



**GRID CODE
CONSULTATION DOCUMENT**

**Grid Code Requirement for Forecast Generation
Output for Embedded Exemptable
Large Power Stations**

The purpose of this document is to consult on the above Grid Code Modification Proposal with Authorised Electricity Operators liable to be materially affected by the proposed changes and forms the basis of the subsequent Report to the Authority

Consultation Ref	E/08
Issue	1.0
Date of Issue	31 st October 2008
Responses required by	28th November 2008
Prepared by	National Grid

DOCUMENT LOCATION

National Grid website:

<http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/>

DISTRIBUTION

Name	Organisation
AEO's	Various
GCRP Members/Alternates	Various
Interested Parties	Various
National Grid Website	

A. INTRODUCTION

1. Paragraph 2 of Condition C14 of the Transmission Licence granted to the National Grid Electricity Transmission plc ("National Grid") provides that National Grid shall, in consultation with Authorised Electricity Operators liable to be materially affected thereby, periodically review the Grid Code and its implementation. That paragraph also requires National Grid, following such review, to send to the Authority:-
 - (a) a report on the outcome of such review;
 - (b) any proposed revisions to the Grid Code as National Grid (having regard to the outcome of such review) reasonably thinks fit for the achievement of the objectives set out in sub-paragraph (b) of Condition C14 of the Transmission Licence; and
 - (c) any written representations or objections from Authorised Electricity Operators (including any proposals by such operators for revisions to the Grid Code not accepted by National Grid in the course of the review) arising during the consultation process and subsequently maintained.
2. This review examines an inconsistency in the way generation is modelled in the DC Load Flow Incremental Cost Related Price (DCLF ICRP) Transport Model and proposes formally codifying the current ad-hoc data submission arrangements between National Grid and the applicable parties within the Grid Code.
3. The proposed changes to the Grid Code were discussed with the Grid Code Review Panel (GCRP) on 15th May 2008. Panel Members agreed that National Grid should issue a Consultation Paper regarding the proposed changes.
4. Comments upon the proposed changes within this consultation should be sent to National Grid by **28th November 2008** as detailed in section C. The comments will be reviewed and responded to.
5. Following this consultation, National Grid will prepare a Report to the Authority detailing National Grid's recommended changes to the Grid Code and all comments/responses received from Authorised Electricity Operators through this consultation. Once sent to the Authority this report will be made available on National Grid's website.
6. Where Authorised Electricity Operators' responses have been marked as confidential they will not be published within the version of the Report to the Authority placed on the National Grid website.
7. The revisions to the Grid Code proposed by National Grid and sent to the Authority, require approval by that body and will, if approved, come into force on such date (or dates) of which you will be notified by National Grid, in accordance with the Authority's approval.

