# GUIDELINE NOTES
# FOR GENERATORS

## SUBMISSION OF GRID CODE DATA

**(Prepared by National Grid Electricity Transmission plc)**

**Issue 28**

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**Network Capability**
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## NOTES

These notes of guidance have been prepared by National Grid with the aim of assisting Users in completing the relevant Schedules of the Grid Code (GC). The guidance notes do not form part of the GC, and if there is any conflict between the Guidance Notes and the GC, or any other agreement, then that agreement shall take precedence.

## DOCUMENT CHANGE CONTROL DETAILS

| ISSUE No. | PUBLISHED | CHANGES MADE | APPROVED |
|---|---|---|---|
| Issue 22 | February 2001 | Page 5 (User System demand) text amplified. | P T Manning |
| Issue 23 | April 2001 | Page 16 Governor Time Constant explanation added.<br>Part II (Pages 19-23) : Amended to take account of NETA changes<br>Part IV (Fault Infeeds): additional clarification provided. | |
| Issue 24 | March 2004 | Revision to comply with Issue 2 – Rev.14 of the GC | D. Balasingam |
| Issue 25 | April 2006 | Update in accordance with Grid Code Issue 3 Revision 15 | K.F. Dan |
| Issue 26 | April 2007 | Updates to reflect data requirement for data relating to renewable generation. Contact details added. | K.F. Dan |
| Issue 27 | April 2008 | Updates to reflect the changes of data requirement for data relating to Power Park Module/Unit. | F. Xue |
| Issue 28 | March 2017 | Updates to changes of data requirement for Offshore Transmission Owners | S Boyle |

## INTRODUCTION

This note provides guidance on the completion of Schedules 1, 2, 4, 5 and 14 of the Data Registration Code (DRC). It is in six parts as follows:

- I Guidance notes on Schedule 1
- II Guidance notes on Schedule 2
- III Guidance notes on Schedule 4
- IV Guidance notes on User's System Data (Schedule 5)
- V Guidance notes on Fault Infeed Data (Schedule 14, previously Schedule 13)
- VI Guidance Notes on OFTO System Data (Schedule 18)
- VII Contact details

These guidance notes deal with Planning Data, i.e. data which a GB Transmission Operator will use for planning or the System Operator for operational planning. The data should therefore represent the expected position on a medium term basis. On the day variations to some data may be necessary, e.g.:

- minimum generation may be reduced during commissioning
- a short term MVAr limit may exist

These are dealt with separately under the Balancing & Settlement Code and Grid Code.

Where data is to be submitted in accordance with the annual week 24 process and no changes have been made to the required data whether required or previously submitted, a response to NGET by e-mail to this effect may be made in accordance with PC.4.3.1.

Proformas for providing this data are available to download from National Grid's Industry Information website in Word and PDF format:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/

Standard Planning Data and Detailed Planning Data are required for all existing and proposed generators (CUSC contract accepted with connection dates within the succeeding seven financial years) and all connected projects in Week 24 of each year.

Data Requirements for Power Stations

| | Size of Power Station | | | | |
|---|---|---|---|---|---|
| **Type of Connection** | **Small** | **Medium** | **Large** | Applicable paragraphs | Applicable DRC Schedules |
| **Direct** | Yes | Yes | Yes | PC.A.2.1.1 (PC.A.2.5.5) and PC.A.3.2 to 3.4 (not | 1, 2, 4, 5, 14. |
| **Embedded (Sub-transmission connected)** | PC.A.3.2.2( a) only (Registered Capacity) | Yes | Yes | PC.A.2.1.1 (PC.A.2.5.5) and PC.A.3.2 to 3.4 (not small) | 1, 2, 5, 14, (4 req'd for Large) |
| **Embedded (Not Sub-transmission connected)** | No* | No* | Yes | n/a | 1, 2, 4, 5, 14. |

* Yes when in relation to a CUSC contract or specifically requested by NGET.

Data shall be entered in the DRC schedule format, the attachment of subsidiary data thus being minimised.

Classification of Power Stations
The classification of power stations is dependent upon their location with respect to transmission system ownership as tabulated below.

| Class | NGET /MW | SPTL /MW | SHETL /MW |
|---|---|---|---|
| **Large** | ≥ 100 | ≥ 30 | ≥10 |
| **Medium** | 50 ≤ Pg ≤ 100 | | |
| **Small** | < 50 | < 30 | < 10 |

## 1. CHANGES IN REGISTERED CAPACITY

There are times when the registered Capacity of a plant is altered. The revised value should be provided as an amendment to Schedule 2. However, there are a number of other parameters which also depend on the Registered Capacity and these may also need to be amended. This may include:

- Performance Chart (Schedule 1)
- Run-up and run-down Rates (Schedule 2, Page 2).
- Governor Droop at Registered Capacity (Schedule 4).

It is unlikely that the data in Schedules 5 or 14 would be affected by a simple change in Registered Capacity.

# PART I
# GUIDANCE NOTES ON DATA REGISTRATION CODE SCHEDULE 1

Page references refer to pages within Schedule 1 of the DRC.

## 1. Generating Station Demands

There are three ways in which demands can be taken by a Power Station, namely:

- Unit transformers
- Station transformers
- From the Users System

Figure 1 shows typical examples of these three types.

## 2. Unit Transformers

Unit Transformers are typically used to supply station auxiliaries - typical voltage ratios are 23/11kV or 15/6.6kV. Demands taken by the Unit Transformers are not to be supplied on Page 1 of Schedule 1; they are included on Page 3 as 'normal auxiliary load'. Virtually all Power Stations have Unit Transformers.

## 3. Station Transformers

Station Transformers are an alternative direct connection to the Grid. They are used in most ex-CEGB coal plant, and in a few CCGT's. Typical voltage ratios are 400/11, 275/11 or 132/11. They are used for station start-up, and also sometimes supply a proportion of the auxiliary power.

Demand supplied through a station transformer is to be provided on Page 1 of Schedule 1.

## 4. User System Demand

User System Demand occurs when there is a considerable User System, usually at an intermediate voltage between the generator terminal voltage and the transmission voltage. Such arrangements generally occur when the Power Station is a 'Customer Generating Plant', i.e. providing electricity to an industrial plant or factory. The acid test is, 'can the electricity flow from generator to industrial plant without passing through another User's System (generally either part of the DNO system or even the GB Transmission System)?'. If the answer is ‘yes’ then it is User System Demand, and should be included on Page 1, Schedule 1.

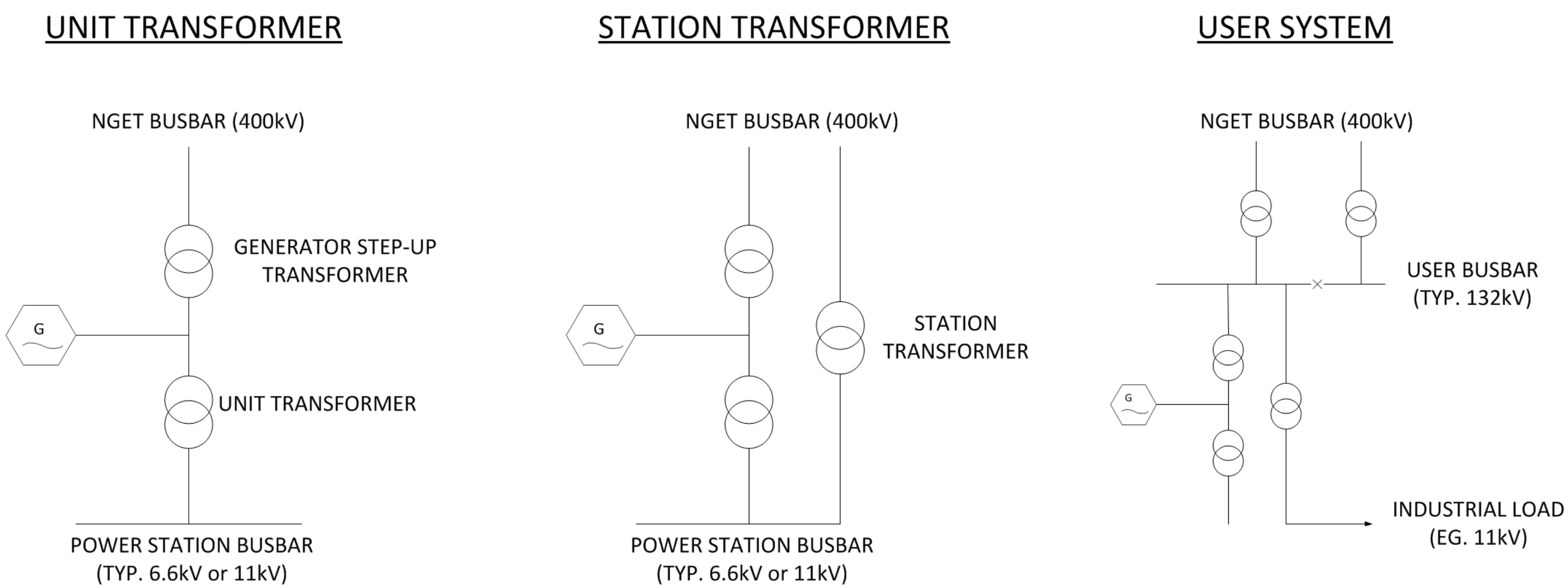
Station Transformer & User System Demands, provided on Page 1 of Schedule 1, are required at three points in time : at the GB Transmission System peak demand, at GB Transmission System minimum (the time and data of these is specified by NGET no later than week 17), and at local peak. In all cases the half-hour average demand is required.

