the EHV network, 95% of it is currently monitored, and 5% of it, corresponding to 1.5 GW of capacity (54 sites) is not. Description of the three retrofit cost scenario that applies to the EHV are described below and summarized in Figure 6 and Table 10.

The cost to retrofit EHV varies significantly more than for the HV situation, we made the following assumptions:

- SCADA RTU & battery charging systems are the same for both 132 & 33kV connections
- Switchgear assumes simple single AIS CB arrangement
- Assumes LV supply is available locally from the network or the customer
- Comms is simple & no planning permission required

CASE A EHV: DNO METERING UNIT AVAILABLE, PLACE A TRANSDUCER IN PARALLEL

This captures the situation where DNO metering unit (CT/VT) already exists and additional measurements can be obtained by installing a transducer breaking into protection circuits if required. The cost is approximately £6K.

CASE B EHV: NEW METERING UNIT INSTALLATION

This captures the situation where CT/VT needs to be installed or replaced and the switchgear can accommodate the additional measurements (assumed AIS and not GIS, which are likely to already have monitoring).

The cost of 132kV CT/VT installation is approximately £20K/phase so £60k for a new metering unit, plus £5k for transducer installation. Considering direct and indirect cost, the total cost to get P, Q, V, I form a 132kV generation site is approximately £85K. For 33kV sites the cost considered in approximately £65K

CASE C EHV: SWITCHGEAR REPLACEMENT WITH NEW METERING UNIT

This captures the situation where the switchgear cannot accommodate the new measurement and needs replacing. The cost is very subjective to plant type, and physical space. 33kV sites may require full board change with new set of CT/VT, which we have estimated at £120K/site. It has been assumed that for 132kV sites the switchgear does not need replacing.

RTU AND SCADA FOR HV INSTALLATION

The below is applicable for the 3 EHV retrofit scenarios [A/B/C]

- **[A/B/C].1 EHV RTU/Comms available**
  If a modern Type D RTU is already installed on site and SCADA is already commissioned, no additional RTU and comms cost have been considered.

- **[A/B/C].2 EHV RTU/Comms NOT available**
  If there is a legacy RTU which cannot accommodate additional measurements, or if there is no RTU on site a new modern RTU will need to be installed.
  Each DNO has different standard designs and arrangements for operational communications at DER sites at different voltage level. DNO practices for EHV sites spans from cellular, satellite, fibre, copper and radio, each one with different level of cost, which for physical comms (e.g. fibre) is also affected by the distance from the site to DNO substation. Some DNO uses double comms e.g. cellular and satellite, other use single physical communication infrastructure. The cost we considered is assumes that comms is simple & no planning permission required.
  Approximate additional cost (direct and indirect) for sites with no RTU and SCADA in place is £30k/site.

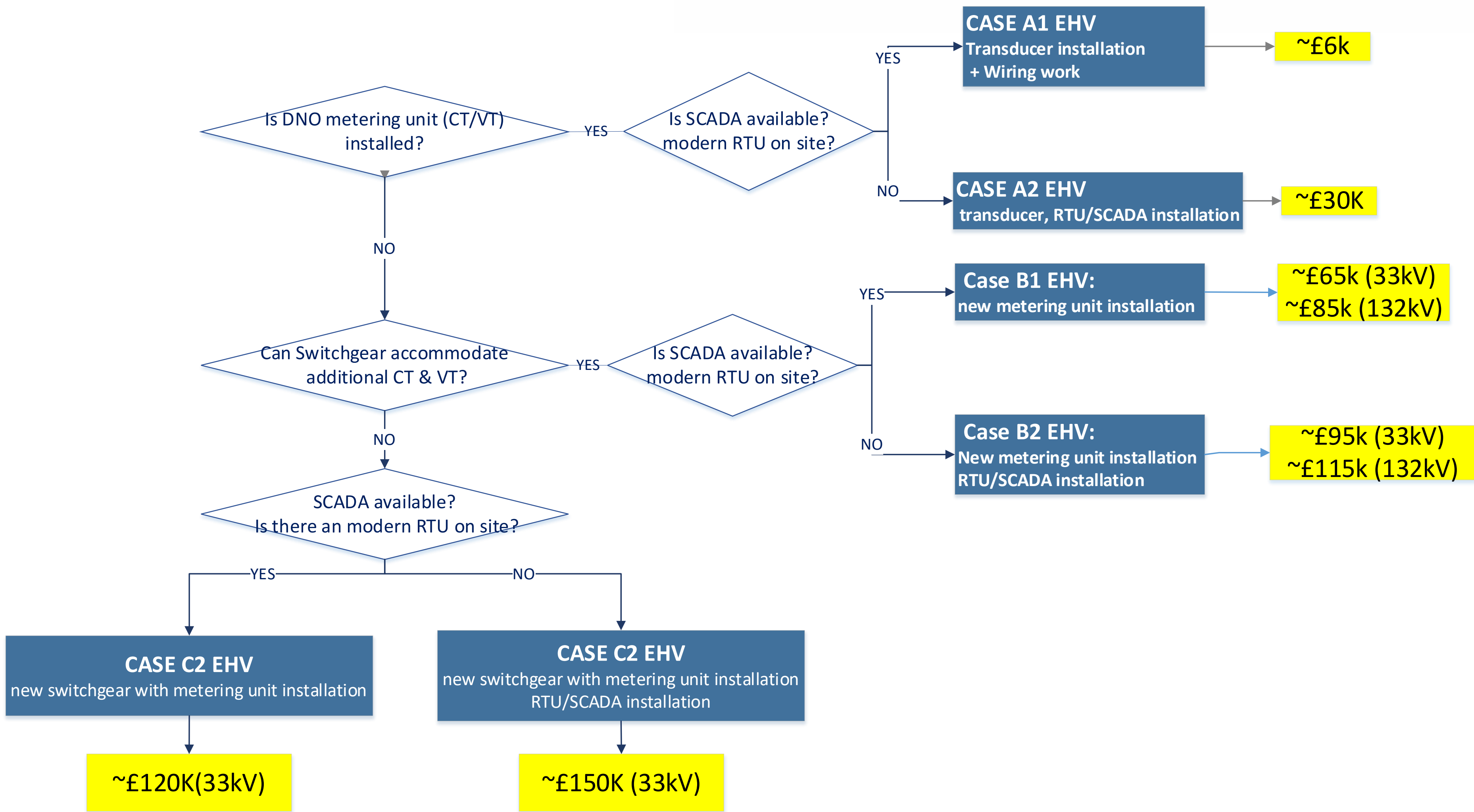


Figure 6: EHV DER retrofit scenarios

Table 10: EHV DER retrofit scenarios

	Scope of Retro fitting 132 & 33kV DER connections	33kV Approx. Cost	132kV Approx. Cost	Included in the cost	
Case A1 EHV	Metering unit installed CT & VT exists and additional measurements can be obtained breaking into protection circuits RTU and SCADA available	£6k	£6K	Project time Metering scheme required Transducer installation Design, commissioning	Best case: 40% of sites Worst Case: 20% of sites
Case A2 EHV	Metering unit installed CT & VT exists and additional measurements can be obtained breaking into protection circuits RTU and SCADA Not available	~£30K	~£30K	As above + RTU/battery installation and Comms SCADA commissioning	Best case: 30% of sites Worst Case: 10% of sites
Case B1 EHV	Metering unit to be replaced to provide P&Q Switchgear can accommodate additional measurements RTU and SCADA available	~£65K	~85K	Project time New metering unit/ adding just CT & VT (only AIS) Design, installation, commissioning	Best case: 15% of sites Worst Case: 10% of sites
Case B2 EHV	Metering unit to be replaced to provide P&Q Switchgear can accommodate additional measurements RTU and SCADA not available	~£95K	~£115K	As above + RTU/battery installation and Comms SCADA commissioning	Best case: 10% of sites Worst Case: 40% of sites
Case C1 EHV	Metering Unit not installed or to be replaced Where switchgear cannot accommodate additional VT & CT measurements SCADA NOT available	~£120K	n/a	Project time New switchgear Metering scheme required Design, installation, commissioning	Best case: 3% of sites Worst Case: 10% of sites:
Case C2 EHV	Metering Unit not installed or to be replaced Switchgear cannot accommodate additional VT & CT measurements SCADA available	~£150K	n/a	As above + RTU/battery installation and Comms SCADA commissioning	Best case: 2% of sites Worst Case: 10% of sites

6.1.3. RETROFIT COST RESULTS

Based on the number of sites that are currently either not monitored or partially monitored, and on the unit cost to retrofit these sites, we have calculated the overall capital cost required to enhance visibility for the four retrofit scenarios. Results are captured in Table 11 below.

"Best case" give an optimistic view on the total cost of retrofitting, considering lower number of sites requiring more expensive retrofit work (e.g. switchgear replacement). "Worst case" give a pessimistic view on the total retrofit cost, based on higher number of sites requiring more expensive retrofit work. The percentages of sites falling in each of the scenario is summarized in Table 9 and Table 10.

Table 11: Retrofit cost results

CBA scenario	Minimum Capacity to retrofit	Number of sites to retrofit	Retrofit Cost BEST case	Retrofit Cost WORST CASE
SC1	> 0kW	5265	£69.5 M	£131.2 M
SC2	> 200 kW	3373	£46.1 M	£87.3 M
SC3	> 500 kW	2316	£33 M	£62.8 M
SC4	> 1MW	1686	£25.2 M	£41.5 M

6.2. Other CAPEX Cost (IT and System Cost)

Beside the cost of getting the measurement at DER site which includes metering unit, relays etc, and the cost of transmitting the measurements to the DNO DMS system, which includes RTU and comms , there are other system cost required to enable DNO to process and store data. The additional number of sites on SCADA will require:

- Additional number of Front End Processor (FEPs)
- Additional storage requirement to store data into historian.