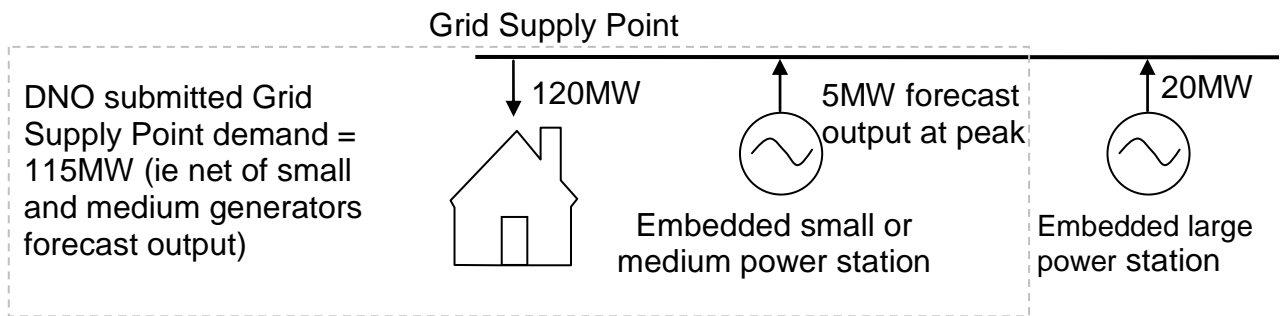
B. DESCRIPTION OF THE PROPOSED AMENDMENTS AND THEIR EFFECTS

8. Background

8.1 The locational element of Transmission Network Use of System (TNUoS) charges is calculated using the DCLF ICRP Transport Model. The transport model is a DC load flow based on the data from the Seven Year Statement (SYS). However there is an additional data requirement for the forecast generation output at GB Transmission System peak demand for embedded exemptable large power stations that is not contained in the SYS or currently obtained through the Grid Code. This is explained below.

8.2 Within the transport model chargeable¹ generation is modelled discretely. Embedded generators that are licencable (>100MW) and have a Bilateral Embedded Generation Agreement (BEGA) with National Grid are chargeable. Therefore embedded generators, greater than 100MW are modelled discretely.

8.3 Within the transport model demand data comes from the SYS². The SYS demand information is submitted by the Distributed Network Operators (DNOs) via the Week 24 data process outlined in Planning Code section of the Grid Code. Within the data submission, the forecast generation output at GB Transmission System peak demand of small and medium power stations is netted from the grid supply point demand (see diagram below). However the DNO forecast output from embedded exemptable large power stations are specifically excluded. See diagram below.



8.4 The current Week 24 data submission obligations for DNOs results in a data anomaly for embedded exemptable large power stations in Scotland due to the regional differences in the Grid Code definition of Large Power Station which are applicable across the GB Transmission System.

8.5 In England and Wales the definition of Large Power Station is a power station which has a Registered Capacity of 100MW or more. Therefore all embedded generators greater than 100MW are chargeable and modelled discretely. Embedded generators under this threshold are netted off by the DNO from their demand submission. Therefore all generation in England and Wales is modelled.

8.6 In Scotland the definition of a Large Power Station is different from England and

¹ Chargeable generation is generation parties liable for generation charges.

² SYS Demand data is taken from the SYS Appendix E.

Wales and is regionally defined³. Large embedded generators which are 100MW (or more) in size are modelled explicitly as they are chargeable. Small power stations are netted off from the DNO demand submission. However embedded exemptable large power stations less than 100MW in size (irrespective of their actual agreement type with National Grid⁴), are neither modelled explicitly nor included in the demand data.

- 8.7 This data omission, currently rectified through ad-hoc arrangements between National Grid and the affected parties, would result in disparities in the way in which embedded generators across the GB Transmission System are treated and modelled.
- 8.8 Therefore the forecast generation output at GB Transmission System peak demand figure is requested on an informal basis and utilised in ICRP Transport Model for embedded exemptable large power stations located in Scotland. This ensures that consistency is maintained throughout the charging model for generation of this size and type across the GB Transmission System.
- 8.9 The data is included in the transport model as negative demand. This ensures that similar sized generators are modelled consistently independent of their location on the GB Transmission System. For example, a 60MW BEGA power station in England and Wales will be represented in the transport model in a similar manner to one located in Scotland which is important in ensuring equality to all Users.
- 8.10 Treating embedded exemptable large power stations as negative demand aligns with the financial treatment of such generators which receive a negative demand credit through TNUoS. As is evident from the table below, there is significant generation capacity that is treated as negative demand. Therefore the treatment of such generation will impact the final spread of TNUoS tariffs. Given the potential impact on TNUoS tariffs it is important that the data used is accurate and consistent.

Demand Zone	Zonal Demand ⁵ (MW)	Total registered capacity (MW) ⁶
SHEDL	1,249	1,068
SPD	4,392	331

9. Proposed Grid Code Changes

- 9.1 It is proposed to amend the Grid Code such that there is consistency in the way generation is modelled in the DCLF ICPR Transport Model by addressing and rectifying the impact of the regional differences in the definition of Large Power Station which exists within the Grid Code.
- 9.2 Since the implementation of the British Electricity Trading and Transmission Arrangements (BETTA) National Grid has requested from the DNOs the forecast

³ The threshold for a large power station in SHETL's Transmission Area is 10MW and in SPPL's Transmission Area is 30MW.

