Public

Draft Final Modification Report

GC0139:

Enhanced Planning-Data Exchange to Facilitate Whole System Planning

Overview: To increase the scope and detail of planning-data exchange between Network Operators and National Energy System Operator (NESO) to help facilitate the transition to a smart, flexible energy system.

Modification process & timetable

1. **Proposal Form** 12 February 2020
2. **Workgroup Consultation** 17 December 2024 to 21 January 2025
3. **Workgroup Report** 03 December 2025
4. **Code Administrator Consultation** 06 January 2026 to 06 February 2026
5. **Draft Modification Report** 18 February 2026
6. **Final Modification Report** 10 March 2026
7. **Implementation** 10 Business Days after Authority Decision

Have 5 minutes? Read our Executive summary
Have 90 minutes? Read the full Draft Final Modification Report
Have 120 minutes? Read the full Draft Final Modification Report and Annexes.

Status summary: The Draft Final Modification Report has been prepared for the recommendation vote at Panel.

Panel recommendation: The Panel will meet on 26 February 2026 to carry out their recommendation vote.

This modification is expected to have a:
High impact: National Energy System Operator (NESO), Transmission Owners (TOs) and Network Operators (i.e. Distribution Network Operators and Independent Distribution Network Operators). **Medium impact:** Power System Analysis Software Vendors. **Low impact:** Non-embedded and embedded customers. **No impact**: Generators

Modification drivers: System Planning, System Security and Transparency

Governance route	Standard Governance modification assessed by a Workgroup	
Who can I talk to about the change?	**Proposer:** Steve Robertson Steven.Robertson@enwl.co.uk	**Code Administrator Chair**: Jess Rivalland Jessica.Rivalland@neso.energy

Contents

Executive Summary

This modification seeks to increase the scope and detail of planning-data exchange between Network Operators and the National Energy System Operator (NESO) to help facilitate the transition to a smart, flexible energy system.

What is the issue?

The existing requirements of the Grid Code (GC), in respect of data exchange between Network Operators and NESO, are insufficient for the coordinated and efficient planning of their networks. As the industry transitions to a smart energy system, these requirements must change to give Network Operators and NESO better visibility of each other's electricity system and its operation.

To facilitate the efficient and coordinated planning of the Transmission System, NESO and Transmission Owners (TOs) need a greater understanding of system power flows and fault contributions and, the quantity, type, and impact of distributed energy resources connected to distribution networks.

To facilitate the efficient and coordinated planning of their distribution networks, Network Operators need a greater understanding of Transmission System power flows and fault contributions in a variety of Demand and generation scenarios.

What is the solution and when will it come into effect

Proposer's solution: Enhanced level of planning data exchanged between Network Operators and NESO; the data exchanged will largely be in a Common Information Model (CIM) format, supplemented by data from Network Operators in an Excel Workbook format. Data exchanges will take place twice a year between NESO and Network Operators. Details of the new routine data submissions can be found in the new sections of the Planning Code (PC), PC.9, PC.10 and PC Appendix G.

Implementation date: 10 Business Days after the Authority decision, with the new obligations taking effect from 01 January 2027.

What is the impact if this change is made?

This modification will require all Network Operators to have the capability to produce power system models in a CIM format, based on the Common Grid Model Exchange Standard (CGMES) v3 standard with required extensions and deviations to meet the data exchange requirements of the PC. It will require NESO to extend its current CIM capability to produce a power system model of the National Electricity Transmission System (NETS) or produce a bespoke NETS equivalent model for each Network Operator in CIM format.

Whilst this represents a significant increase in workload for NESO and the Network Operators, the proposal represents the most efficient way to exchange the enhanced data required as the industry transitions to a smart energy system and assist NESO, TOs and Distribution System Operators in complying with their requisite licence obligations.

- This modification will require the establishment of a CIM interface point agreement system. This modification will also require the establishment of a CIM governance body for Great Britain.
- A secure data exchange platform will be required to facilitate the exchange of data between NESO and the Network Operators.

Workgroup conclusions: The Workgroup concluded unanimously that the Original Proposal better facilitated the Applicable Grid Code Objectives than the baseline.

Code Administrator Consultation: The Code Administrator Consultation received 7 non-confidential responses and 0 confidential responses.

Panel recommendation: Panel will meet on 26 February 2026 to carry out their recommendation vote.

Interactions

Key interactions are listed below. However, further consideration was given to other codes and modifications, and details of these are outlined in the main Interactions section.

- GC0117 - may change the definition of a Large Power Station and under the present Grid Code would have implications for Network Operators week 24 submission. The proposed modification has been developed so that it is agnostic to the outcome of GC0117.
- GSR029 – alignment of definitions and the use of data provided in the Network Operators week 24 submission to assess Security and Quality of Supply Standard (SQSS) compliance.

What is the issue?

What is the defect the Proposer believes this modification will address?

The existing requirements of the Grid Code, in respect of data exchange between Network Operators and NESO, are insufficient for the coordinated and efficient planning of their networks going forward. As the industry transitions to a smart energy system, these requirements must change to give Network Operators and NESO better visibility of each other's system and its operation.

Network Operators are experiencing an increasing volume of Distributed Energy Resource (DER) connection applications. These connections include generation connections of differing energy conversion technology and fuel type, electricity storage facilities and Demand connections where their operators offer a Demand side response service. These DER connections present a new set of issues in relation to the planning and operation of the distribution network and Transmission System.

Similarly, the move away from coal and oil-fired generation towards large scale renewable and High Voltage Direct Current (HVDC) interconnector technology, is changing the operation of the NETS and its power flows. This presents a new set of issues to the planning and operation of Transmission System and distribution networks, particularly those in the case of distribution networks, which interconnect different Grid Supply Points (GSPs).

Why change?

To facilitate the efficient and coordinated planning of the Transmission System, NESO and TOs need a greater understanding of network power flows and fault contributions, and the quantity, type, and impact of DER connected to distribution networks.

To facilitate the efficient and coordinated planning of their distribution networks, Network Operators need a greater understanding of Transmission System flows and fault contributions within a variety of Demand and generation scenarios.

It is essential that network companies have a detailed knowledge of adjacent connected networks. This modification will significantly improve the scope and detail of the planning data exchanged between Network Operators and NESO.

What is the solution?

Proposer's Original solution

This modification proposes:

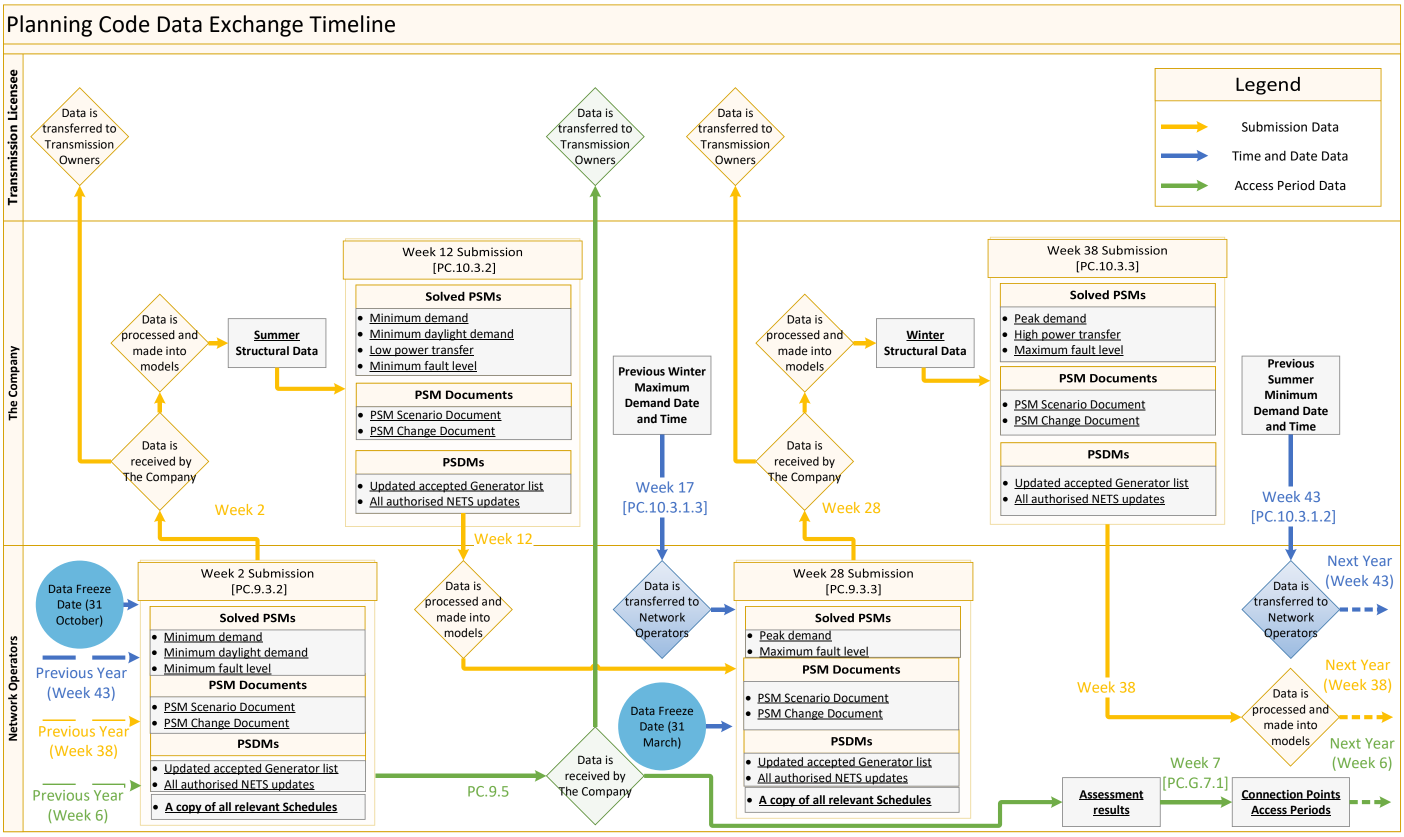
- To introduce a new section to the Grid Code Planning Code (PC.9) that describes the information to be provided by a Network Operator to NESO. The new PC.9 replaces the existing related PC obligations in respect of annual planning data submissions to NESO.
- To introduce a new section to the Grid Code PC.10 that describes the information to be provided by NESO to a Network Operator. The new PC.10 replaces the existing related PC obligations in respect of annual planning data submissions to Network Operators.
- To introduce a new appendix to PC.G that specifies the detail of the power system models in CIM format and associated documentation.
- To introduce new schedules in the Data Registration Code (DRC), describing the information provided by a Network Operator to NESO, that will support CIM models with forecasts of Demand and generation at cardinal points in time. These new schedules will apply to Network Operators and replace the existing schedules.
- To introduce new defined terms to the Glossary and Definitions.
- That there will be two submissions a year between Network Operators and NESO. These submissions will reflect the peak and minimum Demands on the Transmission System and connection points.
- That each submission will consist of a Power System Model (PSM) in CIM format, schedules, a PSM Scenario document and a PSM Changes Document.
- The requirements and timings of each submission are set out in Table 1 and Figure 1 below.
- To support the Evaluation of Transmission Impact (ETI) assessment process with the provision of updates of accepted-to-connect connections and their associated changes to the PSM. The routinely submitted power system models will be suitable for use in the ETI analysis, avoiding the need for bespoke modelling data to support an ETI assessment.

- Network Operators, in weeks 2 and 28, provide NESO with a switch level PSM in CIM format detailing the sub-Transmission network and equivalents representing networks at the boundary between the sub-Transmission network and networks operating at a lower voltage.
- That the lower voltage distribution network equivalents shall detail total Demand at the boundary and the generation at the boundary. The generation at the boundary shall be aggregated by energy source with existing generation detailed separately from generation that is accepted to connect but not yet connected.
- A PSM in CIM format of the distribution network shall be provided for the following Demand/generation scenarios:
    - NETS minimum Demands; and
    - NETS peak Demands
- NESO, at weeks 12 and 38, to provide Network Operators with PSMs in CIM format of a switch level, single boundary representation of the Transmission System.
- The physical extent of the representation of the Transmission System shall be bounded by boundary nodes agreed between NESO and Network Operators.
- That the PSMs of the Transmission System shall be provided for a number of Demand and generation scenarios, as follows:
    - Maximum fault level;
    - Peak Demand;
    - Summer minimum Demand;
    - Solar-peak/daytime-minimum Demand;
    - National high-power transfer dispatch scenario, and;
    - National low power transfer dispatch scenario.
- To align the data exchange requirements of the Weeks 2 and 28 data submissions with the those of an ETI such that the routinely submitted data will be suitable for use in the ETI analysis, avoiding the need for bespoke data to support an ETI assessment.

Table 1: High Level overview of GC0139 Submissions

		Routine	As Needed
Network operators to NESO (PC.9)	PSM	Week 2: Solved Subtransmission PS for NETS minimum Demands Week 28: Solved Subtransmission PSM for NETS peak Demands	Evaluation of Transmission Impact assessment: Planned connections and updated network development projects
Network operators to NESO (PC.9)	Tabular	Week 2: Schedules: 21A-C, 22, 29A-B & 30 Week 28: Schedules: 23A-C, 24, 25A-C, 26A-B, 27, 28, 29A-B, and 30	
Network operators to NESO (PC.9)	Narrative	Week 2: PSM Scenario Document/PSM Change Document Week 28: PSM Scenario Document/PSM Change Document	
NESO to Network Operators (Pc.10)	PSM	Week 12: Summer Solved NETS PSMs for 4 forecast grid conditions Week 38: Winter Solved NETS PSMs for 3 forecast grid conditions	Transmission Licensee-initiated modification: Planned connections/works and updated network development projects
NESO to Network Operators (Pc.10)	Narrative	Week 12: PSM Scenario Document/PSM Change Document Week 38: PSM Scenario Document/PSM Change Document	

Figure 1: GC0139 Submissions Timeline



A larger version of the diagram can be found in **Annex 10.**

PSM documents

<u>Types of data in a PSM</u>

There are four types of data in a PSM, Structural, Diagram, Situational, and Solution. Structural Data contains system components and their characteristics such as information about a transformer, the energy source of a Power Station or network voltage limits. Diagram Data is a visual representation of Structural Data. Situation Data is information on the status of system plant and assets, such as the Demand of a group of customers or the stored energy of an electricity storage device. Solution Data is the results of relevant power system analysis, such as the calculated Active and Reactive Power flows. These types of data are combined into a Solved PSM and exchanged between.

Solved PSMs are based on different system scenarios, such as peak Transmission System Demand or low Transmission System power transfer. Multiple PSMs might sent as part of each data exchange so that the receiving party can understand how the sending party's electricity system functions under different conditions.

Network Operator's PSM

The PSMs that the Network Operators submit to NESO in weeks 2 and 28, will contain:

- A model encompassing the whole of the sub-Transmission System – typically 132kV in England and Wales and 33kV in Scotland;
- Detailed modelling of any direct connections, e.g. Power Stations to the Sub-Transmission System;
- Equivalent modelling of any lower voltage system interconnection between Sub-Transmission Systems;
- Equivalent modelling of Power Stations connected to lower voltage systems, aggregated by energy source;
- Equivalent modelling of Demand connected to lower voltage systems, including Engineering Recommendations (EREC) G74 fault level contributions; and
- P, Q values at each boundary node with the Transmission System and any interconnected Network Operators system.

NESO's PSM

NESO PSMs are similar to Network Operator's PSMs. NESO will submit PSMs to Network Operators in weeks 12 and 38, which will contain:

- A switch level Transmission model of either the entire NETS or the NETS in sufficient local detail relevant to a particular Network Operator with equivalence of the rest of the Transmission System at boundary nodes;
- Generation modelled as equivalents, as detailed control systems will not be provided; and
- HVDC modelled as equivalents at each end of the DC link.

PSM Associated Files

Solved PSMs are accompanied by a PSM Scenario Document, a PSM Change Document, and have one or more Power System Difference Model (PSDM). The purpose of a PSM Scenario Document is to provide contextual information to help the receiving party better understand the submitted PSM and the assumptions made in developing it. A PSM Change Document's purpose is to explain what has changed in the Solved PSMs relative to the previously submitted Solved PSMs. A PSDM is a model which explains changes to a

PSM's Structural Data such as those associated with altered connections or proposed alterations to the sending party's system.

Submissions

Table 2 illustrates how new the schedules, PSMs and PSM associated documents would be submitted, compared to the current planning code submissions.