6.2.1. FEPs Cost

FEPs is the component which deals with SCADA communication out to field devices and integrates to the DMS. A pair of FEPs (£30k) can accommodate approximately 500 new sites. The number of FEPs required will depend on the number of new sites on SCADA and hence on the scenario considered. FEPs cost is summarized in Table 12 below.

Table 12: IT cost/ FEPs

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	Number of FEPS required	FEPs cost
SC1	> 0kW	5265	11	£158k
SC2	> 200 kW	3373	7	£101k
SC3	> 500 kW	2316	5	£70k
SC4	> 1MW kW	1686	3	£51k

6.2.2. STORAGE COST

Additional DER on SCADA also calls for additional storage space requirements to store historical operational metering data.

Based on average 50 data points per site (P, Q, V, I , CB, T, 30 min Max, Mins, average etc) we have estimated that the additional storage cost per site will amount to £9.5 /site, which includes storing data points both in the DMS system (for each datacentre) and in the operational historian, as well as a creating backup for each of these data as DNO common practice. Costs are based on £1250/1000GB of memory and 425 MB/site. Results based on retrofit scenario are summarized in Table 13 below.

Table 13: IT cost/ Storage

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	Storage cost
SC1	> 0kW	5265	£50 K
SC2	> 200 kW	3373	£32 K
SC3	> 500 kW	2316	£22 K
SC4	> 1MW kW	1686	£16 K

6.2.3. Communication Cost (from DMS to other applications)

The cost of data transfer between DNOs and ESO control centres via ICCP or to other applications (e.g. third party platforms) has not been included in the CAPEX cost as ICCP is being rolled out by ESO and DNOs out as part of different projects (i.e. RDP MW dispatch) and the capacity released will be sufficient for the additional volumes of DG considered in this assessment.

6.3. OPEX COST

Beside capital expenditure of the physical infrastructure required to capture, transmit and store DER data points, enhanced DER visibility has an impact on recurring operational cost. We have identified the four categories below:

- Fault resolutions on site
- Yearly Cellular comms contract
- RTU Battery replacement
- Data storage

6.3.1. OPEX: Faults resolution on site

This covers the cost DNOs would incur into, due to faults on DER sites that require intervention from operational telecom engineer. We have estimated a cost of £50/site/year which includes:

- The annual cost for the administration of the all the units, diagnosing faults remotely, and raise fault work requests;
- The annual field team costs – includes labour / mileages etc;
- Support contracts with RTU suppliers.

Operational expenditure related to faults resolution on site is summarize in Table 14 below.

Table 14: OPEX/ Issues resolution on site

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	Faults resolution on site
SC1	> 0kW	5265	£263 K/year
SC2	> 200 kW	3373	£169 K /year
SC3	> 500 kW	2316	£116 K /year
SC4	> 1MW	1686	£84 K/year

6.3.2. OPEX: RTU battery replacement cost

RTUs require battery for standby applications, which have 10 years replacement cycle.

The cost for replacing battery is £4.5k for EHV sites and £200 for HV sites, which we have annualized to £450/site/year and £20/site/year for EHV and HV sites respectively. Operational expenditure related to battery replacement is summarized in Table 15 below.

Table 15: OPEX/Battery replacement

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	Sites issue resolution/ Ops telecom
SC1	> 0kW	5265	£173 K/year
SC2	> 200 kW	3373	£135 K/year
SC3	> 500 kW	2316	£114 K /year
SC4	> 1MW	1686	£101 K /year

6.3.3. OPEX: Cellular comms per year

Comms operational cost varies considerably based on the comms type used by DNOs. As most of the sites that lack visibility are HV sites, cellular comms is likely going to be the use which we have estimated to be ~ £100/site/year.

Operational expenditure related to comms cost is summarized in Table 16 below.

Table 16: OPEX/ Comms cost

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	Comms cost
SC1	> 0kW	5265	£526 K/year
SC2	> 200 kW	3373	£337 K/year
SC3	> 500 kW	2316	£232 K/year
SC4	> 1MW	1686	£169 K/year

6.3.4. OPEX: Data Storage

Beside the additional storage space required considered in the capital expenditure, there is a yearly cost to store data into the historian (£1/data points/year). Considering a range of data points from 10 to 50, Operational expenditure related to data storage cost are estimated as in Table 17.

Table 17: OPEX/ data storage

CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	BEST CASE	WORST CASE
SC1	> 0kW	5265	£53 K/year	£263K/year
SC2	> 200 kW	3373	£34K/year	£169K/year
SC3	> 500 kW	2316	£23 K/year	£115K/year
SC4	> 1MW	1686	£17 K/year	£84K/year

7. Benefits enhanced DER Visibility and monitoring

This section provides a description and quantification of ESO and DNOs benefits that would be unlocked by the enhanced DER visibility and monitoring.

7.1. Consumers benefits - ESO driven

Currently the ESO only has limited operational visibility of distributed generation. This is due to a number of reasons ranging from the absence of operational metering to internal system changes needed to allow the ESO to view and interpret greater volumes of DG.

There are significant benefits to the ESO of greater operational visibility of DG. The table below, lists ten ESO use cases with example of the benefit that can be realised.

In this work the ESO has looked at the benefits that can be derived from retrospective application of monitoring equipment to existing connected DG. Broader improvements to facilitate operational visibility of DG, including systems and comms infrastructure would be sufficient to accommodate these additional DG. The ESO is developing its thinking in these areas in co-ordination with this work. To this end the table below also identifies those quantifiable benefits relevant to the retrospective application of monitoring equipment to existing connected DG.

It should be noted that the scope of the work and proposed monitoring standard precludes the benefits of some use cases (for example participation in many ESO balancing services markets). The ESO has also carried out its assessment against current industry rules and frameworks.

Table 188: ESO Use Case benefits

Use case	Quantifiable benefit
Ancillary and balancing service provision (Use Case 3)	Facilitates market access for increasing volumes of DG to thermal congestion management markets through initiatives such as RDPs.
System restoration (Use Case 4)	Utilising distributed generation to restore power following a black start event
Capacity Mechanism (CM) planning (Use Case 5)	None identified
Whole system co-ordination of services (Use Case 6)	None identified
System resilience (Use Case 7)	Reducing impact and frequency of high impact low probability events
Operational co-ordination (Use Case 8)	Improving real time assessment of system behaviour and real time actions
Improved network access planning (Use Case 9)	Improving operational planning of the power system and need for constraint mitigations
Improved long Long term system development (Use Case 10)	Improving long-term understanding of power system behaviour and requirements for additional system needs
Forecasting (Use Case 11)	None identified
New market opportunities (Use Case 14)	None identified

7.1.1. Quantification of benefits related to greater operational DER visibility

The ESO has applied differing methodologies for each quantifiable benefit. In all cases it has first considered the impact of greater DG visibility to the ESO as a whole including those generators who already have monitoring equipment but whose operational data is not accessible to the ESO. It has then proportioned the benefits to reflect the volume of generation being considered in the ENA work. Where appropriate it has considered the four retrofit scenarios presented in Table 8.

A. Benefits arising from reduced thermal congestion costs

Assessment of the four high level use cases shown in Table 19 is based on a common assessment of future thermal constraint costs, the ESO's published Forward Look at Constraints[5]. This paper has produced a forward-looking view of thermal constraints across the GB transmission system using the four 2020 FES backgrounds.

In use case 3 'Ancillary and balancing service provision' the ESO has considered that greater DER visibility could bring new parties to thermal constraint markets increasing their liquidity and therefore unit cost. Given the inherent uncertainties in predicting market behaviour, the ESO has considered a modest 1% decrease due to greater operational visibility of all DG. This has then been proportioned in this assessment to 0.25% reflecting the proportion of DG that being considered by the ENA work. In this use case the ESO has only considered retrofit scenario 4 (DG capacity >1MW) assuming market entry for parties below 1MW would not be feasible at this time.

The remaining three use cases shown in Table 19 below have been assessed via a common methodology as all are linked to improvements to the ESO's understanding of system behaviour (see descriptions in Table 18 above). This impacts the constraint volumes forecast on the system in different timescales allowing the ESO to take more efficient actions, ranging from identifying future system needs through to constraint management actions in its control centre.

Table 19 also shows the % benefits assumed for each use case. These are derived from greater visibility of all DG. To understand the relative proportion of non-visible DG the ESO has used FES 2021 data on future transmission and distribution connected generation capacities. It has also accounted for visible DG such as parties with Bilateral Embedded Generation Agreements (BEGAs).

The remaining use cases could confer additional benefits in each scenario as the volume of visible DG changes. The ESO has therefore assessed all four scenarios for each use case.