The peak demand should represent the maximum demand that one might expect to occur in a year, not the maximum possible demand under extreme operating conditions. To be consistent with demands provided by other Users, there should be a 50% probability that the peak demand is exceeded in any one year.

## 5. Point of Connection to the GB Transmission System/User System

The substation name and voltage is sufficient for existing generating stations. The geographical and electrical location and busbar sections are only required for new applications. The point of connection to the User system shall be specified in the case of embedded generators.

# FIGURE 1


UNIT TRANSFORMER
NGET BUSBAR (400kV)
GENERATOR STEP-UP TRANSFORMER
G
UNIT TRANSFORMER
POWER STATION BUSBAR
(TYP. 6.6kV or 11kV)
STATION TRANSFORMER
NGET BUSBAR (400kV)
G
STATION TRANSFORMER
POWER STATION BUSBAR
(TYP. 6.6kV or 11kV)
USER SYSTEM
NGET BUSBAR (400kV)
USER BUSBAR
(TYP. 132kV)
G
INDUSTRIAL LOAD
(EG. 11kV)

## 6. Performance Chart (PC.A.3.2.2.f)

The charts should be constructed and drawn up in accordance with the instructions given in Operating Code No 2(OC2) in the GC, OC2 4.2.1 and Appendix 1 of OC2.

The performance chart should represent the capability of the combination of **prime mover**, and **generator**. This capability should be shown as MW/MVAr capability at the **generator terminals**. In addition the chart should show any constraints imposed by the Generator Transformer.

Figure 2 shows a chart for a notional generator. This chart is annotated to show what its various limits represent.

## 7. Temperature Effects

The chart in figure 2 gives a simple value of the limit for both the prime mover and the generator. Where either the prime mover output, or the generator capability varies significantly with temperature this chart is inadequate.

Figure 3 shows a performance chart with the effects of temperature added. This chart notionally represents a gas turbine plant whose output is temperature dependent. Curves are given for 4 values of ambient temperature.

Where the output of the generator is significantly dependent on temperature a chart in the form of Figure 3 should be submitted. The temperatures selected should cover a reasonable range of ambient temperature, and they should include:-

1) The ambient temperature at which the plant output equals the Registered Capacity

2) The ambient temperature which represents the rating of the prime mover (for CCGT's this would normally be 15$^0$C).

3) The ambient temperature that represents rating conditions for the generator (this will normally be in the range 25-35$^0$C such that the coolant inlet temperature to the generator is 40$^0$C, as per IEC 34-3).

Please note that, for CCGT's, separate charts are likely to be applicable for the gas and steam turbines *even if the generators are identical*, because the prime mover output will show different variations with temperature.

Where capacity of a generator transformer varies with temperature in such a way as to constrain the generator output (MW or MVA) under certain ambient conditions, this should be notified.

FIGURE 2 – NOTIONAL PERFORMANCE CHART

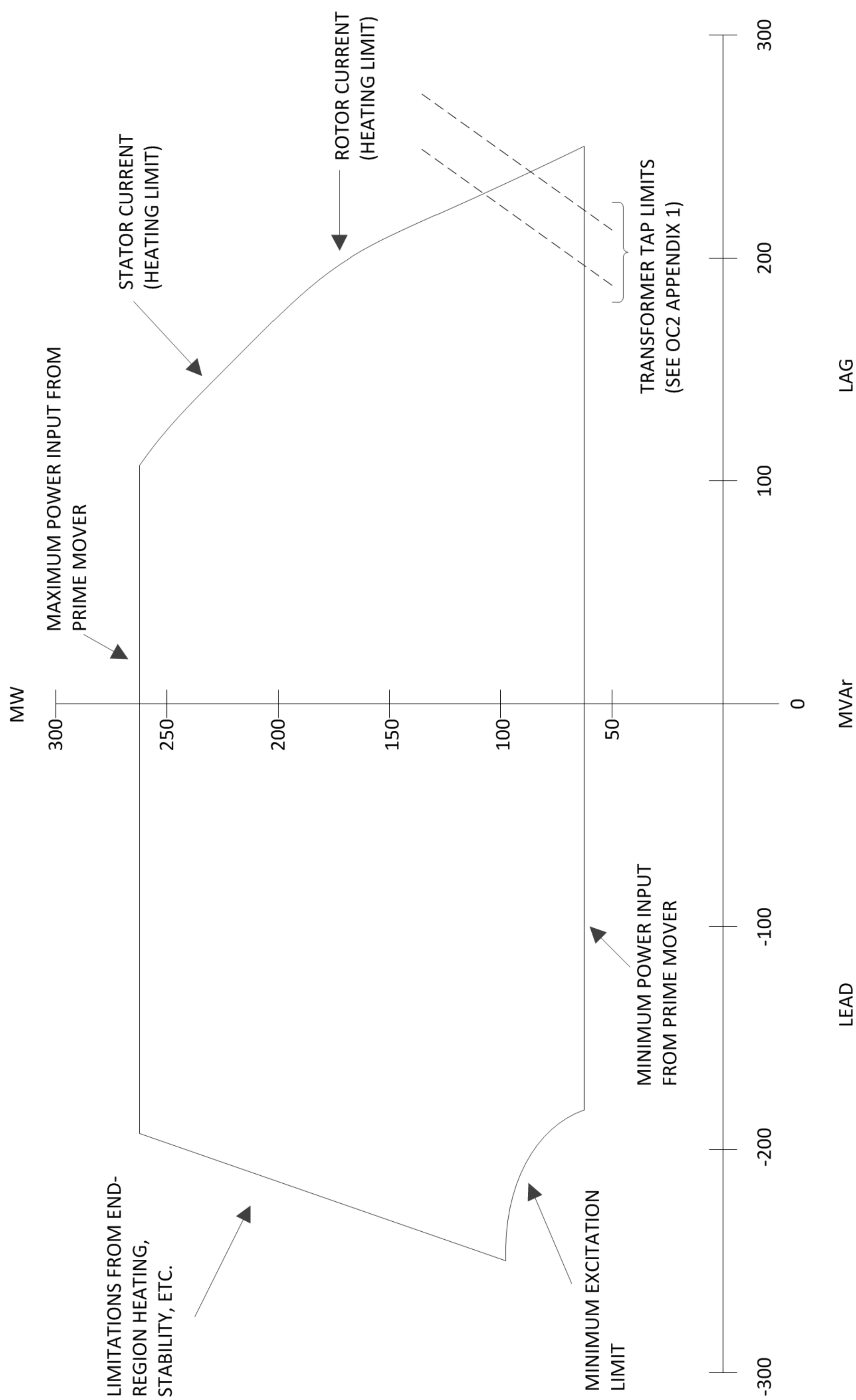
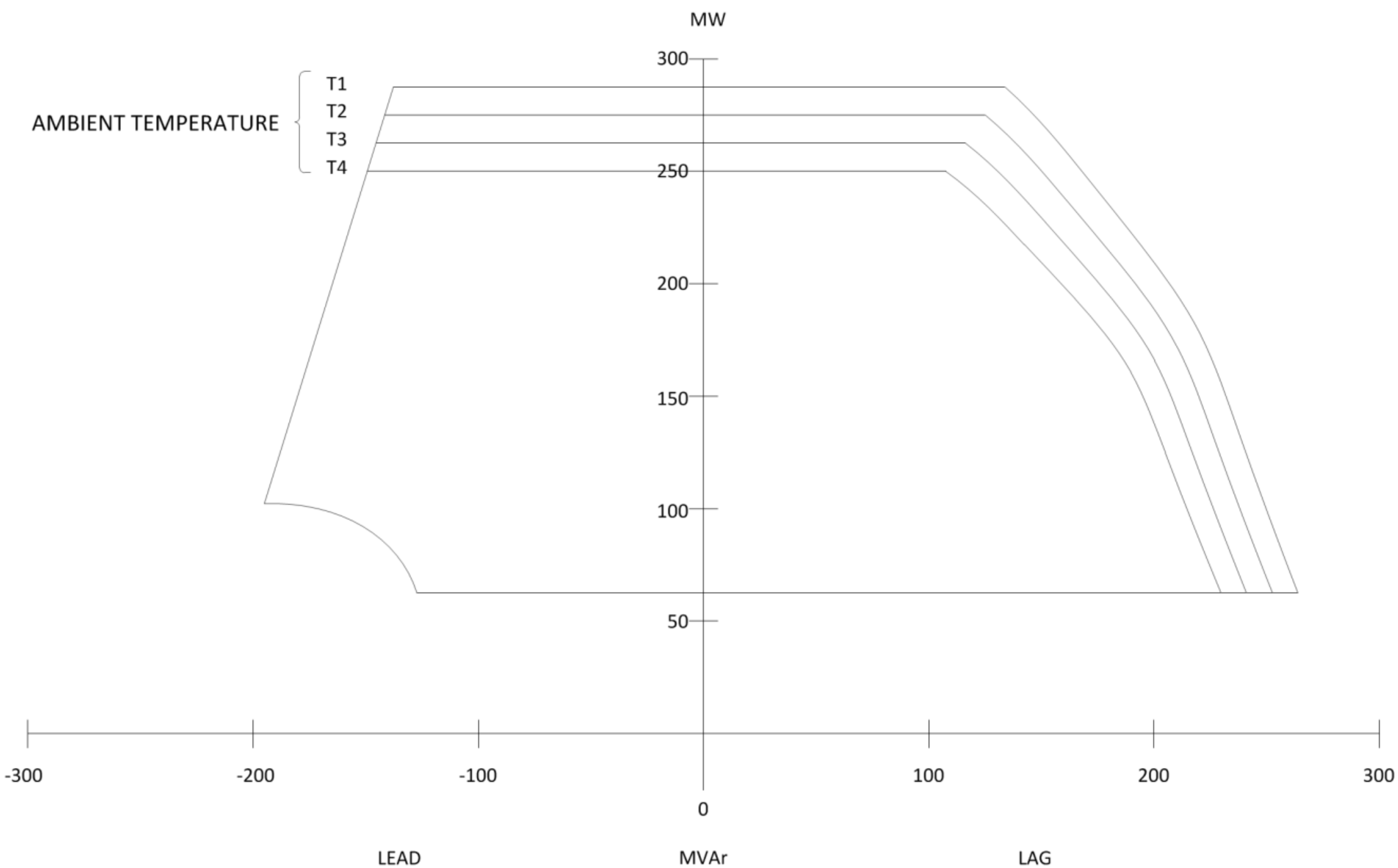