Table 2: GC0139 Submissions compared to current planning code

	Baseline	GC0139			
Week 50/2 User submission	DRC Schedules Updates on 5A-B, 5D-F, and 13 Given in last year's week 24/28	Solved PSMs Minimum Demand Minimum daylight Demand	PSM Documents PSM Scenario document PSM Change Document	PSDM Updated accepted **Generator** List All authorised updates	DRC Schedules 21A-C, 22, 29A-B, and 30
Week 6/12 NESO submission	Start and finish date for each **Access Group** and **Transmission Interface Circuit Connection Points** in each **Access Group**	Solved PSMs Minimum Demand Minimum daylight Demand Low power transfer Minimum fault level	PSM Documents PSM Scenario document PSM Change Document	PSDM Updated accepted **Generator** List All Authorised **NETS** updates	
Week 24/28 User submission	**Standard Planning Data** **Detailed Planning Data** part 1	Solved PSMs Peak NETS Demand and Maximum fault level at that time	PSM Documents PSM Scenario document PSM Change Document	PSDM Updated accepted **Generator** List All Authorised **NETS** updates	DRC Schedules 23A-C, 24, 25A-C, 26A-B, 27, 28, 29A-B, and 30
Week 38/42 NESO submission	**Network Data** (**Detailed Planning Data** part 2)	Solved PSMs Peak Demand High power transfer Minimum fault level	PSM Documents PSM Scenario document PSM Change Document	PSDM Updated accepted **Generator** List All Authorised **NETS** updates	

Both NESO and the Network Operators can request additional data from each other outside of the requirements in PC.9 and PC.10, provided that the requests are reasonable.

An overview of the new schedules

A subgroup of the GC0139 Workgroup developed a set of DRC schedules associate with this modification that are either updated versions of the current schedules or newly created schedules. To allow for easier completion and submission of the new schedules, they have been created as a single excel file split into separate worksheets for each schedule. This excel file allows for colour coding and drop downs to be added, contributing to easier submission of data. Schedules are submitted in either week 2 or 28, or in both.

The purpose of many of the new schedules is to keep up with the changing nature of the electricity system. The amount of generation that is connected to distribution networks is increasing, moving away from the traditional approach where most of the generation was connected to the Transmission System. To ensure that NESO has a better understanding of distribution networks in the context of network planning, a greater level of detail is required within Network Operator's submissions. Schedules which previously required seven years of forecasting have been altered to ten years, to allow NESO to have a better understanding of upcoming changes to distribution networks.

One of the largest blind spots for NESO relates to embedded electricity storage. To combat this, many of the new schedules make specific mention of embedded electricity storage, particularly in relation to their import or export at the various cardinal points in time.

DRC Schedule 21A-C (week 2)

The subgroup used the current Schedule 11 to create new Schedules 21 and 23, with 21 focused on summer minimums and 23 focused on winter peaks. Schedule 21 is split into three sheets based on three different network conditions: NETS minimum Demand, Connection Point minimum Demand, and summer daylight minimum. The latter was added due to the increase volumes of solar on the GB system.

Other changes in these schedules include the removal of references to the Single Line Diagram, as this is being replaced with the new CIM models, and the addition of rows where export from various Aggregated Energy Sources connected at and below the Sub Transmission voltage are to be added. Forecasting has been increased from seven years to ten, to match the Electricity Ten Year Statement (ETYS). Import to embedded electricity storage has been added as it becomes more prevalent.

DRC Schedule 22 (week 2)

The subgroup used the current Schedule 10 as the basis for Schedules 22 and 26. The greatest changes from Schedule 10, are an increase in the forecast period from seven to ten years, and a new row for the aggregate export from all Embedded Power Stations at the forecast half-hourly NETS minimum Demand. The time and date of the NETS minimum Demand will be provided by NESO.

DRC Schedule 23A-C (week 28)

Schedule 23 is based on the current Schedule 11, following many of the same modernisations as Schedule 21. The three sheets of Schedule 23 relate to NETS peak, Connection Point peak, and Connection Point Access Period peak. Schedule 23A and 23B are broadly similar to Schedules 21A and 21-B, whereas Schedule 23C is not.

Schedule 23C contains rows which refer to post-fault operational configurations and running arrangements within the PSM Scenario Document. These rows should contain high level details, whilst the main information will be included in the PSM Scenario Document.

DRC Schedule 24 (week 28)

Schedule 24 is based on the current Schedule 17 and formalises much of the ad-hoc additions that have been made to Schedule 17 since its introduction and reflects the schedule in the current version NESOs guidance to Network Operators. NESO will fill out their view of the planned outage windows which will be reviewed by Network Operators. The period of weeks that can be proposed for planned outages has been increased to include weeks 10-43, and any potential outage clashes are automatically highlighted.

DRC Schedule 25A-C (week 28)

Schedule 25 is based upon the current Schedules 12A, and the DRC table relating to OC6, aiming to formalise the collection of data which has happened outside of the DRC in the past. This data is related to Demand Control and disconnection.

DRC Schedule 26A-B (week 28)

This Schedule is based upon the current Schedule 10 and contains the same updates as the new Schedule 22. Schedule 22 is used to express the half hour measured Demand at both the time of the Network Operator's peak Demand and NETS peak Demand, which will be provided by NESO.

DRC Schedule 27 (week 28)

Schedule 27 is an updated version of the second table in the current Schedule 10. Subgroup members debated as to whether this information was still required by NESO. After some searching within NESO, teams were found which do use this data.

DRC Schedule 28 (week 28)

This Schedule originated as part of CMP434 Final Modification Report (Relevant Embedded Small/Medium Power Stations) but was transferred to GC0139 due to embedded Power Stations no longer being considered in CMP434. Originally this Schedule separated Power Stations and Plant by undefined technology types, but this was altered to Aggregated Energy Sources to coordinate with the rest of the new schedules. Network Operators will fill in forecast aggregated Registered Capacities for each Connection Point for the next ten years.

The first part of Schedule 11 table b is similar to Schedule 28, but with much less detail.

DRC Schedule 29A-B (week 2 and 28)

Schedule 29 is based upon the existing Schedule 11 tables c and d. One difference is that the Sub 1 MW Embedded Power Stations data is collected alongside a unique object RDF ID (Resource Description Framework) contained within the Solved PSM. The list of fuel types has been replaced with Aggregated Energy Sources. Instead of using the Large, Medium, and Small categorisations for Embedded Power Stations, Embedded Power Stations are categorised in to below 1MW and at or above 1 MW so that the outcome of GC0117 would not affect this modification.

The Embedded Power Stations at or above 1 MW Schedule has been expanded to include the location of solar and wind farms. Rather than ask for technology and production type, Schedule 29 asks for the Energy Source and Energy Conversion Technology using drop downs. The details surrounding voltage control mode have been increased to include maximum and minimum Reactive Capability. The last additions are a box to highlight whether the Plant has been connected yet and a box for any extra comments the Network Operator may want to add.

DRC Schedule 30 (week 2 and 28)

Schedule 30 is based upon table b in the current Schedule 11 and has been expanded for ten years of forecast data rather than seven. The first part of Schedule 11 table b is not required in Schedule 30 as it has been covered by Schedule 28.

Legal text

The legal text for this change can be found in **Annex 03**.

The following considerations were taken into account when creating the legal text:

- Work with the ENA's Data & Digitalisation Steering Group: Open Grid Systems (OGS), as CIM subject matter experts, undertook the gap analysis that identified that extensions were needed to meet PC.9 and PC.10 requirements. OGS assisted with changes to PC.9, PC.10 and PC Appendix G.
- GB SQSS Review – GSR029: The Workgroup focused on aligning the GC0139 and GSR029 modifications with the Distribution Code Review Panel's efforts to revise EREC P2. GC0139 has incorporated definitions from the EREC P2 Workgroup into its Glossary and Definitions, and a diagram explaining the Demand related definitions was included in the new Planning Code (PC.9.)
- Mentions of week 24/28 Submissions elsewhere in the Grid Code: The Subgroup discussed how GC0139 would alter the meaning of mentions of week 24/28 in areas of the Grid Code outside of the Planning Code. Changes were made to the legal text, including the European Connection Conditions (ECCs)/ Connection Conditions (CCs)/ Operating Code (OC), DRC, and PC Appendix G (PC.G).
- DRC schedules in Excel format: A new submission area will be added to the NESO website, meaning that there will be two separate places where current versions of the DRC schedules are kept. The impact of this change is minimised by amending the link to the Word version of the document to say schedules 1 – 20 and having the link to the Excel file end with schedules 16, 21 – 30. The Grid Code Review Panel (GCRP) were happy for the Excel file to be published online, providing that it was kept up to date with the current version of the DRC in the Grid Code.

Workgroup considerations

The Workgroup convened 28 times to discuss the issue described in the modification proposal, the scope of the identified defect, devise potential solutions and assess the proposal in terms of the Applicable Grid Code Objectives.

Due to the complexity of the legal text, a subgroup was created to develop the changes to the Planning Code, Glossary and Definitions, and consequential changes to the Data Registration Code. Subgroup meetings were run in addition to Workgroup meetings.

A detailed summary of work considered in the Subgroup meetings and presented back to the Workgroup can be found in **Annex 04**.