Table 199: ESO benefit quantification related to thermal congestion cost

High level use case	CBA methodology
3. Ancillary and balancing service provision	Constraint costs = constraint volumes x unit cost. Greater volume of providers could reduce average unit cost by 0.25%
8. Real time operations	Constraint costs = constraint volumes x unit cost of constraint 5% improved forecast data proportioned by proportion of visible DG realised
9. Outage planning	Constraint costs = constraint volumes x unit cost of constraint 3% improved limits; more accurate data by proportion of visible DG realised
10. Long term development	Constraint costs = constraint volumes x unit cost of constraint 2% better demand data by proportion of visible DG realised

5 https://www.nationalgrideso.com/document/194436/download

B. Benefits arising from improved system resilience

In quantifying the benefit, ESO has assumed that this would reduce the probability of a major system event from a one in 10-year event to a one in 20-year event. The ESO has assumed that greater operational visibility of all DG would remove the need for one tranche of demand control (5% of national demand). This has then been proportioned by the volume of non-visible DG realised through the Open Networks work in this area. The ESO has used a Value of Lost Load of £6000 /MW/h as quoted in the Balancing and Settlements Code.

The ESO has considered the potential electrical demand at the time of an event to create a benefit range. It has assumed that the impact would be for a one-hour period, but this could be pro-rated for further assessment.

Table 20: ESO benefit quantification related to System Resilience.

High level use case	CBA methodology
7. System resilience	Value = VoLL * %demand loss reduction * demand * duration of loss

C. Benefits arising from improved system restoration

The ESO has provided the benefits developed as part of the Distributed Restart bid document (£115M NPV by 2050). It has proportioned these benefits consistent with the approach listed in section 7.1.1. In this use case the ESO has only considered retrofit scenario 4 (DG capacity >1MW) assuming market entry for parties below 1MW would not be feasible at this time. It has also assumed that the minimum benefit would be zero recognising none of these generators may be appropriate or prepared to provide this service.

7.1.2. Benefit results

The ESO benefits results for the uses cases described above are summarized in Table 21.

Table 21: ESO use cases benefits results

	SC1 (0kW)		SC2 (200 KW)		SC3 (500kW)		SC4 (1MW)	
	Min	Max	Min	Max	Min	Max	Min	Max
3. Ancillary and balancing service provision	0.53	4.81	0.53	4.81	0.53	4.81	0.53	4.81
4. System restoration (black start)	0.00	0.47	0.00	0.47	0.00	0.47	0.00	0.47
7. System resilience	0.09	0.14	0.09	0.14	0.09	0.14	0.09	0.14
8. Real time operations	0.47	5.11	0.50	5.38	0.52	5.63	0.53	5.77
9. Outage planning	0.28	3.07	0.30	3.23	0.31	3.38	0.32	3.46
10. Long term development	0.19	2.04	0.20	2.15	0.21	2.25	0.21	2.31
TOT	**1.57**	**15.64**	**1.63**	**16.18**	**1.67**	**16.68**	**1.69**	**16.96**

7.2. Customers benefits - DNOs driven

We believe greater DER visibility and monitoring especially on the HV network where gaps have been identified, are key enabler for DNOs in tackling both distribution and whole electricity system challenges and enable transition towards DSO. The DNO use cases for having this data cover both planning and operational time horizons and include Active Network Management (ANM) operation, Flexibility Services dispatch, enhancement of existing network and outage panning processes, fault level management as well as real time network operation.

The approach we have taken to quantify benefits, is to only include benefits that could be unlocked from DER visibility which:

- Does not require any additional investment to be unlocked (e.g. forecasting system, CIM model etc),
- Only require operational metering data (there are a number of use case that would require additional data points e. g market data/ physical notification data for the benefits to be fully unlocked.)
- Only refers to the visibility aspect of the DER rather than the controllability aspect.

Benefits that cannot be quantified at this stage because of the reasons above, are qualitatively descried below and have not been factored in the CBA. The benefits that have been quantified are captured in the next section, along with quantification methodology, assumptions and results.

7.2.1. BENEFIT QUANTIFICATION

Flexible Connections Dispatch (Use Case 1)

Beside visibility on ANM generators, which is a key requirement to be able to connect as a Flexible Connection, network-wide visibility of real time DER output will allow more informed real time decision making from Active Network Management allowing us to better utilise network capacity and help reduce curtailment figures.

Currently, Flexible Connection schemes are designed using offline network modelling tools considering absolute worst-case scenarios e.g. network faults happening at times of maximum generation/minimum demand scenarios. We are moving towards a more automated and online ANM system that is based on dynamically updated network models (via CIM). By running real time load flows, contingency analysis and state estimation, this secures the network closer to real time, adapting the level of curtailment based on actual network requirements. Real time DER and network data are required to run real time online network studies and ultimately decrease the level of curtailment Flexible Connections are subject to.

In addition to the above, DNOs also generally assume that all generators downstream of a constraint would simultaneously ramp-up with their maximum ramp rate when a constraint is breached, which affects the threshold at which ANM is designed to start curtailing (conservative ramp rate, lower thresholds, higher curtailment). By having visibility of all DG outputs in real-time, ANM can be designed to dynamically calculate thresholds based on the real time output of the generators downstream a constraint.

Flexibility Service Dispatch (Use Case 2)

We believe visibility of DGs participating into DSO Flexibility Services, will greatly benefit DNOs, primarily as it will bring higher confidence around DG response following a dispatch instruction, which will reduce over-dispatch in the expectation that not all capacity will be delivered reliably. (Further described in the benefit quantification section).

Moreover, having real-time DG visibility would give DNOs more information to allow better decisions to be made than just relying on substation data alone, for example:

- if we knew a specific DG has under delivered, we could contact them to escalate immediate remedial action;
- if we had to reconfigure the network and there are a number of DERs that have been dispatched but it's unclear which ones are actually delivering we couldn't be sure which part of network we could shift; and
- in future products, if similar to flexible connections, where DGs are instructed to run at a certain set point (rather than flexibility services at the moment that requests a change) we may need the current DG output as an input into the algorithm to decide what set-point we need to issue.

Another benefit of having DER visibility, where we don't currently have an RTU, is to determine whether the DER has already "self-dispatched". There is benefit for DNOs to have physical notification (PN) type data (out of WS1B P6 scope): having forward visibility of what the DG plans to could decrease the need to dispatch DERs. Without real time data from the generator, we would be unable to establish this fact and we would dispatch them anyway and the result is we would not see any change in network load but may still incur costs (depending on the commercial baselining methodology as to how we pay them).

Whole System Coordination (Use Case 6)

The need to coordinate operations across the distribution and transmission systems will continue to increase, with the maturity of Flexibility markets and more active networks at distribution. Availability of operational metering data DER data, will become essential for optimising the dispatch of services by running power system studies closer to real time.

We can see two main benefits from enhanced visibility of generators providing services both to ESO and DNOs.

A) Avoid service nullification

This happens when the MW service from DNO and ESO are in opposite directions (turn-up and turn-down). An example of that is the interaction between ANM and STOR generators connected downstream of an ANM constraint: when the ESO instructs a STOR generator to ramp-down because demand on the transmission is lower than forecasted, because of the freed-up capacity at the constraint ANM would instruct the ANM generator to ramp up, nullifying the request from the ESO. ESO will have to pay another STOR unit in another part of the network to achieve the desired MW turn down response. This could be avoided by having PN data, running load flows closer to real-time, and including DERs real time output at the time of the study

B) Avoid paying twice for the same service

This happens when the MW service from DNO and ESO are in the same direction (turn-up or turn-down). An example of that is the interaction between Flexibility Services (Dynamic) and TCM DER connected downstream a flexibility site: if a DNO instructs a DER to ramp-up to avoid demand constraint on a primary site, and subsequently the ESO instructs a TCM generator downstream the same Flex Site to ramp-down because of generation thermal constrain on the transmission network, the DNO would need to dispatch additional flexibility, if available, or it would be left with site outside firm capacity, which depending on the extent of the overload may require customers to be disconnected. Having real time visibility of DER output will allow DNOs and ESO to further optimise service requirements ultimately lowering costs. This could be avoided by having forward view visibility of ESO actions, running load flows closer to real-time and including DERs real time output at the time of the study.

Improved System resilience (Use Case 7)

Giving control rooms full visibility to the real time generation levels at both aggregated and specific sites, will enable them to respond promptly to events threatening system resilience.

Improved real time network operation (Use Case 8)

Greater operational DER visibility is also a key enabler for optimising real time network operation activities, including automatic restoration programmes and real time fault level management. This will facilitate more informed real time network decision making, improving network reliability and continuity of supply for our customers.

- **Real-time fault level management**

  Fault level issues may limit the connection of DGs if their fault level contribution exceed the switchgear rating: traditionally, this has been tacked by replacing switchgear with higher-rated equipment. As an alternative to that, real-time fault level management, allows to connect DG capacity cheaper and faster by executing switching actions to redistribute power flow and keep the fault level below the switchgear rating.

Beside fault level monitor and network impedance information, it requires operational metering data from the DER PoC.

- **Real-time automatic reconfiguration to maximise network capacity**

Due to the large uptake of electric vehicles and heat pumps forecasted at distribution level, the peak demand for electricity is expected to increase significantly. In order to accommodate this increased demand, DNOs would traditionally reinforce the existing network assets. Some DNOs are trialling a responsive, automated electricity network that re-configures itself in real-time, moving spare capacity to where the demand is, by changing open points on the network and optimising the behaviour of the Soft Open Points (SOPs) and Soft Power Bridges (SPBs). Wider access to telemetry data from demand and DG will enable more informed switching actions and optimised network performance. Findings from Active Response innovation project, showed that this type of automation programme could release approximately 4 MVA[6] of spare capacity per substation

Improvement of Outage Planning Processes (Use Case 9)

For planned and unplanned outages, having access to short term operational DER generation forecast, would allow DNOs to make more informed assessments on impacts and contingencies. This would enable transitioning away from using worst-case operational scenarios (maximum generation in coincidence with minimum demand) for modelling where this DER data is currently unknown to using forecast DER load and generation data. This could lead to less conservative assumptions and increased access to network capacity for customers during outage conditions.