FIGURE 3


MW
300
250
200
150
100
50
AMBIENT TEMPERATURE
T1
T2
T3
T4
-300
-200
-100
0
100
200
300
LEAD
MVAr
LAG

## 8. Minimum Generation

Figures 2 and 3 show a horizontal line representing the unit's minimum generation. For modular CCGT's this is not the Minimum Generation as defined in The GC (as this is a modular concept) but will nevertheless represent some plant limit encapsulated in the modular Minimum Generation.

For example, consider a 750MW CCGT made up of 2 x 250MW GT's, 1 x 250 ST. Emission limitations prevent extended running of a GT on open cycle and the practical minimum combined cycle generation is 150MW (gas turbine at 60% load) + 75MW (steam turbine). At loads up to 375MW the plant runs on 1GT + 1ST; above 375MW the second GT is started up.

This would then be represented as follows:

| | |
|---|---|
| Modular Minimum Generation | 225MW |
| **GT Minimum Generation on Performance Chart** | **150MW** |
| ST Minimum Generation on Performance Chart | 75MW |

## 9. Inertia Constant

The Inertia Constant should represent the inertia of the entire power train (turbines and generator), and not simply that of the generator alone.

## 10. Short-circuit ratio (PC.A.3.3.1(b) and PC.A.5.3.2(a))

The short circuit-ratio is conventionally defined as:

$$\frac{\text{open circuit field current to obtain 1p.u. terminal volts}}{\text{short-circuit field current to obtain 1p.u, terminal current}}$$

The value of 1 p.u. terminal volts is well defined as the rated terminal voltage. The value of 1 p.u. terminal current is less well defined, as generator ratings are typically temperature dependent. As IEC recommend that a temperature of 40$^o$C is used for rating generators, it is suggested that this temperature is used for calculating the short-circuit ratio.

## 11. Impedances (PC.A.3.3.1(a), (b), (c), (e) and PC.A.5.3.2.a)

The impedance values should all be <u>unsaturated</u> values, conventionally defined as measured at 50% rated terminal volts.

The Armature Winding Direct Current Resistance is defined in clause 15 of IEC 34-4. The requirement to provide this data item came into force on 1st March 1996. For plant commissioned prior to that date, the data only needs to be supplied if the Generator is aware of the value.

To convert the Armature Winding Direct Current Resistance from ohms/phase to percent on the machine rating, you can use the following equation:

$$R\% = R \times (MVA_{rating)} \times 100/(kV)^2$$

where R = Armature Winding Direct Current Resistance in ohms/phase
$MVA_{rating}$ = Rated MVA
kV = Rated Terminal Voltage

## 12. Time Constants (PC.A.5.3.2(a))

Please provide the time constants under short-circuit conditions, and confirm definitively that this has been done. Three phase values only are required.

## 13. Generator Transformers

The GC, as written, assumes that all transformers are of the 2 winding type (although a tertiary winding is catered for). If the transformer has 3 windings, i.e. two secondary windings, please see Part IV, Section3 for information on how that data should be provided.

## 14. Transformer Ratios (PC.A.5.3.2.(b))

Please express transformer voltage ratio as a ratio (e.g. 400/11) rather than as a quotient (e.g. 36.36).

## 15. Maximum and Minimum Taps (PC.A.5.3.2.(b))

Minimum tap number corresponds to the highest number of turns on the HV winding i.e. highest plus percent position or highest p.u. tap ratio. This corresponds to the highest HV/LV voltage ratio and so highest HV voltage for a fixed LV voltage. Conversely, it would correspond to the lowest LV voltage for a fixed HV voltage.

## 16. Zero Phase Sequence Reactance

Part V explains the calculation of zero sequence reactance for a "star-star" transformer.

Generator transformers are normally in a "star-delta" configuration, without a tertiary, and the zero sequence impedance to neutral of the "delta" winding is infinite. This simplifies the issue because only one sensible measurement can be made, the zero sequence impedance from the "star" windings (i.e. ZOH-T//N or ZOL-T//N, depending on whether the "star" winding is hv or lv).

## 17. Excitation

From revision 12, the GC included a major revision of the excitation system data that should be provided to NGET. Generators should supply data on all new plant in the new format. For existing plant generators may rely on the existing formats unless:

a) They have knowledge of the data in the new format
b) The system is modified.

A detailed block diagram of the excitation system should be provided. These should allow NGET to model accurately the behaviour of the Generating Unit in power system stability studies.

The data provided for modelling the excitation system should generally be in accordance with IEC 34-16 'Excitation systems for synchronous machines' or the equivalent BS 4999: Section 116.

This diagram should be a mathematical model of the excitation system, including main and pilot exciters if present, for power system stability studies and should adequately represent the actual excitation system performance during steady state and dynamic conditions, as detailed in IEC 34-16-2. The model parameters should preferably be in the per unit system described in Appendix A of the above document.

**Dynamic characteristics of over/under-excitation limiters:**

Information in block diagram form should be provided about the implementation of over/under excitation limiters within the control system.

## 18. Governor Parameters (PC.A.5.3.2.d)

Revision 12 of the GC contained a major alternation to the requirements for data on Governors. Generators should provide data on all new plants in the new format. For existing plant Generators may rely on the existing formats unless:

a) They have knowledge of the data to the new format, or
b) The governor is modified.