⁴ Both BEGAs and BELLAs (Bilateral Embedded Licence exemptable Large power station Agreement) are treated identically within the transport model.

⁵ The zonal demand listed is from the final zonal demand used in the transport model 2008/9.

⁶ The total registered capacity is from the transport model 2008/9.

generation output for embedded exemptable large power stations at time of GB Transmission System peak demand. The DNOs have supplied the data and have recently requested National Grid to formalise arrangements for the submission of this data.

- 9.3 It is important in ensuring consistency, transparency and equality to all electricity market participants that the forecast generation output figure is utilised in the DCLF ICRP Transport Model for all embedded generators, less than 100MW in size, across the GB Transmission System.
- 9.4 It would be therefore inappropriate to utilise, within the transport model, a contractual capacity term allocated to the power station or a technical capacity term submitted by the affected generators as part of their annual Week 24 submission. The capacity information provided by or allocated to the affected generators is still applicable and necessary from a contractual, planning and operational perspective of managing the GB Transmission System.
- 9.5 It is acknowledged and accepted that the Week 24 data submitted by Users via the associated Grid Code obligations is used and disseminated for a variety of planning, operational and commercial purposes. It is therefore appropriate that the most relevant data item is selected for the circumstances in which it is going to be utilised.
- 9.6 The extra data would only be required from the Scottish DNOs as the proposal seeks to align the MW threshold between Scotland and England and Wales at 100MW. England and Wales DNOs will not have to submit extra data as all embedded generators are either modelled directly or included in current Week 24 submissions due to the definition of Large Power Station which applies in NGET's Transmission Area.
- 9.7 The Scottish DNOs are best placed to forecast the generation output as the metered output for existing stations is available when compiling the Week 24 demand data submission. For new stations, forecasting the connection date/output is an activity that is already being carried out for system planning purposes. In addition, the Distribution Code obliges embedded generators to provide forecast output figures to the DNO.
- 9.8 It is proposed that the manner of data provision is the same as for embedded small and medium power stations. The additional information would be captured through an extra item submitted via the current data process, ensuring minimal change to the existing data provisions and procedures and thus minimising the associated administrative burden.
- 9.9 Therefore the additional data request would form part of the existing Week 24 demand data submission, the provisions for which would be reflected in the Data Registration Code (DRC) Schedule 11 (Connection Point Data) with the associated data obligations specified with the Planning Code section of the Grid Code.
- 9.10 This proposal would ensure consistency of approach regarding the data utilised in the DCLF ICRP Transport Model; minimising the impact of regional variations associated to the Grid Code definition of Large Power Stations and equality in the way in which TNUoS charges are calculated for this classification and size of

power station. The utilisation of a capacity figure, within the transport model for embedded exemptable large power stations located in Scotland, would result in unacceptable disparities, lack of transparency and justification of the associated TNUoS charges. It is important that wherever possible a consistent approach should be utilised regarding the data used for a particular class of power station. Therefore the codification of the existing ad-hoc arrangements is appropriate and proportional to the requirement; ensuring greater transparency regarding the DCLF ICRP Transportation Model and equality to affected parties.

- 9.11 The proposed legal changes to the Planning Code and DRC are shown in Appendix A.

10. Impact on GB Transmission System

- 10.1 The proposed changes would not have any adverse impact on planning, maintenance and operation of the GB Transmission System.
- 10.2 The proposals will ensure equality regarding the treatment of power stations less than 100MW across the GB Transmission System thus ensuring consistency and transparency in the methodology utilised within the ICRP Transport Model.

11. Impact on Grid Code Users

- 11.1 The proposals will extend the existing, well established, Week 24 process for the capture of the forecast generation output for embedded exemptable large power stations thus minimising the associated administrative burden.
- 11.2 The proposal will codify current ad-hoc arrangements which have been in place since the implementation of BETTA between National Grid and the applicable DNOs. The proposals will provide additional User clarity and transparency regarding the data submission obligations.