Network Planning processes / SCR (Use Case 10)

Based on the change in the connection boundary under consideration as part of Ofgem's SCR, generators will be only responsible for the cost of network reinforcement (or will be considered Flexible) for the same voltage level of their connection, and will be considered firm for higher voltage levels. Flexibility markets are being considered as an alternative to manage generation constraints prior to reinforcement. DER Operational metering is a key enabler to allow closer to real time capacity/curtailment markets.

Demand Forecasting (Use Case 11)

Operational forecasting is a key enabler for DNOs to transition towards a distribution system operator (DSO) role.

Short term forecasting (e.g. T+5 minutes) will requires a system automatically getting operational metering and producing generation output forecast that different applications will make use of. The same could not achieved with settlement data from customer as there is a lead time of days to get them into DNO's system.

For certain technologies, such as battery storage, closer to real-time forecasting of network constraints is critical in ensuring maximum access to the system – thereby increasing the benefits of these technologies in supporting system needs.

Moving towards DSO activities, operational demand forecasting will enable activities such as network constraints and curtailment modelling in operational timescales. Closer to real-time load forecasting on flexibility sites, will allow the procurement and dispatch of flexibility based on a more accurate view of forecasted network needs. Operational Demand forecasts will also enable outage planning and real time network operation activities to secure the network more optimally.

Compliance with relevant standards (Use case 13)

We believe that visibility of POC operational metering from DER connected on HV feeders, will provide us with greater information on voltages along the feeder. The same could be achieved with greater LV visibility budgeted for in RIIO-ED2 plan by most DNOs.

[6] Project Deliverable 4 – Learning from commissioning and operation of Active Response software solution tools (ukpowernetworks.co.uk)

Voltages especially at the end of rural feeders could be outside of voltage statutory limits, without the DNO being aware (if no monitoring available), which would cause:

- a potential breach of grid code and standards;
- possible reputational and/or property damage; and
- if voltages are considerably outside (more than +/-10%) the range, it would not allow customer to synchronise to the network

Having visibility of voltage profiles through DER connected (especially at the end of the feeder) would allow DNOs to be proactive changing tap positions making sure that voltage profiles are within the range.

Facilitation of new markets (Use Case 14)

DNOs are considered to have a cardinal role in the facilitation of the new markets. New markets such as peer-to-peer trading could utilise capacity on the network through non-traditional methods and allow the value of that capacity to be determined through market-based mechanisms.

Operational metering will become essential for optimising system capacity and for the roll out services such as trading or curtailment. Customers will directly benefit both financially and in terms of access to capacity through an optimised system. Opportunities via flexibility markets will enable our customers to earn additional revenues and reduce the cost of lost revenues due to curtailment.

7.2.2. BENEFIT QUANTIFICATION

A. Flexibility Service Use Case

BENEFIT DESCRIPTION

Without DER visibility DNOs would over dispatch in the expectation that not all capacity will be delivered reliably. In some cases, all the dispatched capacity will be delivered which would exceed our requirement and we would incur unnecessary cost. If we had real time visibility of DER we could detect when the DER has failed to deliver and dispatch more as required. In this way we would adopt a strategy of dispatching what we need and only dispatch more if required, thereby saving on not having to over dispatch at the outset.

A similar result could be achieved in part with network visibility i.e., real-time data from the substation can highlight to us when there is under delivery and we can then dispatch more as required. Notably though this would not allow differentiation of the driver for changes in power flows.

BENEFIT QUANTIFICATION

We have quantified benefits from enhanced visibility of DER participating into Flexibility Services, as the volume that we would over dispatch due to lack of confidence around DER response, multiplied by the cost of the service and the hours a year DERs would be dispatched to provide the service.

If the DER dispatches as instructed, we would exceed our requirement and we would incur unnecessary cost. Hence the savings are determined multiplying the figure determined above, times the historical under delivery figures.

Because part of the DER capacity currently participating into Flex Services is already monitored (we want to assess benefits from higher visibility), we have multiplied the benefits times the unmonitored capacity factors, which was identified at Gap Analysis stage and varies depending on the scenario considered (SC1-SC4). Methodology for benefit quantification is summarized below.

Item	Benefit Quantification
£/year savings=	MW over dispatched * [£/MWh payment] * [hours/year dispatch]* [Historical under-delivery figures] *Unmonitored capacity%

BENEFIT ASSUMPTIONS

Summary of the assumptions made to quantify the Flexibility Service benefits unlocked from higher DER visibility, as well as the scenarios we studied, are summarized in Table 22.

Table 22: benefits assumption – Flexibility Service Use case quantification

Item	Assumption
Service Cost – volume weighted averages	~175 -400£/MWh
Over dispatch Factor	1.4
MW over-dispatched	= MW requirement (Over-dispatch factor – 1)
Historical Under-delivery	67%
Hour/year dispatched	50-200 hours/year

The MW of flexibility requirement has been taken from the ENA repository of Flexibility figures across Great Britain as of July 2021 that can be accessed here: Resource library – Energy Networks Association (ENA).

There are other reasons why DNOs would over dispatch flexibility beside not having visibility or DER operational metering, including DER reliability, confidence around the load forecast and liquidity of the market. We therefore have considered that 50% of the benefits could be attributed to greater DER visibility.

BENEFIT RESULTS

We believe greater DER visibility, will enable DNOs to avoid over-dispatching due to uncertainty around DER response, optimising the volume and DER to be dispatched dispatch based on actual network need. Summary of customer benefits for each retrofit scenarios are captured in Table 23 below.

Table 23: Summary of benefits from enhanced DER visibility/Flexibility Service Use case

CBA scenario	Minimum Capacity to retrofit	Benefit Min	Benefit Max
SC1	> 0kW	£281K (2023) – 533 K (2028)	£1.1 (2023) -2.13 M (2028)
SC2	> 200 kW	£281K – 533 K	£1.1-2.13 M
SC3	> 500 kW	£270K – 509 K	£1.08-2.03 M
SC4	> 1MW	£256 K – 486 K	£1.0-1.93 M

B. Improvement of Real Time Network Operations (use case 8)

Beside all real time network operation activities that will benefit from enhanced visibility, it would mostly be seen in the Active Power Restoration System (APRS) use case, which would allow APRS to take better operation control decision reconfiguring the HV network.

BENEFIT DESCRIPTION

APRS automatically executes a sequence of switching actions to isolate the fault and restore power to the rest of the network. APRS only uses the feeder pick up load, and generation could be masked (In the example in Figure 7, 1.5 MW load, 1 MW generation -> pickup load = 0.5 MW). Masked generation on the feeder could cause APRS mal operation, executing switching action which cause additional faults, affecting Customer interruptions.

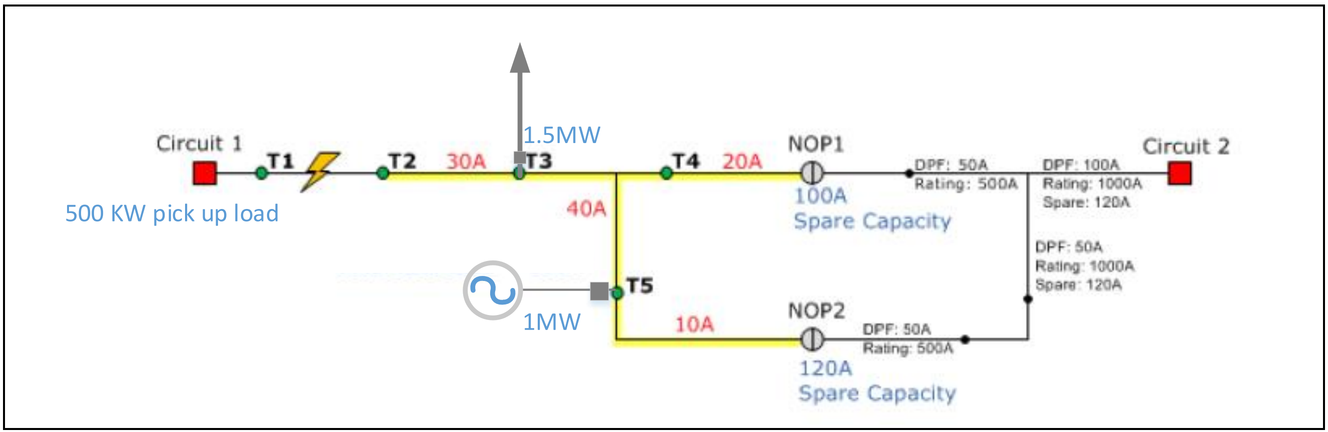


Figure 7: Example scenario triggering potential APRS mal-oration

Greater visibility of individual DER output integrated into APRS would allow APRS to take smarter operational decision and to save customer interruptions and customer minutes lost.

BENEFIT QUANTIFICATION

We quantified the benefits in terms of £/year saved to customer based on the time they would be off supply due to APRS mal-operation to which we have attributed a Value of Lost load (Voll).