The information required is to enable NGET to model the behaviour of all dynamic plant over all transient time scales that are of interest in being able to run a stable system that complies with NGET's licence standards. The effects that occur over different time scales may require different sophistication of models.

## 19. Speeder Motor Setting Range

The term 'Speeder Motor' is an old-fashioned term referring to mechanical governors. The 'Speeder Motor' is a device to adjust the mechanical characteristics of the Governor to alter the target speed. Typical values of the 'Speeder Motor Setting Range' are 95% - 105%, i.e. the unit could be set to a target frequency of 50Hz + 5%.

Although Modern electronic governors do not have a speeder motor as such, nevertheless the concept is still valid: information should be provided on the possible range of target frequencies that can be put into the Governor. This should be expressed as a percentage of nominal frequency, e.g. 90%-110%.

## 20. Governor Average Gain

Governor Average Gain is defined as:

Governor Average Gain (MW / Hz ) = P / $\Delta f$

Where P = Generating Unit Rated Output (MW)
and $\Delta f$ = the change in frequency (Hz) corresponding to a generator output change from Rated Output to zero power output.

Rated Output is defined in IEC 34-1 / 34-3.

This figure should normally equate to an average droop of 4% on rating (or whatever is the normal value of the droop).

In the case of CCGT plant the Rated Output of the module is the sum of the rated outputs of all Generating Units which make up the module and the governor average gain would normally be equivalent to an average module droop of 4% on module rating. This will require Gas Turbine generator droop is set to a lower value to compensate for the Steam Turbine response should the Steam Turbine be operated in sliding pressure mode.

## 21. Governor Valve Opening Limits (PC.A.5.3.2.d)

Upper and lower position limits for HP (and IP and LP where applicable) throttle valve, in %.

## 22. Governor Valve Rate Limits (PC.A.5.3.2.d)

Opening and closing rate limits of HP (and IP and LP where applicable) throttle valve in % per second. These rate limits should include all rate limits, whether electronic or mechanical.

## 23. Governor Block Diagram (PC.A.5.3.2.d)

The User should provide sufficient information to enable NGET to accurately model the dynamic behaviour of each generating unit. A transfer function block diagram should be provided which demonstrates plant behaviour over the timescale 0-60sec.

The block diagram should provide details relating to at least the following aspects:

1) Governor configuration.

2) Fuel control details (where fuel is steam in fossil fuel fired plant, gas/oil in gas turbine plant and water in hydro plant). For example, actuator time constant, all valve opening and rate limits and time constants, exhaust temperature limits, boiler time constant.

3) Turbine response details. For example, in the case of steam turbines, HP, IP, LP time constant and power fraction, and for gas turbines, combustion effects, and for hydro plant, water time constant.

4) Acceleration sensitive details.

It should be noted that this is not considered an exhaustive list.

It is extremely important that for any block diagram supplied the units and associated base be explicitly identified. If the model is applicable for longer than the 0-60sec requirement, the timescale over which the model is accurate should also be stated.

Two internationally recognised references, which could be used when supplying the block diagrams, are:

(i) "Dynamic Models for Steam and Hydro Turbines in Power System Studies" - presented at the IEEE in New York in 1973.

(ii) "Simplified Mathematical Representations of Heavy Duty Gas Turbines" by W I Rowen - presented at the 28th International Gas Turbine Conference and Exhibition, Phoenix Arizona 1983. Paper No: ASME 83-GT-63.

In the case of CCGT plant, a model showing the interactions between gas and steam sides and associated control equipment should be provided. Such models should indicate, for example, the effects of heat recovery steam boilers, i.e. boiler time constant, process steam take-off and gas pipeline effects, where they are appropriate to the timescale under consideration.

## 24. Governor Time Constant

The Governor Time Constant should represent the time from signal acquisition (i.e. a change in frequency) to an instruction being sent to the relevant valve. It should not include the time constant of the valve itself, which is provided separately (Schedule 1 Page 8).

## 25. HP and IP Power Fractions

These should represent the fraction of the total steam turbine output provided by the HP and IP stages. For a single shaft machine, it is NOT the fraction of the total output (i.e. GT and ST).

## 26. Waste Heat Recovery Boiler Time Constant

This is identical to the 'boiler time constant' also on Page 7.

## 27. Unit Control Options

Droop under this section is defined as the average droop from Rated Output to zero generation and is calculated as follows:

Droop (%) = $(\Delta f / f_o)$ x 100%

Where $\Delta f$ = the change in frequency (Hz) corresponding to a generator output change from Rated Output to zero power output.

And $f_o$ = 50 Hz

## 28. Sustained Response Normally Selected

When the system frequency falls and is sustained below the target frequency setting of a part-loaded generating plant, its output is expected to rise and settle at an increased level. The amount of increase (above the generator Instructed Load) is dependent upon the amount of frequency deviation, the unit controller droop setting and the available steam valve headroom. Whether the output is to be sustained is governed by the unit controller 'Sustained Response' selector ON/OFF settings.

If 'ON' is selected, the output of the generator will be sustained as long as the frequency is depressed. However, if 'OFF' is selected, the output power despite the depressed frequency will be reduced to its instructed level by the unit controller action.

The above applies equally to system high frequency conditions (i.e. above Target Frequency). For instance, the unit controller on 'Sustained Response' mode will keep its generator output power to below the Instructed Load under a high frequency condition.

For a plant which is instructed to be frequency sensitive, its unit controller should be selected to the 'Sustained Response' mode to ensure the generator output is regulated to help the system frequency to return to its target level. The exception is that the plant is providing only 'Primary Response'.

## 29. Tolerances and Accuracy

Some parameters may be difficult to measure, or may depend upon other factors either internal or external to the power station (e.g. number of mills in service, or ambient temperature). In such cases the following principles apply:

1) Where the value of a parameter is given elsewhere in another agreement then the two values should be identical (e.g. Registered Capacity).

2) The values of parameters submitted under the GC should normally represent a central or most likely estimate - i.e. they should not represent a minimum or maximum value unless the context so requires.

3) The accuracy of data should follow ICE 34-3 Part 3, and in particular reactance should be "bona fide rated values, subject to a tolerance of _+ 15%" (Paragraph 16.3).

## 30. Governor Droop Characteristics (CC 6.3.7(c)iii)

Droop under this section is defined as the incremental droop at the loading point concerned, and is calculated as follows:

Droop (%) = [ ( $\Delta f / f_o$ ) x 100% ] / ( $\Delta P / P$ )

Where $\Delta f$ = a small change in frequency (Hz) and $f_o$ = 50 Hz

and $\Delta P$ = the corresponding change in power output (MW) at the given loading point

and $P$ = Generating Unit Rated Output (MW)

The droop should be provided after the initial transient. For CCGT's operating in sliding pressure mode, this effectively means after the gas turbine has responded, but before the steam turbine can respond.

The provision of Droop Data was amended by Revision 29 in January 2000. This amendment required the droop to be provided at the same levels of generation used in the provision of Response Data (see Page 15 and 16 of these Guidance Notes, and also Page 9 of the Data Registration Code, Schedule 1), namely MLP1 ("the Designed Minimum Operating Level); MLP2 ("the Minimum Generation); 70%, 80%, 95% and 100% of Registered Capacity. For Generating Plant under Construction, it is mandatory to utilise these load levels; for operating plant NGET prefers that these load levels are used, but this is not mandatory.

Please note the comment on Part III., of these notes about the values of MLP1 and MLP2.

## 31. Performance Chart (Power Park Module) (CC 6.3.2(c) and PC.A.3.2.2(f))

The chart should be constructed and drawn up in accordance with the instructions given in Operating Code No 2(OC2) in the GC, OC2 4.2.1 and Appendix 1 of OC2.

Capability should be shown as MW/MVAr capability at the **connection point or at the entry point into the User's system if embedded**.

## 32. Validated Mathematical Model (Power Park Unit/Module) (PC.A.5.4.2(a))

The User should provide sufficient information to enable NGET to accurately model the dynamic behaviour of each generating unit. A transfer function block diagram should therefore be provided which demonstrates plant behaviour over the timescale 0-60sec.

## 33. Power Park Unit Parameters (PC.A.5.4.2(b) to (h))

The User shall provide values in the requested units. Where, in the case of future projects specific manufacturer's data is not available, generic estimated values may be submitted on the proviso that these shall be subsequently replaced by specific values.

Quiescent electrical demand shall be provided for the zero wind condition.