12. Assessment Against Grid Code Objectives

- 12.1 The proposed changes outlined in E/08 Consultation document would better facilitate Grid Code Objectives:

ii) to facilitate competition in the generation and supply of electricity

by removing the inconsistencies in the way generation is modelled in the DCLF ICRP Transport Model by addressing and rectifying the impact of the regional differences in the definition of Large Power Station.

13. Impact on Industry Documents

13.1 *Impact on Core Industry Documents*

13.1.1 Grid Code Consultation E/08 (Grid Code Requirement for Forecast Generation Output for Embedded Exemptable Large Power Stations) has no impact upon other Industry Documents.

13.2 *Impact on other Industry Documents*

13.2.1 In the event that the proposal is not approved by the Authority, it may necessitate a formal review of NGET's Charging Methodologies Statement such that all generation less than 100MW is modelled (and subsequently charged) in a consistent and transparency manner.

C. RESPONSES

14. This section will contain a summary of responses received during the Consultation and will be completed as part of the Report to the Authority.

15. Views are invited upon the proposals outlined in this report. Especially views on the following areas would be welcomed:

- Impact of the proposals on Grid Code Users.

16. Your formal responses may be:-

Posted to: Lilian Macleod
Electricity Codes
Regulatory Frameworks
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

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Appendix A: Proposed Grid Code Changes

Planning Code Changes

PLANNING CODE

Insert new PC.A.4.3.6.

PC.A.4.3.6 Forecast generation output for the current **Financial Year** and the following seven **Financial Years** in respect of each **Embedded Exemptable Large Power Station** within the **User's System** on a **Grid Supply Point** basis are required at the time of peak **GB Transmission System Demand (Active Power)** as notified by **NGET** pursuant to PC.A.4.2.2.

Amend PC.A.4.4

PC.A.4.4 **NGET** will assemble and derive in a reasonable manner, the forecast information supplied to it under PC.A.4.2.1, PC.A.4.3.1, PC.A.4.3.4, and PC.A.4.3.5 and **PC.A.4.3.6** above into a cohesive forecast and will use this in preparing **Forecast Demand** information in the **Seven Year Statement** and for use in **NGET's Operational Planning**. If any **User** believes that the cohesive forecast **Demand** information in the **Seven Year Statement** does not reflect its assumptions on **Demand**, it should contact **NGET** to explain its concerns and may require **NGET**, on reasonable request, to discuss these forecasts. In the absence of such expressions, **NGET** will assume that **Users** concur with **NGET's** cohesive forecast.

Data Registration Code Changes

DRC Schedule 11

Amend DRC Schedule 11 to include forecast generation output data for embedded exemptable large power stations at system peak.

DATA REGISTRATION CODE

CONNECTION POINT DATA

SCHEDULE 11

The following information is required from each **Network Operator** and from each **Non-Embedded Customer**. The data should be provided in calendar week 24 each year (although **Network Operators** may delay the submission until calendar week 28).

Connection Point:

Connection Point Demand at the time of - (select each one in turn) (Provide data for each Access Period associated with the Connection Point)	a) maximum Demand b) peak GB Transmission System Demand (specified by NGET) c) minimum GB Transmission System Demand (specified by NGET) d) maximum Demand during Access Period e) specified by either NGET or a User
Name of Transmission Interface Circuit out of service during Access Period (if reqd).	PC.A.4.1.4.2

DATA DESCRIPTION (CUSC Contract <input type="checkbox"/> & CUSC Application Form <input type="checkbox"/>)	Outturn	Outturn Weather Corrected	F.Yr 1	F.Yr 2	F.Yr 3	F.Yr 4	F.Yr 5	F.Yr 6	F.Yr 7	F.Yr 8	DATA CAT
Date of a), b), c), d) or e) as denoted above.											PC.A.4.3.3
Time of a), b), c), d) or e) as denoted above.											PC.A.4.3.3
Connection Point Demand (MW)											PC.A.4.3.1
Connection Point Demand (MVA _r)											PC.A.4.3.1
Deduction made at Connection Point for Small Power Stations, Medium Power Stations and Customer Generating Plant (MW)											PC.A.4.3.2(a)
Reference to valid Single Line Diagram											PC.A.4.3.5
Reference to node and branch data.											PC.A.2.2

Note: The following data block can be repeated for each post fault network revision that may impact on the Transmission System.