First, we have looked at the number of feeders across DNOs areas that would be at risk of APRS mal-operation, which are considered to be the feeders with installed capacity larger than 50% of the circuit rating. This is based on the assumption that transferring a feeder load with installed capacity larger than 50% to another feeder with installed capacity larger than 50%, could exceed circuit rating and trip feed for overcurrent protection, which cause customers being off supply.

We then looked at the likelihood of these feeders with installed DG capacity larger than 50% to be affected by faults (faults/feeder/year), that is when APRS would operate.

We have then assessed the potential MWh interruption on the feeders at risk of potential mal-operation, which customers could be subject to. We considered an average number of customers per feeder affected by faults times their average consumption, and the duration during which they would be off supply due to APRS mal-operation. This gives total customer MWh lost.

Multiplying the MWh lost times the value of loss load, we have calculated the £/year saved to customers.

Saving	Methodology
£/year saved	[# of feeders at risk of APRS mal-operation] * [faults/feeder/year] *[number of customers affected * average power]* [average interruption duration] *Voll (6000 £/MWh)

BENEFIT USE CASE ASSUMPTIONS

Summary of the assumptions made to quantify benefits of having APRS taking better operational decisions, as well as the scenarios we studied, are summarized in Table 24.

Table 24: Use case assumption: APRS use case benefit quantification

Item	Assumption
Faults/feeder/year	0.05
Feeders at risk of APRS mal-operation	580-1300 (scenarios)
Average Customers affected	300/200KW
Average interruption duration (not within 3 minutes)	5 min-30 min (scenarios)
Over dispatch Factor	1.4
VOLL	6000 £/MWh

Some DNOs don't currently make use of APRS or have an APRS system that operates based on fixed thresholds rather than operational network data (feeder pick up load). Some another DNOs would not allow to re-energize DERs in abnormal arrangements. To have a consistent approach, we have quantified potential benefits that all DNO could see with a smarter APRS system in place which is where the industry is moving towards, so some of the benefits are not going to be seen from day one.

BENEFIT RESULTS

We believe greater DER visibility, will enable APRS to take better operational decision and to save customer interruptions and minutes lost. Summary of customer benefits based on retrofit scenarios are captured in Table 25 below.

Table 25: Summary of benefits from enhanced visibility/APRS Use case

CBA scenario	Minimum Capacity to retrofit	Benefit MIN	Benefit Max
SC1	> 0kW	£0.68M	£9.0 M
SC2	> 200 kW	£0.675M	£8.96 M
SC3	> 500 kW	£0.67M	£8.85.M
SC4	> 1MW	£0.66M	£8.75 M

8. CBA Results

This section provides the Cost Benefit Analysis (CBA) results which looked at costs and benefits to enhance DER visibility on distribution network across GB, retrospectively retrofitting sites where DNOs don't have operational metering.

Main inputs to the CBA are the total number of unmonitored sites currently installed on HV and EHV networks across GB (output of Section 4), the DER retrofit CAPEX and OPEX cost (output of Section 5) and the benefits that ESO, DNOs and customers will see from enhanced DER visibility (output of Section 6).

8.1. CBA assumptions summary

Cost and benefits assumptions that have been taken along the way as well as the approach we took to carry out the CBA, are summarized below:

- Cost and benefits are assessed for the increase visibility of DER operational metering (P, Q, V, I, CB status) which covers level1 and Leve2 of the Gap Analysis. We have not looked at the accuracy of the operational metering of existing fully monitored sites (level 3 CBA – enhancing accuracy).
- Benefits are calculated only for the DER visibility part, no benefits related to the ability to control DER have been quantified.
- Benefits considering operational metering specification in line with EREC G99 (no benefit have been quantified for ESO energy services which require second by second resolution.)
- DNOs and ESO benefits have been assessment based on the portion of capacity that DNOs don't currently have visibility over, corresponding to 7.4 GW.
- As described in the benefit section, the benefit that have been quantified only include those that do not require any additional investment or data points other than operational metering, for the benefits to be unlocked.
- It has been assumed that all the DER retrofit work is completed at the end of year 0 and that the full benefit could be unlocked from year 1 (2023). The cost of retrofitting DER has bene fully allocated in year 0 (2022) and has not been split in several years.
- We have carried out a relatively simple CBA, not looking at interest, depreciations cost etc.

8.2. Summary of Cost and Benefits

Summary of total CAPEX cost and total OPEX for SC1-SC4 retrofit scenario are shown in Table 26 and Table 27 respectively.

Summary of benefits that greater visibility will unlock to ESO and DNOs are captured in Table 28 and Table 29 respectively.

Table 26: Total CAPEX

	CBA scenario	Minimum Capacity to retrofit	Retrofit Cost BEST case	Retrofit Cost WORST CASE
TOTAL CAPEX	SC1	> 0kW	£69.8 M	£131.5 M
	SC2	> 200 kW	£46.3M	£87.4 M
	SC3	> 500 kW	£33.1M	£66.9 M
	SC4	> 1MW	£25.3M	£41.6 M

Table 27: Total OPEX

	CBA scenario	Minimum Capacity to retrofit	Number of new sites on SCADA	BEST CASE	WORST CASE
TOTAL OPEX	SC1	> 0kW	5265	£1.01M/year	£1.23M /year
	SC2	> 200 kW	3373	£0.67M/year	£0.81M/year
	SC3	> 500 kW	2316	£0.48M/year	£0.58M/year
	SC4	> 1MW	1686	£0.37M/year	£0.44M/year

Table 28: Total ESO Benefits

	CBA scenario	Capacity to retrofit	Min benefits	Max benefits
TOTAL ESO BENEFITS	SC1	0kW	£1.69 M /year	£17.0M /year
	SC2	200 kW	£1.67 M /year	£16.7M /year
	SC3	500 kW	£1.63 M /year	£16.2M /year
	SC4	MW	£1.57 M /year	£15.6M /year

Table 29: Total DNO Benefits

	CBA scenario	Capacity to retrofit	Min benefits	Max benefits
TOTAL DNOs BENEFITS	SC1	0kW	£0.97(2022) – 1.23M(2028)	£10.2 (2022)-11.2 (2028) M / Year
	SC2	200 kW	£0.96-1.21 M-	£10.1 – 11.1 M / Year
	SC3	500 kW	£0.94- 1.18 M	£9.9 – 10.9 M / Year
	SC4	1MW kW	£0.93- 1.14 M	£9.8 -10.7 M / Year

8.3. DER visibility CBA Approach and Results

Lower capacity to retrofit e.g. 0kW, SC1, implies a higher number of sites to retrofit, corresponding to higher capital and operational expenditures; a higher capacity to retrofit (e.g.1MW, SC4) instead, implies a lower number of sites to retrofit, corresponding to lower capital and operational expenditures.

Benefits have been assessed based on the volume of 'visible capacity' associated to each of the retrofit scenario: SC1 would unlock more benefits than SC4 due to the higher capacity that is made visible to DNOs and ESO.

For each of the retrofit scenario, we have carried out a CBA, ultimately looking at the payback period of the capital expenditure required to enhanced DER visibility, which looks at the time it takes to recover the cost of the initial investment based on the calculated yearly customer benefits, driven by DNOs and ESO benefits. The level of benefit that the additional 'visible' capacity unlocks, may not be offset by the cost of enabling DER visibility, which is what the CBA intends to advise on.

For each of the retrofit scenario (SC1 –SC4) we have analysed combination of best case (optimistic) and worst case (pessimistic) cost and benefits. Summary of results are summarized in Table 30 below.

Table 30: CBA results – Investment payback time

Scenario	Capacity to retrofit	Cost Scenario	Min Benefits	Average Benefits	Max benefits
SC1	>0 kW	Min Cost	>20	5	3
		Max Cost	>20	10	5
SC2	>200 kW	Min Cost	>20	4	2
		Max Cost	>20	7	4
SC3	>500 kW	Min Cost	~20	3	2
		Max Cost	>20	5	3
SC4	>1 MW	Min Cost	12	2	2
		Max Cost	13	4	2

The payback time of the investment required to retrofit all (SR1) unmonitored sites across GB distribution network varies considerably based on the combination of cost/scenario considered. Taking the relatively conservative scenario Maximum Cost (CAPEX and OPEX) and Average benefits, the investment would be paid back in 9 years. This goes does to 6 years for SC2 (200 kW), 5 years in SR3 (500 kW) and 3 years in SR4 (1MW).

As part of the operation metering Gap Analysis, it was identified that the total 7.4 GW on unmonitored capacity across DNOs network is mostly made up of generators in the 1-10MW capacity bracket corresponding to 5.9 GW of capacity (79% of the total unmonitored capacity). The following consideration can be done:

Retrofitting all the invisible 1365 sites above 1MW (SR4) would provide an additional 6.6 GW DER visibility, whereas retrofitting all the invisible 3579 sites below 1MW, would provide an additional visibility of 0.86 GW as shown in Table 31 below. This can be broken down as follow:

- Retrofitting all the invisible **1894 sites** in the 0-200KW bracket (SR1) would only give an additional **190MW** of DER visibility (3% of the total unmonitored capacity
- Similarly, retrofitting all the invisible **1055 sites** in the 200-500 capacity bracket (SR2) would only give an additional **330 MW** of DER visibility (4% of the total unmonitored capacity)
- Finally, retrofitting all the invisible **630 sites** in the 500kW-1MW capacity bracket, would only give an additional **340 MW of DER** visibility (5% of the total unmonitored capacity).