The provision of Power Park Unit Data was amended in April 2008. This Amendment requires the following additional data:

(i) The user shall provide the air density parameters for the requested units. Air density varies according to elevation, temperature and weather fronts. The unit of air density is in kilograms per cubic meter. These parameters are used to calculate the amount of kinetic power transferred to a wind turbine and include the minimum, maximum and average values for the year.

(ii) The user shall also provide the detailed parameters of a two mass model of the drive train. This shall contain the equivalent inertia constant of the first and second mass at minimum, synchronous and rated speed and the equivalent shaft stiffness between them. The first mass represents the equivalent turbine and blades inertia and the second one is equivalent to the generator inertia. In stability analysis, when the system response to large disturbances is analysed, a detailed multi-mass shaft model is required for all types of wind generators.

The description of the power electronic converter included with the transfer function block diagram should include fault ride through capability where applicable.

## 34. DC Converter Station Parameters (PC.A.5.4.3)

The User shall provide values in the requested units. Where, in the case of future projects specific manufacturer's data is not available, generic estimated values may be submitted on the proviso that these shall be subsequently replaced by specific values.

# PART II
# GUIDANCE NOTES ON DATA REGISTRATION CODE SCHEDULE 2

The following notes are to read in conjunction with DRC Schedule 2.

## 1. Minimum Generation (PC.A.3.2.2.d and PC.A.5.3.2.a)

This should be the minimum continuous generation when running on the main fuel and should be provided on a modular basis. It should be emphasised that the value given is a planning value and can be altered in the Generator's daily FPN or Offers and Bids to the Balancing Mechanism.

Please see comment in Section 18 later in this Part about a possible 'forbidden zone' in a multi-shaft CCGT.

It is accepted that each unit (and the module) will be generating at less than "minimum generation" for some period during start-up/shut-down.

## 2. CCGT Modules

For CCGT Modules the data in Schedule 2 should be provided on a modular basis rather than a unit basis.

## 3. General

These parameters are required to allow NGET to evaluate possible dynamic problems associated with changing generation output. In general, generating plant cannot instantaneously adjust its output, and the limitations are most restrictive when the plant is cold - hence values assuming cold plant should be provided. Values provided under Schedule 2 will not be used for real-time operation.

## 4. The Run-up Rate Model

Figure 4 gives an example of the possible loading for a unit. Following an instruction to synchronise, it takes a period of time (the Notice to Synchronise) before the unit can be synchronised with power output equal to the synchronising generation. The plant output will then run up linearly to output level MWL1 at a rate of RUR1 MW/min; then to output level MWL2 at a rate of RUR2 MW/min and to the Registered Capacity at RUR3 MW/min.

Run up and run down rate shall also be given for Large Power Parks with respect to each Power Park Module. (PC.A.5.3.2(f))

## 5. Regime Unavailability (OC2.A.2.1)

If there are fixed times (e.g. determined by shift patterns) for earliest synchronising or latest de-synchronizing these should be given. Please note this does not refer to the predicted amount of actual running. If the plant is expected to be fully available 24 hours/day, 7 days/week then N/A can be given.

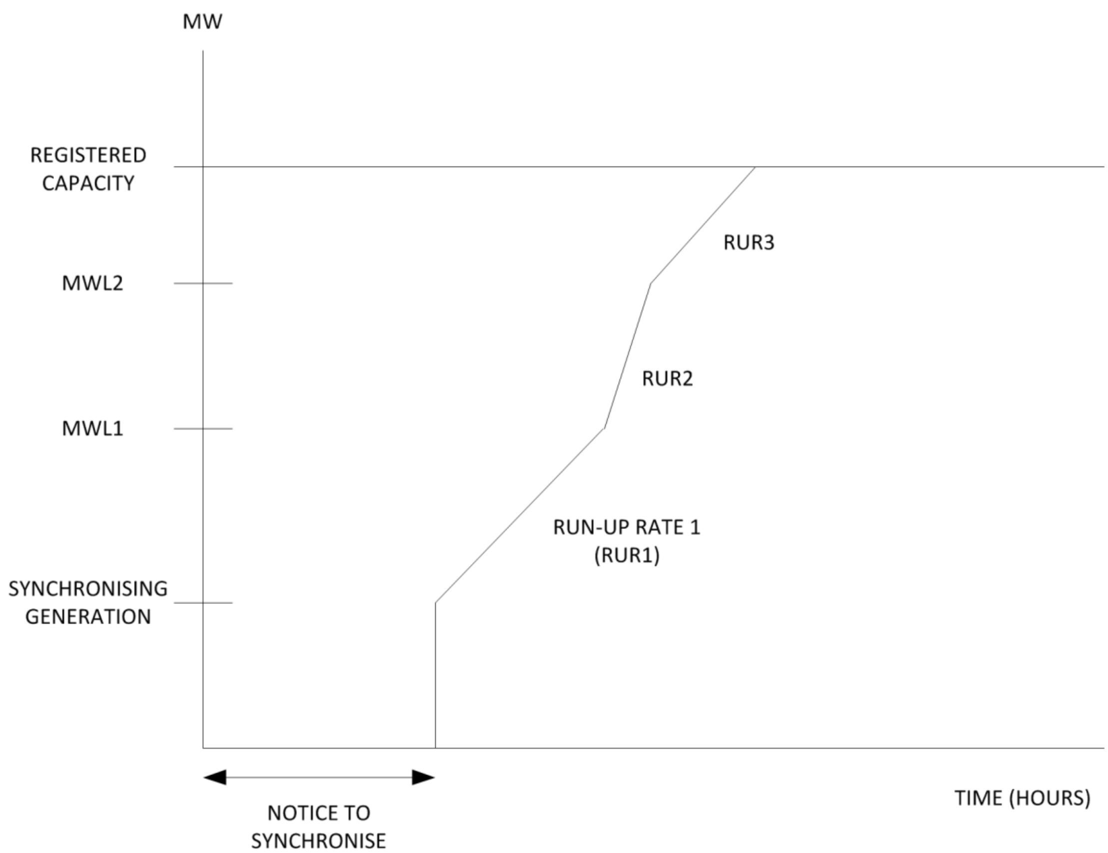
## 6. Expected Running Regime (PC.A.3.2.2.h)

Licence Standard P2/5 requires NGET to determine the contribution that generation makes to security according to its running regime, and P2/5 divides plants into base load; day-plateau and peaking plant according to the station staffing regime.

A station fully manned (or completely automatic) is classified as base load; one manned for only two shifts is day-plateau and one manned for only a single shift is peaking plant.

Generators are therefore asked to indicate what staffing regime is expected so that NGET can apply Licence Standard P2/5 if necessary. The information should ideally by supplied with respect to the shift pattern for which the station is manned (7d 3s representing seven day three shift operation, i.e. twenty four hours a day, seven days per week) but a return as "base-load", "day-plateau" or "peaking" plant is acceptable.

FIGURE 4 – RUN UP CURVE




It should be emphasised that NGET is looking for a statement of capability, not a prediction of how the station will actually run. How the plant will actually run will be governed by commercial issues. What is of interest to NGET are cases when external constraints mean that the power station cannot run.

## 7. Notice to Deviate from Zero (NDZ)

This means the necessary elapsed time between NGET informing a Generator that a Generating Unit is required to synchronise and synchronisation being achieved.

## 8. Station Synchronising Intervals (OC2.A.2.2)

The synchronising interval is the time that will elapse, following synchronising of one unit, before the next unit can be synchronised. If the Generating Units in a station are allocated to one Group only the same interval will apply between any two Generating Units, but it will be recalculated according to the state of warmth of each Generating Unit and this recalculated interval will be applied between that Generating Unit and the one that precedes it in the synchronising order. The synchronising order is decided on the basis that the Generating Unit with the longest load-up time from synchronising to full load will be synchronised first and so on. If the facility to split the station into Groups is applied each Group will be treated independently of the others using the same logic as discussed above (See Note 1 on DRC

Schedule 2, Page 3). It is up to the User to decide whether to use the facility to split the station into Groups bearing in mind the general comments above relating to accuracy and approximations. This data item is not applicable to a Generating Station containing a single CCGT module.

## 9. Synchronising Generation (OC2.A.2.4)

The value being sought here is not a value at the precise moment of synchronising or at some fixed interval thereafter. It is assumed that the loading rate to the first MW breakpoint (MWL1 - see 4 above) applies from the instant of synchronising. The registered Synchronising Generation should therefore be chosen in conjunction with the first MW loading rate such that the correct time to achieve MWL1 results.