Reference to post-fault revision of Single Line Diagram											PC.A.4.5
Reference to post-fault revision of the node and branch data associated with the Single Line Diagram											PC.A.4.5
Reference to the description of the actions and timescales involved in effecting the post-fault actions (e.g. auto-switching, manual, teleswitching, overload protection operation etc)											PC.A.4.5

Access Group:

Note: The following data block to be repeated for each **Connection Point** with the **Access Group**.

Name of associated Connection Point within the same Access Group :											PC.A.4.3.1
Demand at associated Connection Point (MW)											PC.A.4.3.1
Demand at associated Connection Point (MVA _r)											PC.A.4.3.1
Deduction made at associated Connection Point for Small Power Stations, Medium Power Stations and Customer Generating Plant (MW)											PC.A.4.3.2(a)
GSP:											
Forecast generation output of Large Exemptable Embedded Power Stations (MW) at the specified time of the annual peak half hour of GB Transmission System Demand											PC.A.4.3.6

Embedded Generation Data											
Connection Point:											
DATA DESCRIPTION	Outturn	Outturn Weather Corrected	F.Yr 1	F.Yr 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr 7	F.Yr 8	DATA CAT
Small Power Station, Medium Power Station and Customer Generation Summary	For each Connection Point where there are Embedded Small Power Stations, Medium Power Stations or Customer Generating Stations the following information is required:										
No. of Small Power Stations, Medium Power Stations or Customer Power Stations											PC.A.3.1.4(a)
Number of Generating Units within these stations											PC.A.3.1.4(a)
Summated Capacity of all these Generating Units											PC.A.3.1.4(a)

Where the Network Operator's System places a constraint on the capacity of an Embedded Large Power Station											
Station Name											PC.A.3.2.2(c)
Generating Unit											PC.A.3.2.2(c)
System Constrained Capacity											PC.A.3.2.2(c)

NOTES:

1. 'F.Yr.' means '**Financial Year**'. F.Yr. 1 refers to the current financial year.
2. All **Demand** data should be net of the output (as reasonably considered appropriate by the **User**) of all **Embedded Small Power Stations, Medium Power Stations** and **Customer Generating Plant**. Generation and / or Auxiliary demand of **Embedded Large Power Stations** should not be included in the demand data submitted by the **User**. **Users** should refer to the **PC** for a full definition of the **Demand** to be included.
3. Peak **Demand** should relate to each **Connection Point** individually and should give the maximum demand that in the **User's** opinion could reasonably be imposed on the **GB Transmission System**. **Users** may submit the **Demand** data at each node on the **Single Line Diagram** instead of at a **Connection Point** as long as the user reasonably believe such data relates to the peak (or minimum) at the **Connection Point**.

In deriving **Demand** any deduction made by the **User** (as detailed in note 2 above) to allow for **Embedded Small Power Stations, Medium Power Stations** and **Customer Generating Plant** is to be specifically stated as indicated on the Schedule.

4. **NGET** may at its discretion require details of any **Embedded Small Power Stations** or **Embedded Medium Power Stations** whose output can be expected to vary in a random manner (eg. wind power) or according to some other pattern (eg. tidal power)
5. Where more than 95% of the total **Demand** at a **Connection Point** is taken by synchronous motors, values of the **Power Factor** at maximum and minimum continuous excitation may be given instead. **Power Factor** data should allow for series reactive losses on the **User's System** but exclude reactive compensation network susceptance specified separately in Schedule 5.