Table 31: Gap analysis summary grouped by above and below 1MW.

Unmonitored sites	Sites/capacity not monitored	< 1MW	>1MW
Number of Sites	4944	3579	1365
Total Capacity	7.4 GW	0.86 GW	6.6 GW
% of capacity		11%	89%

Table 32 below compares the benefit from SC4, with the additional benefits that SC1-SC3 would unlock.

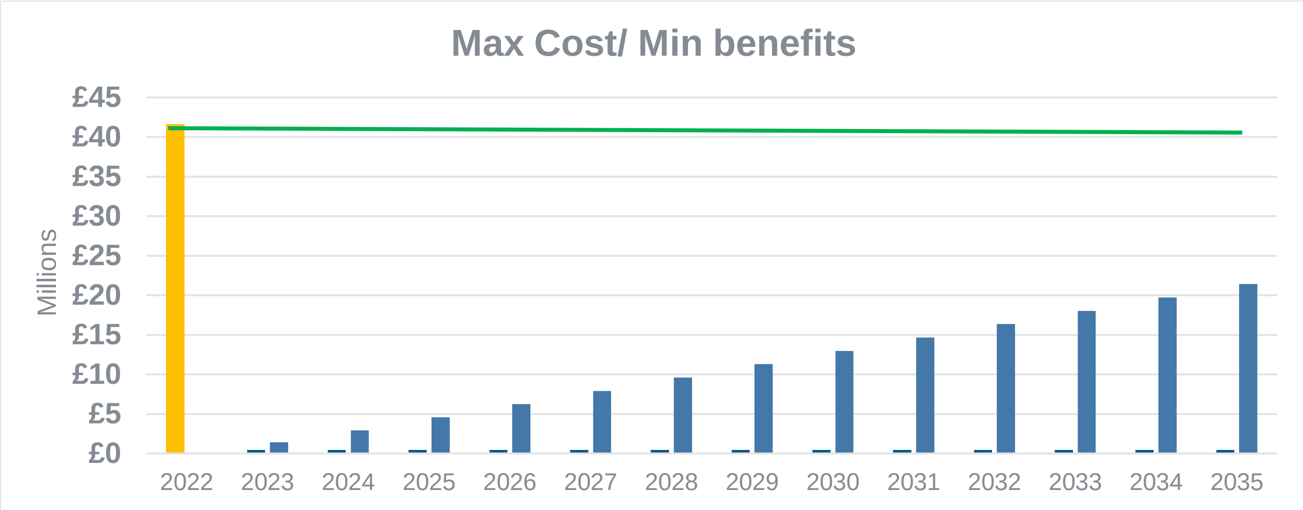
Cost Benefit Analysis results showed that the benefits from the additional DG visibility with capacity below 1MW, which accounts for a total 0.66 GW of capacity, are not considerable compared to the benefits that would be unlocked from the visibility of DG with capacity 1MW and above, which accounts for total 6.6GW. This assessment may change in the future with further maturing of flexibility markets and DSO.

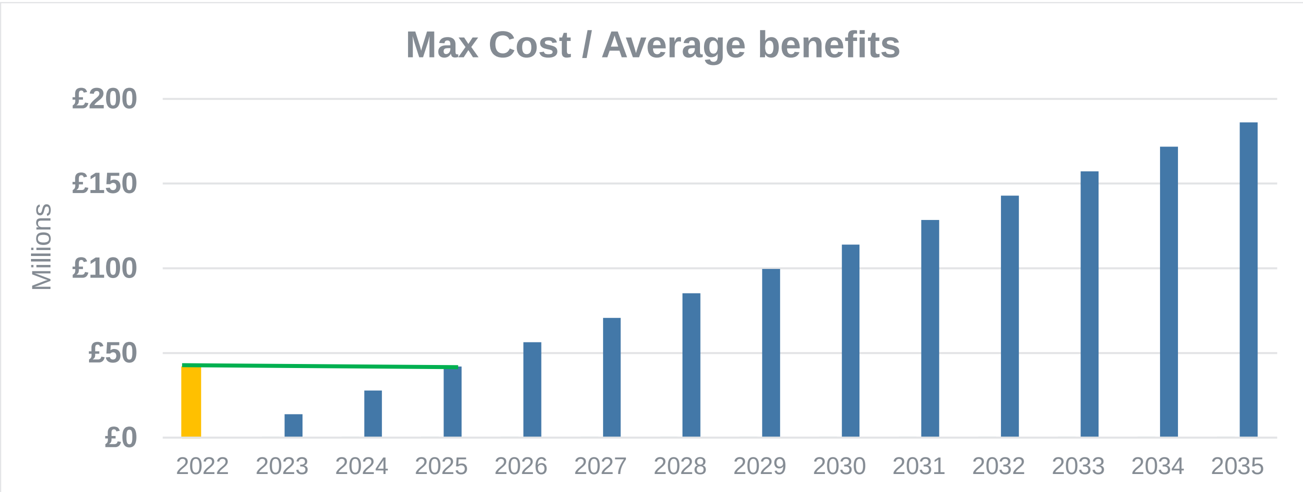
Table 32: SC1-SC3 benefit relative to SC4

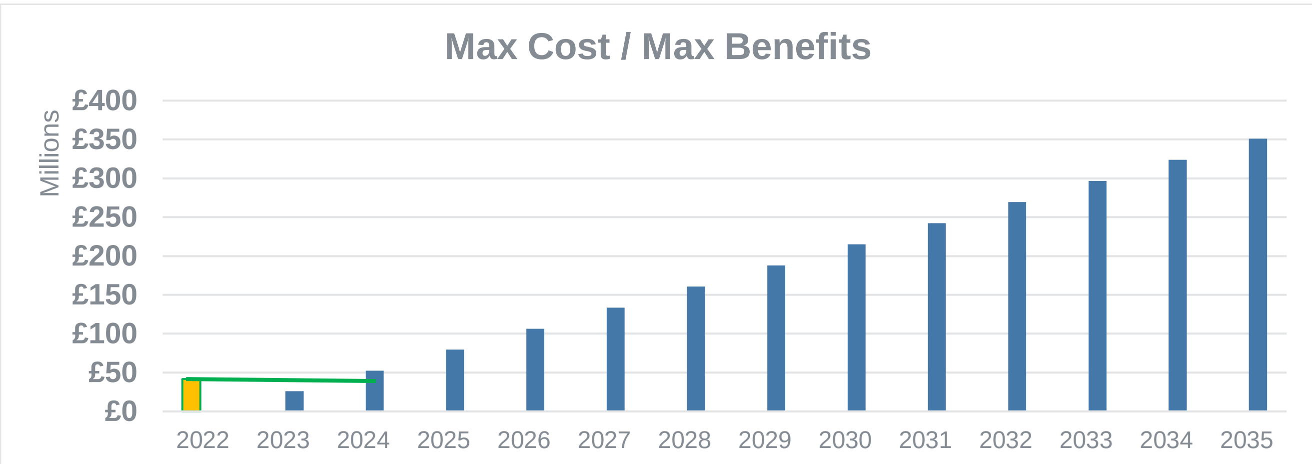
CBA scenario	Min	
SC4 Benefits (ESO + DNOs)	£2.48/year	£25.4/year
Additional Benefits of SC1 (0kW) compared to SC4 (1MW)	£0.2 M/year	£1.7 M/year
Additional Benefits of SC2 (200kW) compared to SC4 (1MW)	£0.1 M/year	£1.4 M/year
Additional Benefits of SC3 (500kW) compared to SC4 (1MW)	£0.08 M/year	£0.7 M/year

A.1. Appendix – CBA results

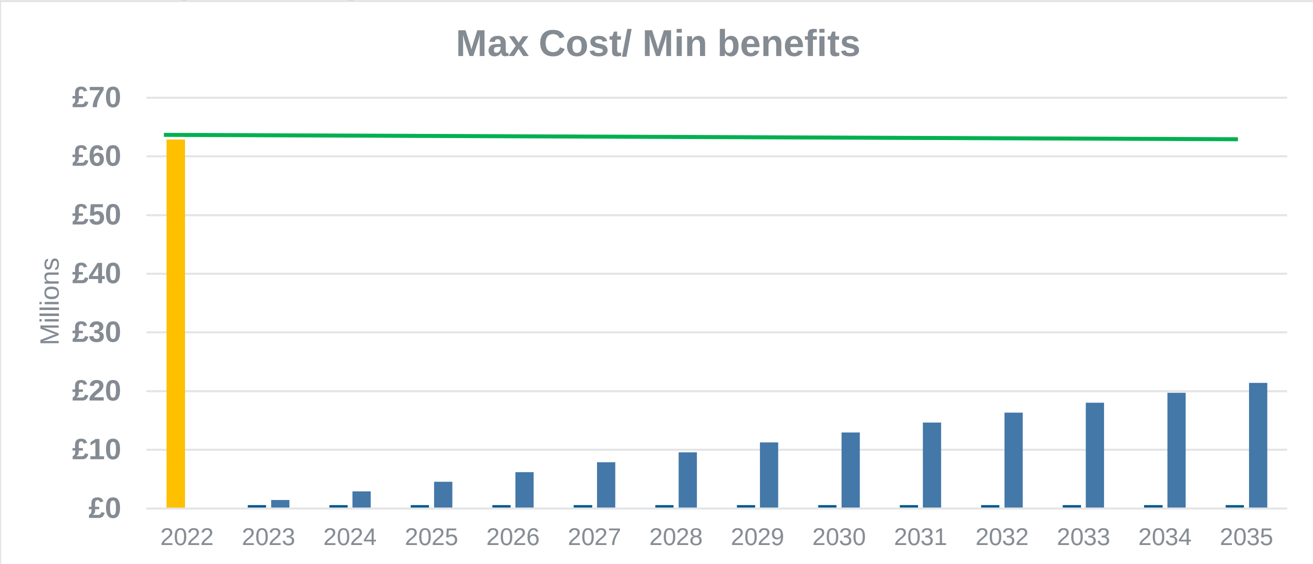
CBA SC4 (> 1MW)