## 10. Minimum non-Zero Time (OC2.A.2.5)

This refers to the minimum time that a Generating Unit must remain synchronised following a shutdown period.

## 11. Minimum Zero Time (OC2.A.2.9)

This is the minimum period for which a Generating Unit must remain de-synchronised if it is taken off-load.

## 12. Two-Shifting Limit (OC2.A.2.10)

This is the maximum number of times that a Generating Unit may be required to two shift, i.e. desynchronise and re-synchronise again. A zero entered here will identify the Generating Unit cannot be two shifted. It does not imply the Generating Unit may not be required to shutdown for a period greater 24 hours.

## 13. Run-up Rates (OC2.A.2.6)

The assumption is made that the run-up curve can be represented by 3 run-up rates. If in practice this is not the case then the real data must be approximated. Similarly if there are more than three loading rates following synchronising to achieve Registered Capacity these must be approximated to three rates which best fit the true loading characteristic.

## 14. Run-down Rates (OC2.A.2.7)

The run-down rates quoted should assume that the plant has run at its Registered Capacity for an indefinite length of time so that it has reached equilibrium.

## 15. Regulating Range (PC.A.5.3.2.f)

This has been moved from Schedule 1 (Revision 26). It should represent the range over which the plant can operate under full automatic control. It should be assumed that all auxiliary equipment is available and the plant is operating at design conditions.

## 16. Load Rejection Capability (PC.A.5.3.2.f)

This has been moved from Schedule 1 (Revision 26). This is the maximum load that can be rejected when operating at full load and design conditions without the unit losing synchronism or tripping. It is not intended that the plant is ever asked to undertake full load rejection; rather the data is required for "disaster planning".

## 17. Range Station

Generating Units at range stations should normally be modelled as if the boiler backing can be arranged such that there is no limitation imposed upon the turbo-alternator performance.

If boiler considerations do impose limitations then the registered parameters should represent the combined capability. Where different combinations of boilers and turbines would give rise to different parameters the most likely situation should be used as the basis for preparing parameters.

## 18. CCGT Module Matrix

For CCGT Modules, a CCGT Module Matrix, showing which units will generate if the module is scheduled at part load, should be provided. An example is given in OC2 Appendix 3.

The CCGT Module Matrix is only applicable to CCGT's and should represent the most likely configuration if the CCGT is scheduled at part-load for an indefinite period. It is not applicable to single-shaft units (i.e. where gas turbine, steam turbine and generator are on a single shaft).

Although not shown in the example in OC2 Appendix 3, it is possible for a CCGT module to have a 'forbidden zone', e.g. a 750MW CCGT made up of 2 GT's and 1 ST might be able to operate comfortably indefinitely between 225MW and 375MW with a 1 + 1 configuration, and between 450MW and 750MW with a 2 + 1 configuration, but there is no operating regime to give an output between 375 and 450MW. If this is the case it should be shown in the Matrix (see example below).

The example above (also given on pages 7-10) would have the following CCGT Module Matrix:

| MW | GT1 | GT2 | ST |
|---|---|---|---|
| 225 - 375 | X | - | X |
| 375 - 450 | No practical running arrangement | | |
| 450 - 750 | X | X | X |

# PART III

## GUIDANCE NOTES ON DROOP AND RESPONSE (Schedule 4)

### Response Capability

The Designed Minimum Operating Level is that output below which the Dispatch Unit has no high frequency response capability, i.e. if the frequency increases the load will not fall. This value can be differentiated from the Minimum Generation (see Schedule 2) which is the minimum level at which the Generator is willing to let the plant be Scheduled, and is generally (but not always) higher than the Designed Minimum Operating Level. Examples of why the Minimum Generation may be above the Designed Minimum Operating Level may be if there is an emissions restriction (e.g. $NO_x$ output) which affects the level at which the plant may be Scheduled.

Primary and Secondary Response are defined in the GC: Primary Response is measured over timescales of 10-30 seconds, and Secondary of 30 seconds - 30 minutes after a 0.5Hz ramp downwards over the period 0-10 seconds. (Previous versions of the Code refer to a step, and were incorrect). High frequency response is that response available 10 seconds after the start of an upward frequency ramp, and available indefinitely.

For multi-shaft CCGT (e.g. a module with 2 GTs and 1 ST) there is an element of ambiguity. The definitions of Minimum Generation, and Designed Minimum operating Level, refer to a modular output level, and would generally represent the output with only one gas turbine (and the ST) synchronised. The values that NGET are seeking, however, are values with **all** units synchronised. Hence the value of MLP1 on Schedule 4 should represent 'the level at which no high-frequency response capability is available but with all units synchronised', and similarly MLP2 will be 'the minimum value at which the generator is prepared to operate the module indefinitely assuming all units are synchronised'. It is generally assumed that all GTs in a module will be equally loaded, assuming that they are identical, and that they share the response capability equally.

The values of response are to be provided at 6 output levels, the Designed Minimum Operating Level, Minimum Generation, 70%, 80%, 95% and 100% of Registered Capacity. For plant under construction the above levels are mandatory; for operational plant the levels are preferred by NGET, but are not mandatory.

# PART IV
# GUIDANCE NOTES ON USER SYSTEM DATA (Schedule 5)

Schedule 5 deals with User System Data. Although the data here primarily applies to DNOs (which have large User Systems) some data is also applicable to Generators.

Revision 28 of the GC (November 1999) made major changes to Schedule 5. Although these changes largely affect Distribution Network Owners, there are some spin-off changes which affect Generators, fully detailed below.

## 1. Definitions

A User System contains all electrical plant and apparatus at all voltage levels. The GC divides it into three parts:

(i) User's Supergrid Higher Voltage System (PC.A.2.2.2)

Equipment operating above 200kV directly connected to the GB TRANSMISSION SYSTEM (in practice this is all equipment operating at 275 or 400 kV).

(ii) User's Subtransmission Primary Voltage System (PC.A.2.2.2)

This comprises all equipment operating at the next transformation level down from supergrid voltage.

(iii) The Remainder of the User System

This comprises all other equipment; limited data may be required depending on type of use.

Figure 5(a) and (b) shows two typical power station layouts, showing the User System divided into these three parts. Figure 5(a) has the station transformers connected at 275kV (or 400 kV), figure 5(b) has them connected at 132 kV or lower.

Figure 5(c) shows the Single Line Diagram for a Power Park Module which contains the Equivalent Network. The Equivalent Power Park Units shall represent all of the actual Power Park Units in the Power Park Module. The Common Collection Busbar in a Power Park Module is defined as a busbar to which the higher voltage side of two or more Power Park Unit generator transformers are connected.

## 2. Data Requirements

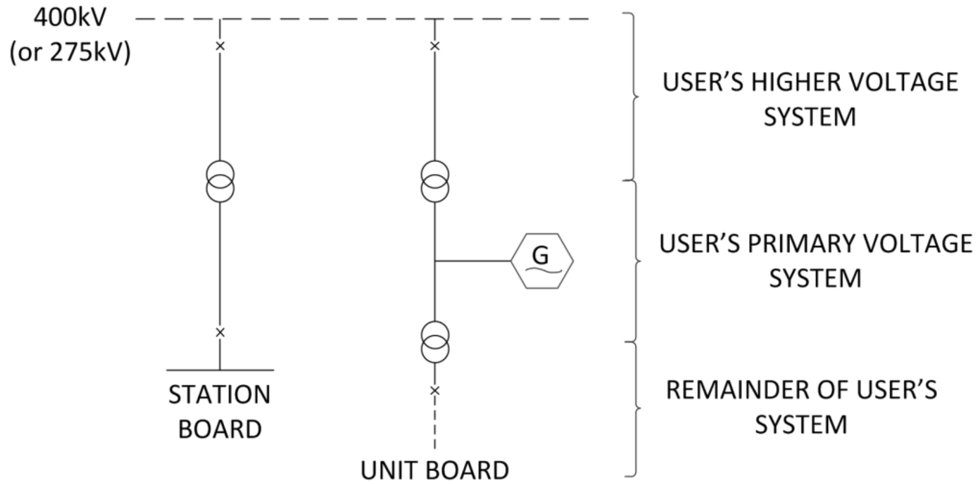
Requirements for User's system data are given in section PC.A.2 of the GC. The summary below considers each section in turn. In many cases reference is made to 'typical connections' which should be taken as applying to Power Stations with connections as shown in Figure 5 (a) or (b).