Consideration of the Proposer's solution

Data exchange options

The Workgroup considered options which can be found in **Annex 06** relating to the periodic data submission by the Network Operator:

Option 1 – Minimum number of CIM files, augmented with Bulk Supply Point Schedules to reflect all the forecast scenarios

Option 2 – All Cardinal Point Scenarios in CIM files

Option 3 – the use of Steady State Hypothesis (SSH) files which may be used reduce the need to either:

i. present different Demand scenario data in excel spreadsheets (Option 1); or

ii. reduce the number of CIM files that need to be exchanged (Option 2)

Option 4 – Minimum number of CIM files Augmented with GSP Schedules to reflect all forecast scenarios

Both the Proposer and Workgroup members preferred Option 4, and the Workgroup agreed to proceed on this basis.

CIM

The CIM is defined by the International Electrotechnical Commission (IEC) as "an abstract model that represents all the major objects in an electric utility enterprise typically involved in utility operations." It provides a standard way of representing Power System resources as object classes and attributes, along with their relationships. A CIM facilitates the integration of network analysis applications developed independently by different vendors, between entire systems running network applications developed independently, or between an analysis system running network applications and other systems concerned with different aspects of power system operations, such as generation or distribution management.

The Workgroup proposes to adopt the CGMES version of CIM as the data standard for Planning Code information exchanges. CGMES, developed by European Network of Transmission System Operators for Electricity (ENTSO-E), represents the industry standard. In the Ofgem Open Letter in January 2022, Ofgem directed that the data standard for the Long Term Development Statement (LTDS) shall be CGMES (specifically CGMES v.3).

The proposal is that Network Operators and the NESO will exchange CIM format models based on CGMES v.3 (together with the required extensions, as discussed in the following section) that represent Demand/generation scenarios on their systems. The models will be capable of executing power flow and fault flow analysis utilising standard propriety power flow analysis software tools.

The expectation that is that the Grid Code CIM will be based on the CGMES v.3 in the same way as the LTDS is being raised on CGMES v.3 but there will be a separate Grid Code related profile. Grid Code CIM would be based on CGMES v.3 plus Grid Code CIM additions less Grid Code CIM deviations.

Work with the ENA's Data & Digitalisation Steering Group (DDSG)

To exchange all the data fields required by PC.9 and PC.10 will require extensions to the CGMES v.3 profile, in a similar way that the LTDS has required extensions to CGMES v.3 profile. To ascertain the scope of the extensions required for a Grid Code PC CIM profile the Proposer engaged with DDSG CIM Subgroup to commission a gap analysis between the PC.9 and PC.10 requirements, CGMES v.3 and GGMES v.3 with LTDS extensions.

The DDSG established a DDSG CIM Subgroup who subsequently commissioned OGS, as CIM subject matter experts, to undertake the gap analysis. The gap analysis identified that the extensions needed to meet PC.9 and PC.10 requirements will result in a new CGMES CIM profile; an extension to CGMES v.3 but different to that developed for the LTDS. Development of a Grid Code PC CIM profile will be the undertaken by an appropriate CIM Governance body.

OGS assisted with further changes to PC.9, PC.10 and PC Appendix G to ensure the language used was not only appropriate for engineering use but was also suitable for translation into CIM syntax. This element of the work has necessitated several new definitions which are proposed in the Glossary and Definitions.

CIM Governance Arrangements

To implement the proposals of this modification, the Workgroup Subgroup determined the need for a GB CIM Governance Group. The development of a new profile base on the CGMES v.3 and LTDS profiles incorporating new extensions to meeting PC requirements. These extensions will need to be agreed by NESO and all Network Operators and implemented by the relevant software vendors. It is anticipated that any future modifications of the PC requirements will need further extensions to CGMES v.3. Hence there is a requirement for a formal governance arrangement for the application of CIM within GB.

This governance requirement has already been identified by the Workgroup that is implementing the requirements of the Network Operators enhanced LTDS. The LTDS Workgroup has assumed the role of governance body for an interim period however, arrangements are to be implemented to establish an enduring GB governance body that will oversee CIM development in GB and seek international adoption with the International

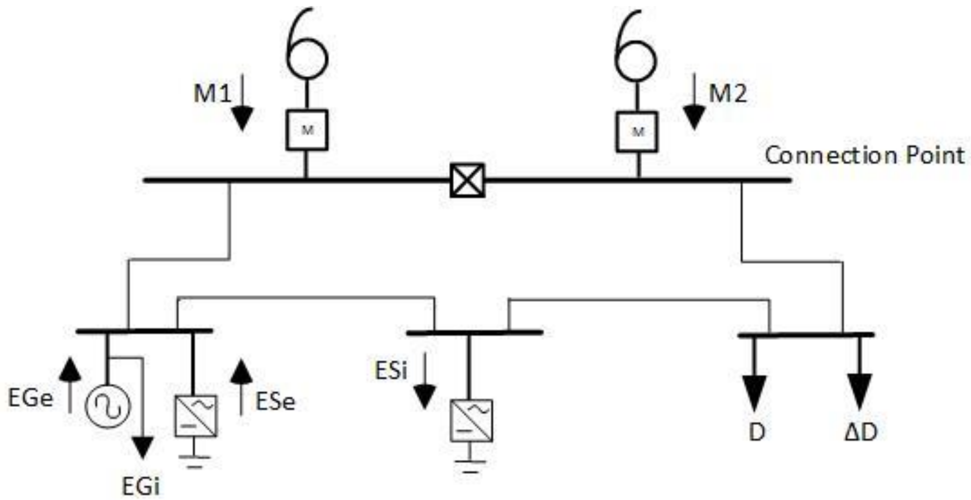
Electrotechnical Commission. This governance body will include representatives from all Network Operators, Transmission Owners, and NESO, along with assistance from CIM industry experts such as Open Grid Systems. GB CIM governance is currently being managed by the British Standards Institute (BSI).

GB Security and Quality of Supply Standard (SQSS) Review – GSR029

The Workgroup was cognisant of the SQSS modification GSR029 Workgroup proposal, to align SQSS with Engineering Recommendation (EREC) P2, Security of Supply. The Subgroup met with members of the GSR029 Workgroup to ensure the GC0139, and GSR029 modifications aligned and that these two proposals also aligned with the Distribution Code Review Panel working group which is looking to revise EREC P2 to exclude the import to electricity storage devices from the security of supply assessment. If is important to ensure that, wherever possible the changes being developed by these three Workgroups are aligned because the issues they address are interrelated. This modification, GC0139, has adopted definitions that aim to align with those developed in the EREC P2 Workgroup, incorporating them into the Glossary and Definitions. PC.9 therefore requires reporting against these definitions, which are: Gross Demand, Group Demand, Latent Demand, Measured Demand, Embedded Power Station Export, and Embedded Power Station Import. These updates were introduced to the Workgroup who were supportive of the proposed definitions.

A stylised diagram of a power system was included in the new PC.9 to explain these Demand related definitions. This can be seen in figure 2.

Figure 2: Stylised diagram of a power system



M1, M2	measurement at the **Connection Point**
EGi	import to **Large Power Stations**, **Medium Power Stations** and **Small Power Stations** other than to **Electricity Storage Module(s)**

EGe	export from **Large Power Stations**, **Medium Power Stations** and **Small Power Stations** other than from **Electricity Storage Module(s)**
ESi	import to **Electricity Storage Module(s)**
ESe	export from **Electricity Storage Module(s)**
D	aggregated **Embedded Customer Import**
∆D	aggregated **Latent Demand** of **Embedded Customers**

Where:

Group Demand = D + ∆D

Group Demand = (M1 + M2) + (EGe + ESe) – (EGi + ESi) + ∆D

Latent Demand = ∆D

Gross Demand = (D + ∆D) + (EGi + ESi)

Embedded Power Station Export = EGe + ESe

Embedded Power Station Import = EGi + ESi

Measured Demand (Net Demand) = M1 + M2

Interaction with CUSC Modification CMP434

During the development of the CMP434 solution, a Schedule, which aimed to gather information on the Registered Capacity of different types of generation, was developed to be included as part of Network Operators submissions related to CMP434. After some debate the CMP434 Workgroup decided that this schedule would be out of scope of their solution, and that GC0139 would be a better place for it to be included. This schedule was the basis for Schedule 28.