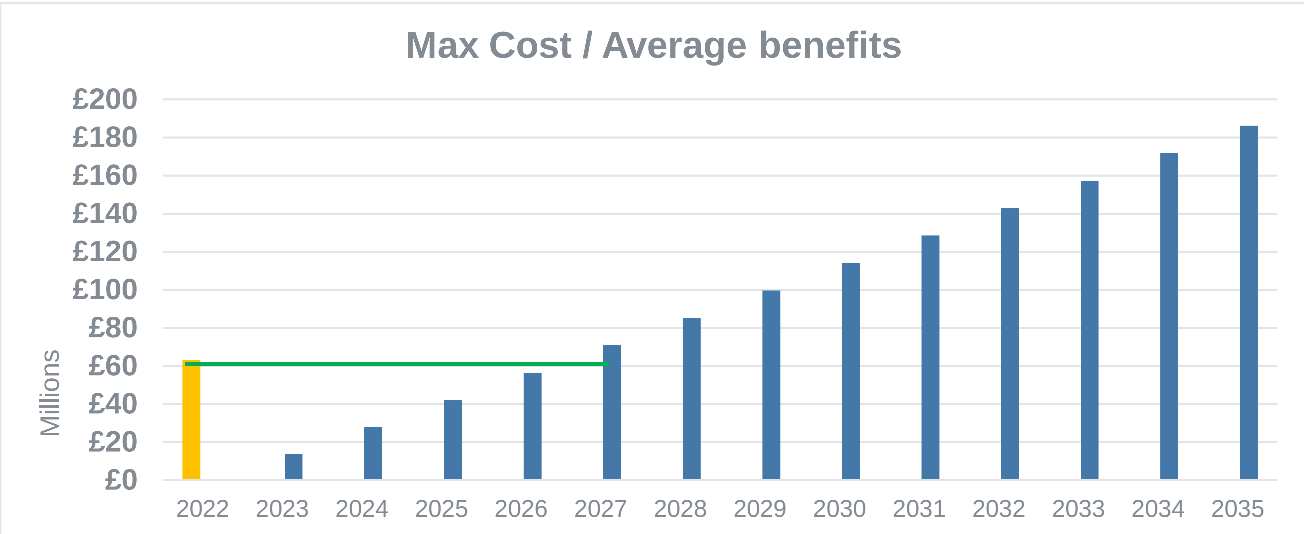


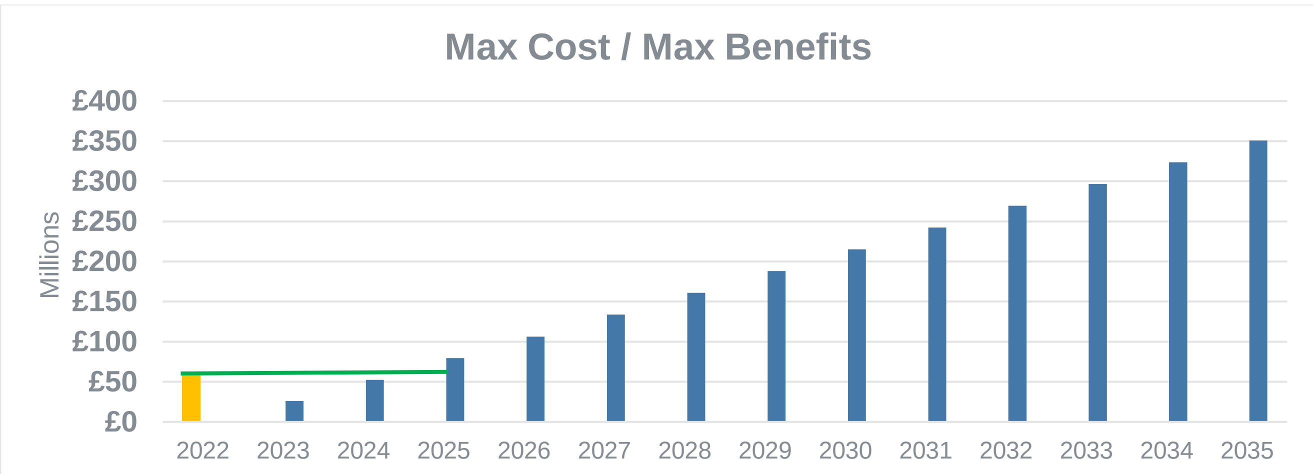




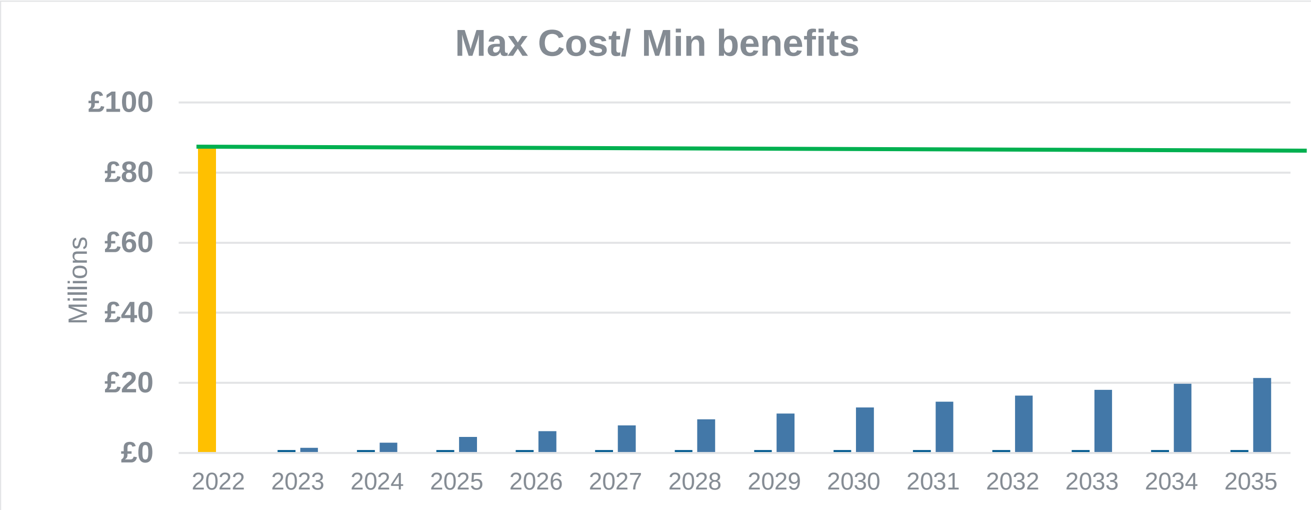
CBA SC3 (> 500 kW)