### Single Line Diagram (PC.A.2.2.1)

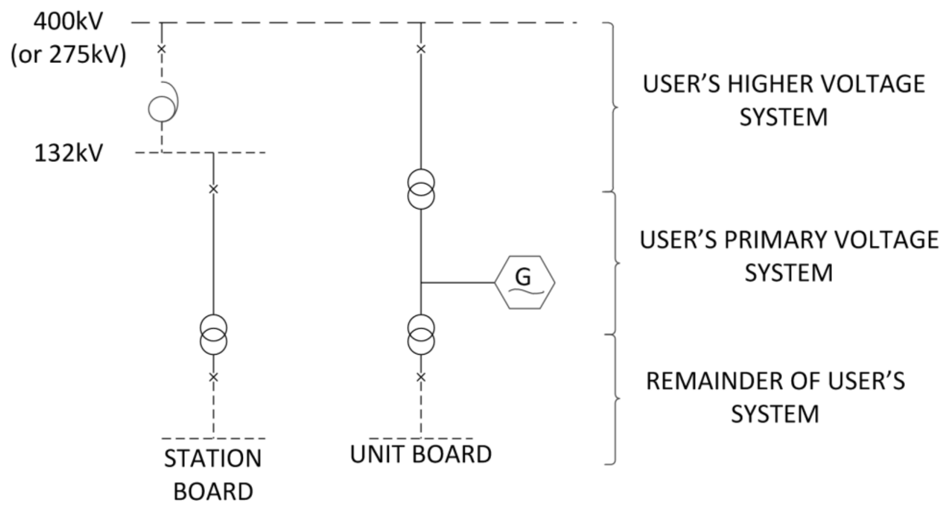
Generators are asked to provide a Single Line Diagram showing the layout of their system. The level of detail required is that shown in Figures 5(a) and 5(b). Note that phasing arrangements for overhead conductors operating at 400kV or 275kV is required.

The Single Line Diagram is not the Operations Diagram referred to in the Connection Conditions, although in some cases the Operations Diagram can be used as a surrogate for the Single Line Diagram.

## FIGURE 5(a) – Generator and Station Transformer Connected to Supergrid




## FIGURE 5(b) – Generator Connected to Supergrid and Station Transformer Connected at 132kV



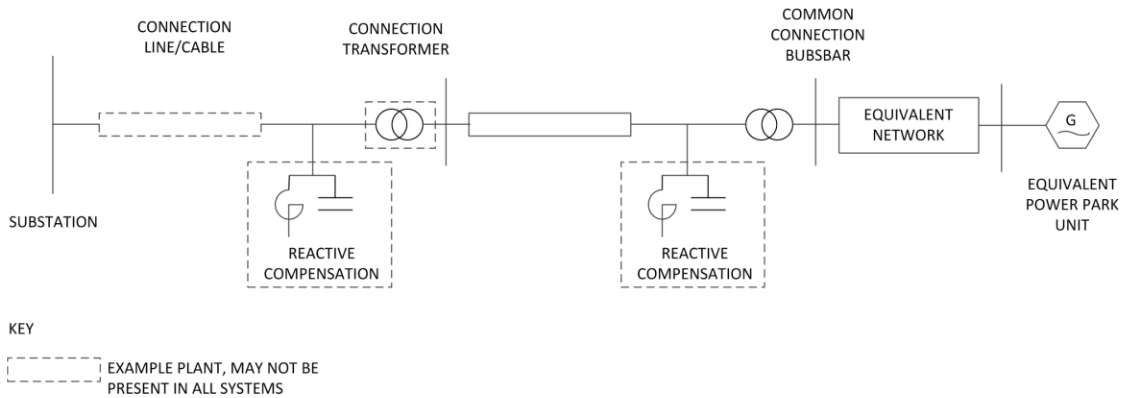

KEY

PLANT OWNED BY NGET

PLANT OWNED BY GENERATOR
DATA REQUIRED

PLANT OWNED BY GENERATOR
DATA NOT REQUIRED

FIGURE 5(c) – Example Power Park Module Single Line Diagram




The Single Line Diagram should also show any interconnection between the Unit and Station Boards that runs in parallel with the Transmission system.

Where the Power Station has auxiliary GTs, it would be helpful if the Single Line Diagram could show the normal point of connection of these machines. Where there are alternative connection points for such machines, this should also be shown.

The Single Line Diagram for a Power Park Module should include all parts of the System connecting generating equipment to the Grid Entry Point (or User System Entry Point if Embedded). Alternatively, the User may reduce the equipments between the equivalent Power Park Unit and the Common Busbar to an Equivalent Network. The Equivalent Power Park Unit connects the Equivalent Network at the Power Park Unit terminal.

In Figure 5(c), each different type of Equivalent Power Park Unit requires its own specific Equivalent Network. All the equipments including circuit breakers, transformers, cables and reactive compensation plant between the Common Collection Busbar and Substation should be represented in the Single Line Diagram.

## Lumped System Susceptance (PC.A.2.3)

This data refers only to susceptance associated with significant demands – i.e. station transformer demands. It is only likely to be of significance if there is a considerable demand (over 100 MW) associated with a large 132 kV cable network. For virtually all generators the value will be negligible. Note that the susceptance of any 275kV or 400kV equipment is not to be provided here, but will be included in the submission made under PC.A.2.4. (See below).

## Reactive Compensation Equipment (PC.A.2.4)

Please provide details of any reactive compensation equipment connected at 132kV or above. In most cases the value will be zero.

## Short-Circuit Infeed (PC.A.2.5)

Requirements for data on fault infeeds are discussed in Section V (Fault Infeeds).

## Three Winding Transformers

The GC requirements for data on transformers are, in most cases, sufficient for the needs of NGET. There are, however, a few cases when additional data is required in order to model transformer elements correctly. One such case is that of the three winding transformer, i.e. a transformer constructed with two secondary windings designed to carry load currents. The case of the transformer constructed as primary, secondary and tertiary is excluded from this category of three winding transformer.

For the three winding transformer, the following minimum data items are required:

- Rating of each winding (e.g. 90/45/45)
- Voltage Ratio (e.g. 132/13/13)
- Winding Arrangement (e.g. YDD)
- Positive Sequence Impedance (See below)
- Zero Sequence Impedance (Note that for a YDD winding arrangement, a single value of zero sequence impedance is appropriate)
- Tap Changer Range
- Step Size
- Type (On Load/Off Circuit)
- Tapped Winding

The positive sequence impedance of the transformer should be provided in the form of an "equivalent T" representation for the maximum, minimum and nominal tap positions. The values of the "equivalent T" can be readily calculated form the standard test measurements made on the transformer.

The impedance values should be quoted as a percentage **on the same MVA base.** This base may be the LV windings (45MVA in the above case) or in the case where all three windings have different ratings, the test certificate measurements may have to be converted to a consistent MVA base **before** the "equivalent T" is evaluated.
The values for an "equivalent T" which is based on the terminals of the three windings designated H, L1 and L2 should be provided as outlined below.

| | | $Z_H$ For The Equivalent T | $Z_{L1}$ For The Equivalent T | $Z_{L2}$ For The Equivalent T |
|---|---|---|---|---|
| Resistance | Max Tap<br>Min Tap<br>Nom Tap | | | |
| Reactance | Max Tap<br>Min Tap<br>Nom Tap | | | |

MVA Base For The Values Given: MVA

Switchgear (PC.A.2.2.6)
User's Supergrid Voltage Connecting System Data (PC.A.2.2.4)
Earthing Arrangements (PC.A.2.2.5.1)

The Data is required on the electrical components shown on the Single Line Diagram. This comprises:

(i) all lines and cables at 275kV or 400kV
(ii) all transformers with at least one voltage being 400kV or 275kV
(iii) all circuit breakers at 400kV or 275kV

The Schedule 5 Proforma for the return of this data is available to download from National Grid's website:

http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36875

If the transformer is sited within the NGET substation and connected to the GB Transmission by less than 100m of overhead connection, a data return saying "overhead connection less than 100m" is acceptable.

It should be noted that the information on generator transformers duplicates that in schedule 1 with the exception of the winding arrangements, and earthing details. In such circumstances a cross reference is acceptable.

Please note that, for switchgear, while the rated SC breaking current should be the symmetrical value, the rated SC making current should be the peak value.

Please refer to part I of this document (Guidance notes on Schedule 1) for notes on definition of transformer taps.