Interaction with GC0117

GC0117 is a modification that aims to harmonise the connection requirements so their harmonised across GB. The emerging solution is to unify the size ranges of Small, Medium, and Large Power Stations across all GB regions. The modification has been contentious, taken seven years to develop and was sent back to the GCRP by Ofgem. This Workgroup has now resumed to address Ofgem's feedback with the intention to run the second Code Administrator Consultation in May 2026. During the development of GC0139, it became clear that using the terms Small, Medium, and Large to categorise Power Stations in the Network Operators week 24 submissions could lead to unintended consequences if GC0117 altered these definitions, because the export from Large Power Stations is treated differently to the output form Small and Medium Power Stations. The Subgroup avoided using the terms Small, Medium, and Large where possible and, in terms of reporting on their export all embedded Power Stations are treated in the same way. Hence regardless of the outcome of GC0117, GC0139's outcome would remain as intended.

Mentions of week 24/28 Submissions elsewhere in the Grid Code

The Subgroup discussed how GC0139 would alter the meaning of mentions of week 24/28 in areas of the Grid Code outside of the Planning Code.

European Connection Conditions (ECCs)/ Connection Conditions (CCs)/ Operating Code (OC)2

The references to week 24 in the ECCs, CCs, and OC2 are related to Generators. As GC0139 is about data exchanges between Network Operators and NESO, these references have been left unchanged.

OC5

The references to week 24 are related to Network Operators' annual submissions. The legal text was edited to remove Network Operators from this obligation, and a new clause was added below explaining how before the PSM Implementation Date, this data could be submitted in week 24, whereas after the PSM Implementation Date it could be submitted in week 28.

OC6

All references to week 24 in OC6 relating to Network Operators were altered to week 28. PC.A.1.2 explains that while the requirement for the submission of this data is set at week 24, Network Operators are allowed to defer this submission to week 28. Network Operator members of the Subgroup stated that this allowance is almost always used, so altering the date to week 28 is not a major change. As the new submission date in GC0139 is week 28, changing this legal text now removes the need for a "clean-up" modification to take out references to the PSM Implementation Date in the future.

DRC

As the DRC contains the templates for new schedules, it has the largest amount of changes outside of the Planning Code and the Glossary and Definitions. A description of each of these new schedules was added, along with a new table to explain the schedules that the various parties need to submit before and after the PSM Implementation Date; only those relating to Network Operators are changed by GC0139.

Schedules 10 and 11 will no longer be required to be submitted by Network Operators after the PSM Implementation Date as they are being replaced with more detailed schedules. Schedules 12 and 16 were altered to include a clause that would change what data had to be submitted after the PSM Implementation Date. When reviewing the DRC and the Planning Code, the Subgroup was unable to find any requirements to submit schedule 13. The subgroup therefore did not include a new requirement to submit schedule 13.

Planning Code Appendix G (PC.G)

PC.G can be viewed as an updated, expanded form of the Planning Code's Appendix A which applies to Network Operators after the PDM Implementation Date. The decision was made for the new Planning Code sections, PC.9 and PC.10 to contain a high-level overview of submissions, with the majority of the detail contained within PC.G. Detailed guidance relating to how to comply with a Grid Code obligation is not typically included in the Grid Code, but the Subgroup felt this approach was better than relying separate ungoverned NESO guidance notes. The use of guidance notes has led to debates on whether the requirements in the Grid Code do or do not apply, as well as confusion on interpretation of the Grid Code requirements. To avoid these issues, the Subgroup have explained the new requirements and provided some background information in PC.G.

PSM Implementation Date

The term PSM Implementation Date, which is the date that the new changes within GC0139 will come into effect, has been added to the Glossary and Definitions. The provisional date is set as the first of January 2027, unless NESO and the Network Operators agree that they are not ready to implement the changes. In this case, the PSM Implementation Date will be deferred to a more suitable date agreed by relevant parties.

During the Workgroup Consultation, six of the seven respondents stated that they did not believe the previously proposed PSM Implementation Date, the first of January 2026, was practically achievable.

Implementation costs

The NESO's estimated costs are outlined in **Annex 05**.

Network Operators are already working to implement the requirements of CIM in the context of the Long-Term Development Statement (Distribution SLC25). It is estimated that implementation costs of GC0139 will partly be covered by the ongoing work on the Long-Term Development Statement. Annual preparation and reporting costs may increase compared to the current PC data preparation, submission and reporting costs.

The Workgroup acknowledged the need for trial data exchanges between Network Operators and NESO, in preparation for the changes required to implement the proposed CIM data exchange, suggesting the creation of a new NESO – Network

Operator working group to coordination the implementation activities, assuming that the modification proposal is authorised by the Authority.

Consideration of how new Schedules are shared and governed

The newly created Excel based schedules are larger and more complex than existing schedules. This difference has led to issues representing these schedules properly within the DRC, where schedules are pasted in as images of the tables in the schedules. In addition to being included in the Portable Document Format (PDF) and online versions of the Grid Code, the DRC is posted on the NESO website as a Word document as well as a PDF, so that relevant parties can access and complete the DRC schedules more easily. This approach works when the schedules are small and have no internal calculations. The Workgroup recognised that

presenting the new DRC schedules in a PDF or Word document would not be particularly helpful.

The Workgroup sees two potential solutions for this problem.

Option 1: *Simplify the new schedules and remove all internal calculations from them.*

This option would allow the new DRC schedules to be presented in the form of simple word of PDF documents that would be includes in the separately published DRC

However, selecting this option would mean that dropdown menus and internal checks with the new schedules would have to be removed, making the schedules harder to fill in and increasing the chance of errors during submissions. An example of a useful internal check is in Schedule 24, where overlapping access periods are highlighted to show potential clashes.

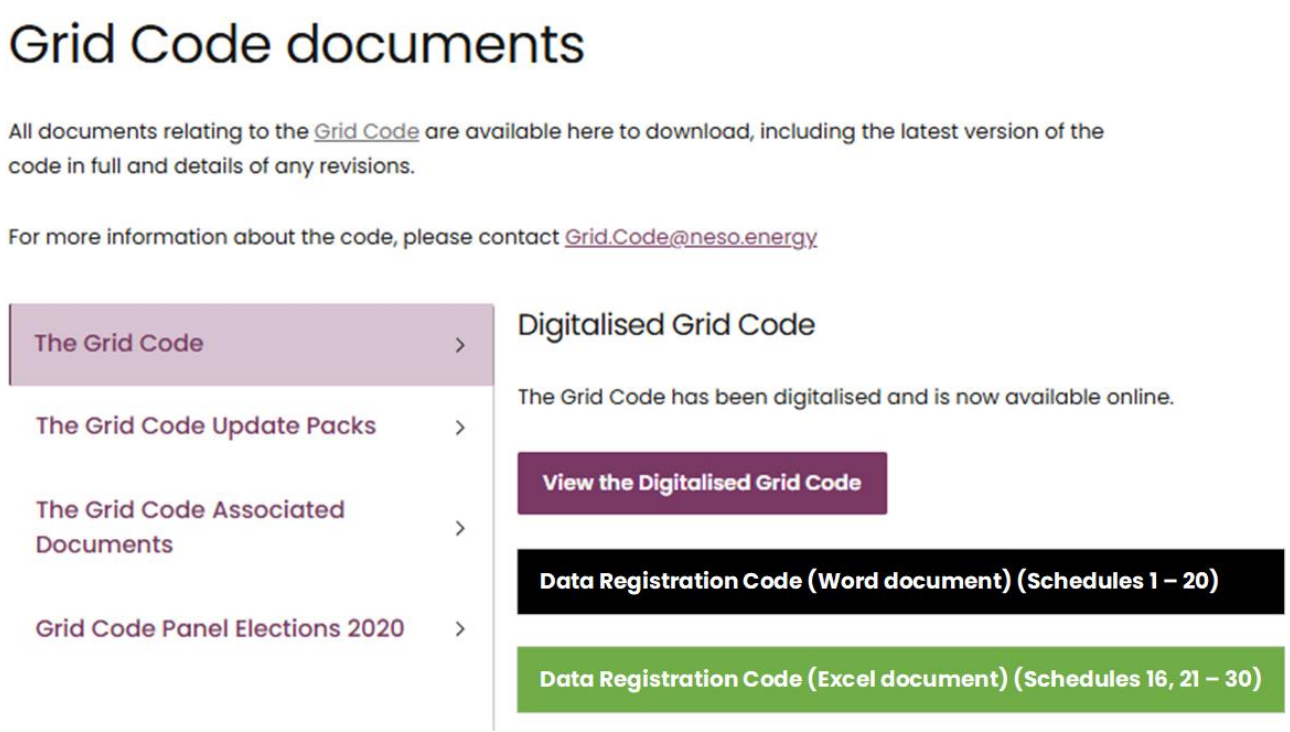
NESO would also have to dedicate more time to mapping the six different sets of submissions into one format, as Network Operators might submit them with in slightly different formats.