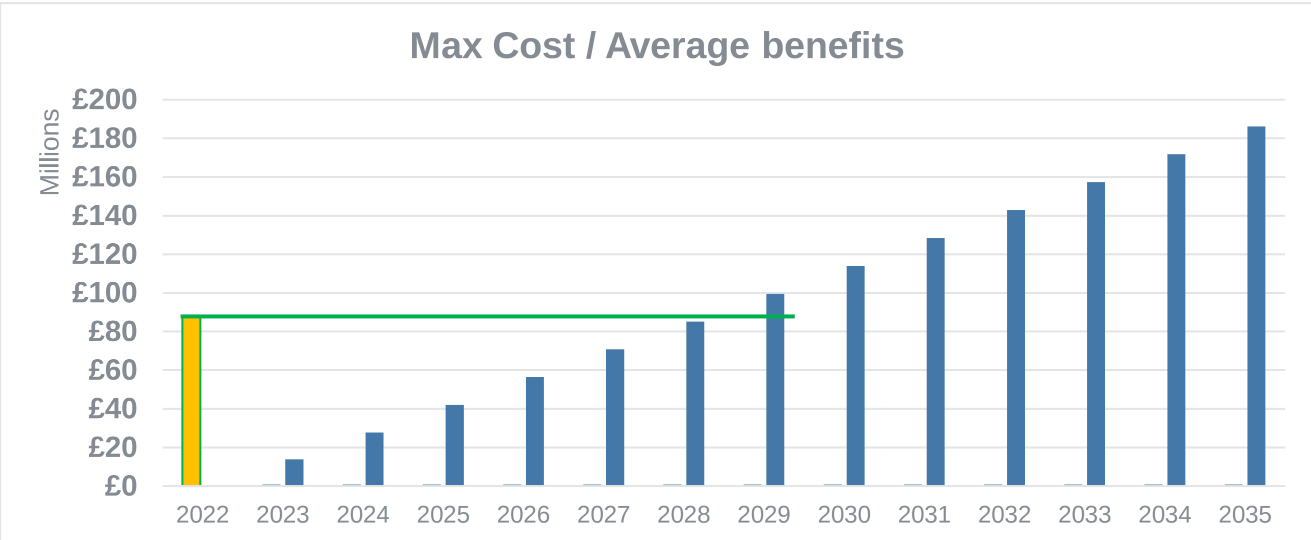


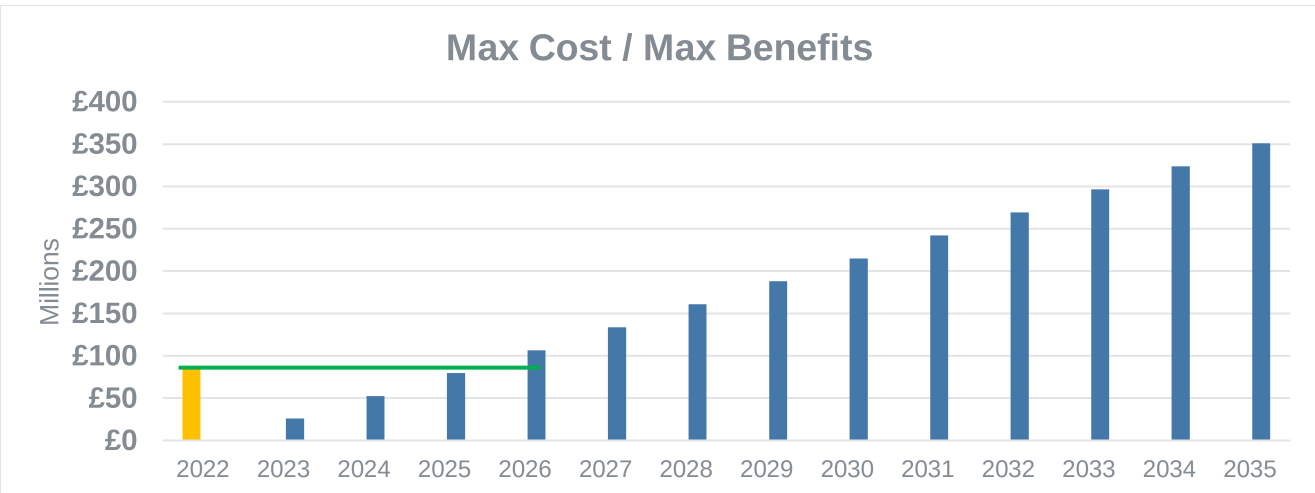




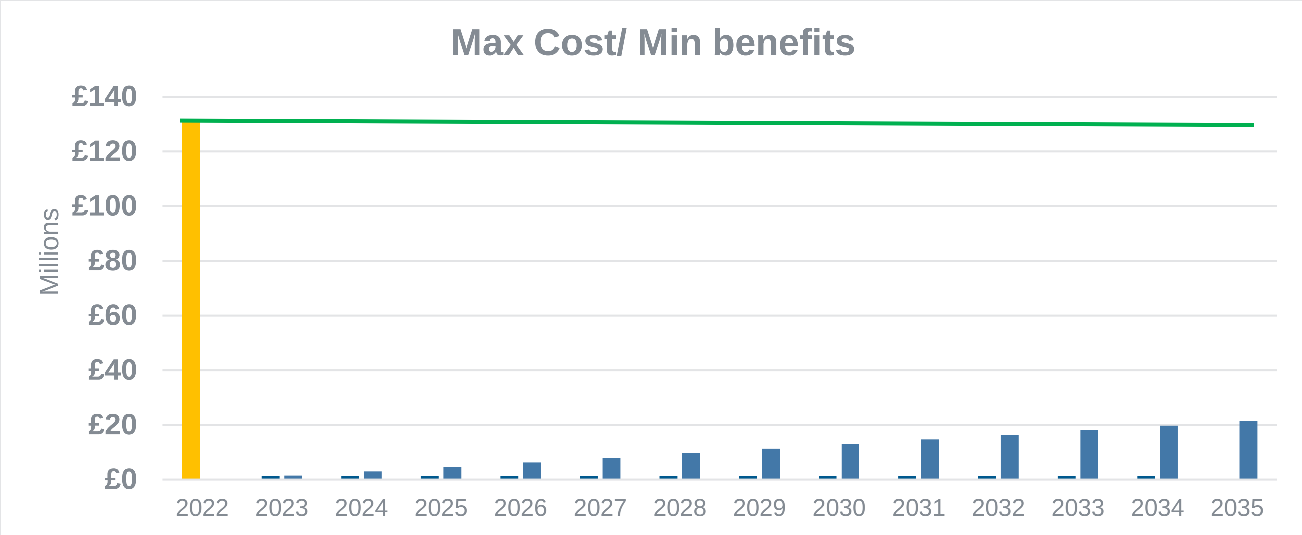
CBA SC2(> 200 kW)

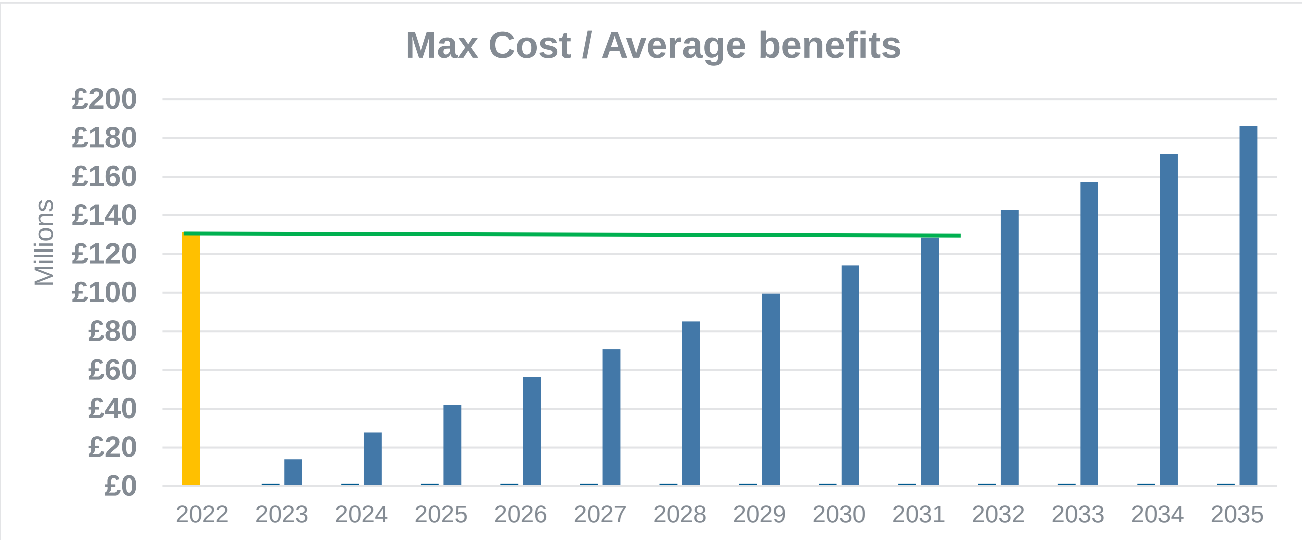


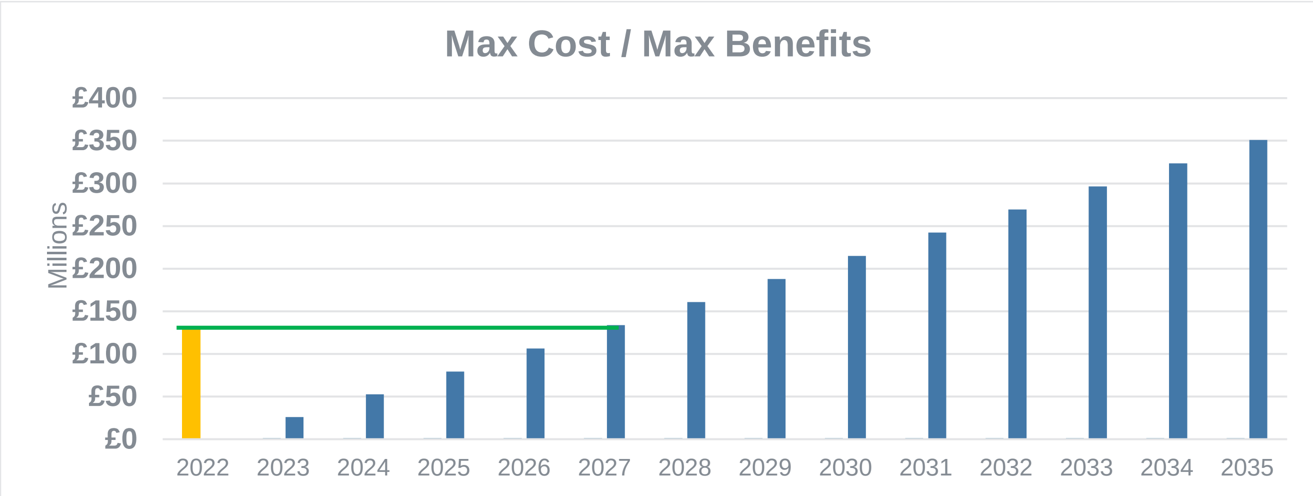




CBA SC1(> 0 kW)


Max Cost/ Min benefits
Millions
£140
£120
£100
£80
£60
£40
£20
£0
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035


Max Cost / Average benefits
Millions
£200
£180
£160
£140
£120
£100
£80
£60
£40
£20
£0
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035


Max Cost / Max Benefits
Millions
£400
£350
£300
£250
£200
£150
£100
£50
£0
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035

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