Option 2: *Create a new section on the NESO Grid Code website where the new schedules in Excel format can be posted.*

This option would allow for more useful schedule files to be shared, meaning Network Operators could fill them in easier and NESO would be able to process them faster. NESO would have to spend less time accounting for format differences between submissions.

The downside of this option is that a new submission area would have to be added to the NESO website, effectively meaning that there would be two separate places where current versions of the DRC schedules are kept. The impact of this change could be minimised by amending the link to the Word version of the document to say schedules 1 – 20 and having the link to the Excel file end with schedules 16, 21 – 30.

Figure 3: Mock-up of Option 2 Implementation



There was discussion within the Workgroup about whether Option 2 would be allowed within the Grid Code rules. If it were allowed, who would have to make that decision, the Workgroup or Panel. Option 2 was preferred by the Subgroup, but NESO Legal would have to be consulted to determine if it was legally sound.

The NESO representative consulted with the Legal Team, who stated that the Excel file can be published on the NESO website with an obligation on NESO, within the Grid Code, to publish and update the Excel template, with a corresponding obligation on Network Operators to use the Excel template. GCRP were happy for the Excel file to be published online, providing that it was kept up to date with the current version of the DRC in the Grid Code. Below is a section from the Grid Code regarding the use of electronic formats:

DRC.5.2.3 Where a computer data link exists between a **User** and **The Company**, data may be submitted via this link. **The Company** will, in this situation, provide computer files for completion by the **User** containing all the data in the corresponding **DRC** schedule.

Data submitted can be in an electronic format using a proforma to be supplied by **The Company** or other format to be agreed annually in advance with **The Company**. In all cases the data must be complete and relate to, and relate only to, what is required by the relevant section of the **Grid Code**.

The NESOTechnical Codes team attended the September 2025 GCRP to discuss the governance arrangements for changes made to the Excel files. Panel members felt that changes to the excel schedules should probably follow normal Grid Code governance.

This solution is on an interim basis due to possible full DRC digitalisation, which currently only includes Generators and not Network Operators.

Terms of Reference discussion

a) Implementation and costs

Network Operators

It was agreed following Workgroup Consultation that more granular costs were required and the Workgroup agreed to complete a cost proforma to provide this information. This proforma was sent out to Workgroup members and 6 responses were received.

Costs for the initial implementation of the CIM models and data exchange averaged around £199,000 per Network Operator. Extrapolating this number to all licenced and operational Network Operators gives a total year one implementation cost of £1.19M.

There are a few reasons for the variance in initial costs between Network Operators. One of the reasons is that some need to purchase new software while others do not. Another reason is that some Network Operators need to update their network models to be compatible with CIM, whereas others are already using CIM compatible models. Some Network Operators will have to recruit staff who are familiar with CIM in order to fill a gap in their knowledge.

Costs for the annual maintenance of the CIM models and data exchange averaged around £89,000 for each of the six existing Network Operator. Extrapolating this number to all licenced and operational Network Operators gives a total annual cost of £532,000.

These expected costs relate to the six licenced and operational Network Operators and does not take into consideration future Network Operators.

Should any of these future Network Operators connect before this modification is implemented, they will have to implement the current Planning Code data exchange methodology and then invest on meeting this modification’s change to the Planning Code data exchange process. A Network Operator who commissions after the implementation date of this modification would only have to develop the capability to exchange Planning Code data as to this modification.

NESO

Expected costs, both initial and annual, were provided from NESO. Part of the costs for NESO comes from the development and upkeep of the electricity Management of Interface Data System (eMIDS), which will be used to allow Network Operators and Transmission Owners to exchange interface data. The initial set up costs for eMIDS is expected to be around £120,000 with £45,000 being spent annually on upkeep.

The other major contributor to NESO's costs is the development of new Offline Transmission Analysis (OLTA) tools that can integrate CIM files. This development includes the creation of new business processes to allow NESO to meet the new Planning Code obligations under GC0139. The initial set up costs for OTLA is expected to be around £250,000 with £45,000 being spent annually on upkeep.

NESO will also have to support GB CIM Governance and assist with the transition to a BSI lead group, which is expected to cost £45,000 initially and £20,000 annually.

The total initial expected cost for NESO is £415,000 and the expected annual cost is £90,000. Much of the changes needed for NESO to implement GC0139 are already being undertaken as part of wider system modernisation such as under the Long Term Development Statements (LTDS), so these costs cannot be fully attributed to GC0139. A more detailed breakdown of NESO's costs can be found in **Annex 05**.

b) Review draft legal text should it have been provided. If legal text is not submitted within the Grid Code Modification Proposal the Workgroup should be instructed to assist in the developing of the legal text

The main focus of the Subgroup has been to develop the legal text before further development with Workgroup. The final legal text can be found in **Annex 03**.

c) Consider whether any further Industry experts or stakeholders should be invited to participate within the Workgroup to ensure that all potentially affected stakeholders have the opportunity to be represented in the Workgroup. Demonstrate what has been done to cover this clearly in the report

Two industry experts from Open Grid Systems were consulted during the development of GC0139 to ensure that the requirements set out were compatible with both CIM and power system modelling software that is available on the market. This can be found in 'Work with the ENA's Data & Digitalisation Steering Group (DDSG)' sub-heading on page 16.

The Workgroup acknowledged the need for ongoing engagement between Network Operators and NESO to facilitate trial data exchanges. This coordination would be vital for ensuring that all parties are prepared for the PSM implementation date. There was a suggestion from Workgroup to form a new working group that would oversee this implementation coordination post-approval.

d) Be aware of and consider cross code impacts, and consider co-ordinate submission and implementations

Further details on considerations made by the Workgroup can be found above in 'Workgroup Considerations, 'GB Security and Quality of Supply Standard (SQSS) Review' sub-heading on page 17. 'Interaction with GC0117' sub-heading on page 19, as well as consideration of CUSC modifications CMP298, CMP328 and CMP434 in the 'Interactions' section on page 36.

e) Consider EBR implications

The Workgroup agreed that the modification will necessitate changes to the DRC. However, whilst the proposed changes will have an interaction with the EBR (the regulated sections of the Grid Code make reference to the DRC). The Workgroup are of the view that whilst there may be an interaction there are no impacts on the Electricity Balancing Regulation (EBR) objectives because the DRC schedules this modification proposes to change, don't have implications for the Article 18 Terms and Conditions (T&C's) which apply to balancing providers. Respondents to the Workgroup consultation agree this to be the case. However, in accordance with the rules of the EBR, the GC0139 Code Administrator Consultation will run for a month.

f) Consideration of any unintended consequences of effectively redefining the observability area

The Workgroup reviewed whether Articles 40-52 of the EU Regulation System Operation Guideline (SOGL) impact Observability Area in particular the impact of this change which is increasing the structural data requirements being imposed on Network Operators. The Workgroup further considered how the extension in structural data may impact Network Operators requirements around real-time data provision, particularly in the context of Network Operators and power generating modules. The implementation of these articles was addressed by GC0106. It was concluded that NESO has flexibility in interpreting certain articles, but since GC0139 is not about real-time data, and focusses on exchanging planning (structural and scheduled) data, there are no unintended SOGL consequences. Any future needs for additional asset information in the observability area would require a separate Grid Code Modification Proposal. Further information can be found in **Annex 09**.

g) Consider the Ofgem Letter of 10 January 2022

The Ofgem letter calls for CIM to be used as the standard method of data exchange within GB, starting with LTDS. The Workgroup has followed this approach by using CIM and recognising the need for a CIM governance group after implementation. The Ofgem letter mentions GC0139 within its section "Further application of the CIM".

h) Consider any implications of GC0117

Further details on considerations made by the Workgroup can be found above in 'Workgroup Considerations' section 'Interaction with GC0117' sub-heading on page 19.

i) Consider any temporary governance arrangements required prior to any formal governance being in place

The Workgroup considered the development of a working group to facilitate the change should GC0139 be approved. It was agreed that future governance should be developed further by the BSI. This can be found under 'Workgroup Considerations' section, 'CIM Governance Arrangements' on page 17.

Workgroup Consultation Summary

The Workgroup held their Workgroup Consultation between 17 December 2025 and 21 January 2025 and received 7 responses. The full responses and a summary of the responses can be found **Annexes 07 and 08** respectively.

Following the Workgroup Consultation the Subgroup and Workgroup reconvened to discuss the responses and discussed the following:

Implementation Approach

Six respondents supported the implementation approach with the following points being noted:

- Support may be required prior to implementation for parties unfamiliar with power system modelling, such as Independent Distribution Network Operators (IDNOs) with assets directly connected to the Transmission System; and
- One respondent noted that the benefits of the modification are unlikely to be realised immediately after implementation

Workgroup feedback: Some Workgroup members stated in their response that they believe the biggest barrier to the implementation is the date. Since the consultation, the PSM implementation date has been moved back a year to the 01 of January 2027. One member stated that the lack of specified CIM profiles could cause issues, the Subgroup believes this issue will be resolved by the CIM governance group.

Legal Text

Six respondents agreed that the legal text did satisfy the intent of the modification. However, a number of legal text changes were suggested, including:

- PC.G was reworked to better fit current power system modelling software
- PC.G.7 was expanded to better describe Connection Points and Access Groups
- Relevant mentions of week 24 in the Grid Code outside of the Planning Code were updated
- Submission date for schedule 22 was moved to week 2
- Aggregated Energy Source and Energy Conversion Technology tables were reworked; and
- The submission timeline figure was reworked to be easier to understand

Workgroup feedback: Some Workgroup members wanted greater clarification and guidance within the legal text, which the Subgroup believes has been provided with the expansion of PC.G. Other members provided feedback using comments on the legal text. The Subgroup used these comments to improve the legal text.

Consideration of Option 4

Six respondents agreed that Option 4 represents the best solution to providing an enhanced data exchange without a significant increase in the number of forecasting schedules exchanged. One respondent noted that they felt the Workgroup could provide better input on this.

Workgroup feedback: The Workgroup initially looked at extending the current data exchange methodology of spreadsheets to exchange switch level models. After this method was deemed inefficient, the Workgroup then had to decide on going down a specified software route or a software agnostic data exchange like Common Information Model (CIM). The Workgroup and Proposer showed preference for a minimum number of CIM files Augmented with GSP Schedules to reflect all forecast scenarios.

Alignment with GSR029

Five respondents agreed that the risk of PC annual exchanges not being aligned with the existing SQSS requirements was minimal, and that these could be managed on an ad-hoc basis. One respondent was unsure, and one did not agree.

- Workgroup agreed that there was interaction between GSR029 and GC0139 but felt that this should not delay progress.
- Discussion took place with the Proposer of GSR029 and it was agreed that the progress of each modification would be considered and that the definitions for Gross Demand, Group Demand, Latent Demand, Measured Demand, Embedded Power Station Export, and Embedded Power Station Import should be aligned with the emerging thinking of GSR029

Workgroup feedback: The Workgroup agreed that as long as the definitions were with the emerging thinking of GSR029 this should not impact progress of GC0139.

Annual Planning Data exchange

Respondents considered the position of the Workgroup that this modification proposal relates to annual planning data exchanges only. The provision of data to support a new connection (PC.4) will remain unchanged and not directly supported with CIM models. This is because the data requirements within PC.4 are not covered by CGMES v3 and would require significant extensions not justified by the benefits. All seven respondents agreed with this approach.

Workgroup feedback: Some Workgroup members stated that altering PC.4 would be considered scope creep for GC0139.

Delivery Timescales

Six respondents did not believe that the delivery timescale of January 2026 to transition to a CIM data exchange methodology was reasonable and practically achievable. Since the Workgroup Consultation, the PSM Implementation Date has been altered to January 2027, and could be altered further if the relevant parties are not able to meet the PSM Implementation Date.

Workgroup feedback: Workgroup members stated that the alteration of PSM Implementation Date would allow software vendors, Network Operators, and NESO to better prepare for implementation. Workgroup members also expressed concern about beginning implementation without a GB CIM governance group.

Implementation Costs

Six respondents envisaged that there would be costs incurred to implement the proposal over and above any changes associated with implementing other CIM data exchanges and those associated with the existing data exchanges. One respondent felt that this was possibly the case.

Respondents felt that these costs would relate to software and staff upskilling/additional labour and process changes. To collect data on this subject a cost proforma was created and shared with the Workgroup, as can be seen in Term of Reference a), and **Annex 05**.

Workgroup feedback: Some Workgroup members asked for more detail on implementation costs. A cost proforma was created and shared with the Workgroup, which received 6 responses. Workgroup members believe that extra costs will be incurred during the updating of network models and the trialling of data exchanges.

Consideration of other solutions

The early work considered an expansion of the current spreadsheet-based data exchange methodology using spreadsheets to exchange switch level models. This option was rejected as requiring too much individual business development to both populate and consume the data on an initial basis. Funds would need to be regularly allocated to deal with changes. The Workgroup then debated if a specific power system modelling software should be selected or if a software agnostic data exchange standard should be used. It was decided that the most efficient way to exchange the enhanced data reporting requirements would be through the exchange of PSMs in CIM format.

CIM was selected to be vendor agnostic to give all parties the flexibility to use their preferred system modelling application that met their wider business requirements. The Workgroup recognised that some Network Operators do not currently use modelling applications that have CIM capability and that implementation would require a phased approach over several years. NESO and Network Operators have, or will soon have, other reporting requirements in CIM format, and hence will need to ensure they use platforms with CIM capability. Development of the CIM, specifically with the required CGMES v.3 extensions represent IT expenditure; the use of CIM provides flexibility for stakeholders to select modelling forms that best integrate with other relevant corporate IT systems.

During the initial stages of the proposed change, solutions discussed by the Workgroup was to:

- expand the Grid Code Planning Code (PC) obligations placed on Network Operators to include an enhanced level of planning data exchange and to retain the existing Excel Workbook format; and
- expand the PC obligations placed on NESO to include an enhanced level of planning data exchange in an Excel Workbook format.

This solution could be implemented immediately, without the need to develop a CIM data exchange process, but was seen as highly inefficient and overly burdensome, particularly for NESO. Therefore, this was not formally raised as an alternative.

No formal alternatives were raised.

Terms of Reference Overview

a) Implementation and costs It was agreed following Workgroup Consultation that more granular costs were required and the Workgroup agreed to complete a cost proforma to provide this information. This proforma was sent out to Workgroup members and 6 responses were received. The implementation and maintenance costs for the CIM for Network Operators are significant, averaging £199,000 for initial setup and £89,000 for annual maintenance per operator. This results in estimated total costs of £1.19 million for year one and £532,000 annually across all licensed operators. Variances in costs arise from factors like the need for new software and staff training. NESO has estimated initial costs of £415,000 and annual costs of £90,000, which include expenses for developing the eMIDS and OLTA tools. Although some costs are tied to existing system modernisation efforts, detailed financial breakdowns are available in **Annex 05**.
b) Review draft legal text should it have been provided. If legal text is not submitted within the Grid Code Modification Proposal the Workgroup should be instructed to assist in the developing of the legal text

A Subgroup was formed to develop the legal text before further development with Workgroup. The final legal text can be found in **Annex 03**.
c) Consider whether any further Industry experts or stakeholders should be invited to participate within the Workgroup to ensure that all potentially affected stakeholders have the opportunity to be represented in the Workgroup. Demonstrate what has been done to cover this clearly in the report Two industry experts from Open Grid Systems were consulted during the development of GC0139 to ensure that the requirements set out were compatible with both CIM and power system modelling software that is available on the market. The Workgroup acknowledged the need for ongoing engagement between Network Operators and NESO to facilitate trial data exchanges.
d) Be aware of and consider cross code impacts, and consider co-ordinate submission and implementations The Workgroup was aware of the SQSS modification GSR029 and to align SQSS with the EREC P2. The Subgroup met with members of the GSR029 Workgroup to ensure the GC0139 and GSR029 modifications aligned. The Workgroup took GC0117 into consideration and the Subgroup avoided using the terms Small, Medium, and Large where possible and, in terms of reporting on their export, all embedded Power Stations are treated in the same way.
e) Consider EBR implications Whil the proposed changes will have an interaction with the EBR. The Workgroup are of the view that there are no impacts on the EBR objectives. Respondents to the Workgroup consultation agree this to be the case.
f) Consideration of any unintended consequences of effectively redefining the observability area The Workgroup reviewed whether Articles 40-52 of the EU Regulation System Operation Guideline (SOGL) would impact the Observability Area. It was concluded that NESO has flexibility in interpreting certain Articles, but since GC0139 is not about real-time data, and focusses on exchanging planning (structural and scheduled) data, there are no unintended SOGL consequences. Further information can be found in **Annex 09**.
g) Consider the Ofgem Letter of 10 January 2022 The Ofgem letter mentions GC0139 within its section "Further application of the CIM". The Workgroup recognised the need for a CIM governance group after implementation.

h) Consider any implications of GC0117 The Workgroup considered the implications as part of Term of Reference d).
i) Consider any temporary governance arrangements required prior to any formal governance being in place It was agreed that future governance should be developed further by the BSI.

What is the impact of this change?

Original Proposer’s assessment against Grid Code Objectives	
Relevant Objective	**Identified impact**
i) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the Transmission of electricity;	**Positive** Reduces the time necessary to interpret data exchanges into working models and allows more detailed models than current methods allow.
ii) To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity Transmission System being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);	**Positive** Accurate network models and alignment with ETI will enable efficient offers for generation and Demand connections.
iii) Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, Transmission and distribution systems in the national; and	**Positive** Enables more detailed models than current methods allow which should enable the system operator to reduce uncertainty.

iv) To efficiently discharge the obligations imposed upon the licensee by this licence* and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency. In conducting its business, the Workgroup will at all times endeavour to operate in a manner that is consistent with the Code Administration Code of Practice principles.	**Positive** Enables a more efficient exchange of information between licensees.
v) To promote efficiency in the implementation and administration of the Grid Code arrangements.	**Neutral** Implementation and administration of the Grid Code arrangements will remain unchanged by these proposals.

* See Electricity System Operator Licence

Workgroup Vote

The Workgroup met on 20 November 2025 to carry out their Workgroup Vote. The full Workgroup Vote can be found in **Annex 11**. The table below provides a summary of the Workgroup Members view on the best option to implement this change.

For reference the Applicable Grid Code Objectives are:

i. *To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity*
ii. *Facilitating effective competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);*
iii. *Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole;*
iv. *To efficiently discharge the obligations imposed upon the licensee by this license* and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and*
v. *To promote efficiency in the implementation and administration of the Grid Code arrangements*

** See Electricity System Operator Licence*

The Workgroup concluded unanimously that the original better facilitated the Applicable Objectives than the baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	7

Code Administrator Consultation Summary

The Code Administrator Consultation was issued on 06 January 2026 and closed on 06 February 2026 and received 8 non-confidential responses and 0 confidential responses. A summary of the responses can be found in the table below and in **Annex 14**, and the full responses can be found in **Annex 15**.

Code Administrator Consultation summary	
Question	
Do you believe that the GC0139 Original Proposal better facilitates the Grid Code Applicable Objectives?	The following numbers of respondents believed the original proposal better facilitates each Grid Code Applicable Objective: 7 for (i), 3 for (ii), 7 for (iii), 5 for (iv) and 6 for (v). Seven respondents supported the solution as it improves transparency and standardisation in network data exchange, especially using CIM and GC0139-aligned models. One respondent noted that greater network visibility strengthens system planning, clarifies network interactions, and enables more efficient, coordinated operations. One respondent did not believe that any of the applicable objectives better facilitates the solution.
Do you support the proposed implementation approach?	Seven respondents supported the implementation approach.

	Four respondents found the deadline unrealistic, with one respondent suggesting September 2027 as a better option. One respondent has concerns for the need for agreed profiles and unclear vendor requirements. Two respondents did not support the implementation approach. The one respondent felt the solution is not defined or robust and potentially not achievable. The other respondent did not support the January 2027 implementation date and highlighted several risks. They recommended a January 2028 implementation date.
Do you have any other comments?	One respondent highlighted the need for strong governance for TOs amid planning changes. One respondent raised concerns about cost implications of the data exchange model. One respondent stated that implementing GC0139 and LTDS CIM requires CGMES v3.0 extensions and collaboration, with potential future adjustments needed for LTDS or the Grid Code. One respondent stated that NESO faces quality control challenges managing 14 CIM files. One respondent commented on several key issues they believe are unresolved. They noted the implementation timeline issue, they feel the plan lacks a trial period and that there is decreased accuracy with the CIM. They find the solution does not specify required extensions, and have concerns about software vendors' readiness and unclear costs. They state there are ongoing technical challenges from LTDS CIM, and they feel the guidance on transitioning from

	spreadsheets to CIM Power System Models is unclear.
Legal text issues raised in the consultation	
One respondent had three queries related to the GC0139 legal text document Planning Code. These comments and the NESO response can be found in **Annex 16**.	
EBR issues raised in the consultation	
No EBR issues were raised	

Panel Recommendation

The Panel will meet on 26 February 2026 to carry on their recommendation vote.

They will assess whether a change should be made to the Grid Code by assessing the proposed change against the Applicable Objectives.

Panel comments on Legal text

Ahead of the vote taking place, the Panel will consider the legal text amendments proposed as part of the Code Administrator Consultation and agree next steps. The suggested changes can be found in **Annex 16.**

When will this change take place?

Implementation date

10 Business Days after the Authority decision, with the new obligations taking effect from 01 January 2027.

Date decision required by

Before 01 January 2027.

Implementation approach

GB CIM Governance Group to define CIM profile to facilitate this data exchange. This process involves Network Operators, NESO and all affected parties by means of bilateral working between NESO and Network Operators and relevant TOs to facilitate the implementation of this planning data exchange process.

Interactions

☒CUSC	☐BSC	☒STC	☒SQSS
☐European Network Codes	☒ EBR Article 18 T&Cs1	☒Other modifications	☒Other

STC

There may need to be consequential changes made to the STC following this modification. It is therefore proposed that any change arising from this Grid Code modification will have to be acknowledged within STCP 22-1 Production of Models for GB System Planning.

Notification will be made to the STC Panel so that the necessary consequential changes can be made.

CUSC

Consideration was given to the following three CUSC modifications which have now concluded:

- CMP298: Updating the Statement of Works process to facilitate aggregated assessment of relevant and collectively relevant embedded generation
- CMP328 – Connections Triggering Distribution Impact Assessment
- CMP434 - Implementing Connections Reform

Grid Code

Consideration was given to the following Grid Code modification:

- GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Station requirements

SQSS

Consideration was given to the following Grid Code modification:

- GSR029: Review of Demand Connection Criteria to Align with EREC P2/7 - Various Demand definitions

- Distribution Standard Licence Condition 25 (SLC25) requires Network Operators to publish a Long-Term Development Statement inclusive of PSM in CIM format.

Acronyms, key terms and reference material

Acronym / key term	Meaning
BSC	Balancing and Settlement Code
BSI	British Standard Institute
BSP	Balancing Service Provider
BCA	Bilateral Connection Agreement
CGMES	Common Grid Model Exchange Standards
CIM	Common Information Model
CUSC	Connection and Use of System Code
CMP	CUSC Modification Proposal
DDSG	Data and Digital Steering Group
DRC	Data Registration Code
DER	Distributed Energy Resource
DNO	Distribution Network Operator
EBR	Electricity Balancing Regulation
EREC	Engineering Recommendation
ETI	Evaluation of Transmission Impact
GB	Great Britain
GC	Grid Code
GCRP	Grid Code Review Panel
GSP	Grid Supply Point
HVDC	High Voltage Direct Current

IDNO	Independent Distribution Network Operator
IEC	International Electrotechnical Commission
LTDS	Long Term Development Statement
NETS	National Electricity Transmission System
NESO	National Energy System Operator
OGS	Open Grid Systems
PC	Planning Code
PDF	Portable Document Format
PSDM	Power System Difference Model
PSM	Power System Model
RDF	Resource Description Framework
SLC25	Standard Licence Condition 25
SOGL	System Operation Guideline
SQSS	Security and Quality of Supply Standards
SSH	Steady State Hypothesis
STC	System Operator Transmission Owner Code
T&Cs	Terms and Conditions
TO	Transmission Owner

Reference material

- Open Networks Workstream 1B Product 4 report: Data Exchange in Planning Timescales; Data Scope – Final Report (22 pages)
- Enhanced Schedule 11 (Excel workbook with 5 spreadsheets)
- Schedule 5 – Enhanced Node Data V2 (Excel workbook with 4 spreadsheets)
- Ofgem Open Letter - The CIM regulatory approach and the Long Term Development Statement (10 January 2022)

Annexes

Annex	Information
Annex 01	GC0139 Proposal Form
Annex 02	GC0139 Terms of Reference
Annex 03	GC0139 Legal Text
Annex 04	GC0139 Consultation Presentation Slides
Annex 05	GC0139 NESO Costs and Implementation
Annex 06	GC0139 Data Exchange Option
Annex 07	GC0139 Workgroup Consultation responses
Annex 08	GC0139 Workgroup Consultation summary
Annex 09	GC0139 SOGL Observability Area
Annex 10	GC0139 Data Exchange Timeline
Annex 11	GC0139 Workgroup Vote
Annex 12	GC0139 Workgroup Attendance Record
Annex 13	GC0139 Workgroup Action Log
Annex 14	GC0139 Code Administrator Consultation response summary
Annex 15	GC0139 Code Administrator Consultation responses
Annex 16	GC0139 Summary of Legal Text queries raised through Code Administrator Consultation