# PART V
# GUIDANCE NOTES ON FAULT INFEED DATA (SCHEDULE 14)

This section deals with fault infeed data (PC.A.2.5). This used to be provided on Schedule 13, but Revision 28 introduced a new Schedule 14, applicable to Generators; Schedule 13 is applicable to DNOs and non-embedded customers only.

Schedule 14 is in three parts. These deal with fault infeeds:

(i) through each unit transformer (see Page 7 for an explanation of Unit Transformer), expressed as data at the HV terminals of the Unit Transformer (i.e. the generator terminals). This will therefore include the fault infeeds from any generation or induction motors connected to the Unit Board. Data on fault infeeds from the main generator should NOT be included.
(ii) for each station transformer connection (see Page 7 for an explanation of station and unit transformers). Data should be supplied at the connection point (i.e. 400kV, 275kV or 132kV busbar).
(iii) for the whole Power Park Module and for each Power Park Unit type or its equivalent.

Where there is on-site demand being supplied through the User's System, this should be treated as though it was station transformer demand.

Figure 6 shows a typical 3 unit CCGT module. Auxiliary load is supplied by two unit transformers. The diagram shows the fault currents. (II, III) and X/R ratio required.

For a Power Park Module the maximum fault infeed under operating conditions is required, the fault current from all motors normally connected to the Power Park Unit's electrical system should be included. The fault infeed shall be specified at: a) the Power Park Unit terminal, or the Common Collection Busbar if an equivalent Single Line Diagram of the Power Park Module has been provided in DRC Schedule 5; b) the Grid Entry Point, or User System Entry Point if Embedded.

The positive, negative and zero sequence RMS fault current values should be provided for the above cases if the following solid faults happen at the Grid Entry Point, or User System Entry Point if Embedded. This data should include the effects of any protective control devices such as crowbars and an indication of whether the device has acted.

(i) a symmetrical three phase short circuit
(ii) a single phase to earth short circuit
(iii) a phase to phase short circuit
(iv) a two phase to earth short circuit

For a Power Park Module which utilises a protective control and the control is active, the above data shall also be submitted for the limiting case in which the protective device does not operate. In this case the retained voltages at

(i) the Power Park Unit terminal or the Common Collection Busbar, if appropriate
(ii) the Grid Entry Point or User System Entry Point if Embedded

shall be provided in the limiting case where the protective control is not active. This may imply a non-solid fault.

The fault currents and retained voltages should be provided from the time of fault inception to 140ms afterwards. They should be supplied as both a continuous trace and a table giving the values at 10ms intervals. If the actual fault infeeds are not available at the time of the application for a CUSC Contract or Embedded Development Agreement, the fault current for both single phase and three phase solid faults at the time of fault application and at 50ms should be submitted as a minimum requirement. Actual data shall be submitted to NGET as soon as it is available, in line with PC.A.1.2.

A table of fault currents and retained voltages required for Power Park Module is shown below. The shaded area in the table indicates the minimum data which shall be submitted at the time of application for a CUSC contract.

| | | 0ms | 10 | 20 | 30 | 40 | 50 | 60 | 70 | 80 | 90 | 100 | 110 | 120 | 130 | 140 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3Φ Fault | PPS current | | | | | | | | | | | | | | | |
| | NPS current | | | | | | | | | | | | | | | |
| | ZPS current | | | | | | | | | | | | | | | |
| 1Φ-E Fault | PPS current | | | | | | | | | | | | | | | |
| | NPS current | | | | | | | | | | | | | | | |
| | ZPS current | | | | | | | | | | | | | | | |
| 2Φ Fault | PPS current | | | | | | | | | | | | | | | |
| | NPS current | | | | | | | | | | | | | | | |
| | ZPS current | | | | | | | | | | | | | | | |
| 2Φ-E Fault | PPS current | | | | | | | | | | | | | | | |
| | NPS current | | | | | | | | | | | | | | | |
| | ZPS current | | | | | | | | | | | | | | | |

| | 0ms | 10 | 20 | 30 | 40 | 50 | 60 | 70 | 80 | 90 | 100 | 110 | 120 | 130 | 140 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PPS retained voltage | | | | | | | | | | | | | | | |
| NPS retained voltage | | | | | | | | | | | | | | | |
| ZPS retained voltage | | | | | | | | | | | | | | | |

## X/R Ratio (PC.A.2.5.6)

This should be provided in all cases.

## Pre-fault Voltage (PC.A.2.5.6)

This should be provided if the value is not 1.0p.u.

## Short Circuit Current Infeeds (PC.A.2.5.6)

The short-circuit current infeed at both instant of fault, and after the decay of the subtransient component, is required. The current should be given in kA.

## Time Constants (PC.A.2.5.6)

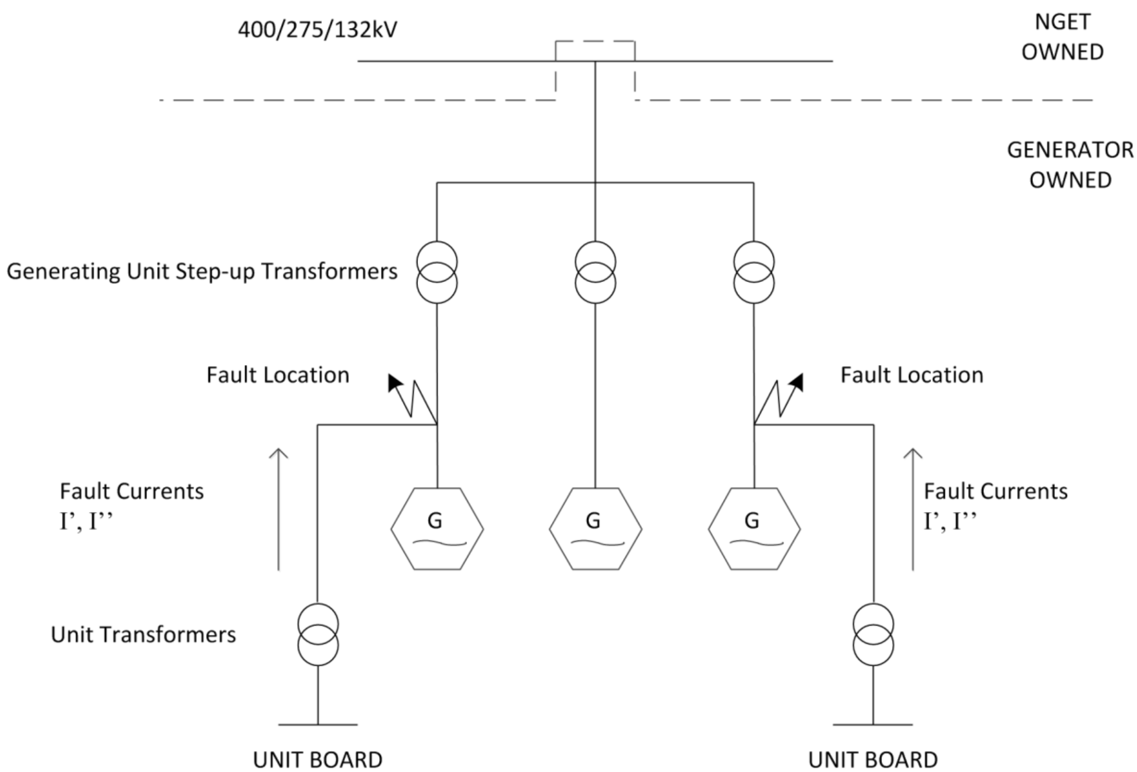
The GC (PC.A.2.5.6.(b)) assumes that the time constant for the decay of the subtransient fault current is not significantly different from 40ms. If it is significantly different, please give the actual value.

## Minimum Zero Sequence Source Impedance (PC.A.2.5.6)

The minimum zero sequence impedance (both reactance and resistance) is only required if the transformer (either unit or station) can supply zero sequence current to the Transmission system. In practice Generating Unit step-up transformers are normally star-delta and cannot supply zero sequence current and no data is required. Station transformers, however, are generally star-star and do provide a zero sequence path, and data is therefore required for station transformer connections.

The calculation of minimum zero sequence impedance will depend upon the double wound transformers connecting the GB Transmission high voltage system (i.e. 400kV or 275kV throughout GB and also 132kV in Scotland) to the Users primary voltage system, (generally 6.6kV, 11kV or 23kV), the earthing arrangements on the Users System and the interconnectivity between connection points at a single site.

## FIGURE 6 – Fault Infeed from Typical Modular CCGT



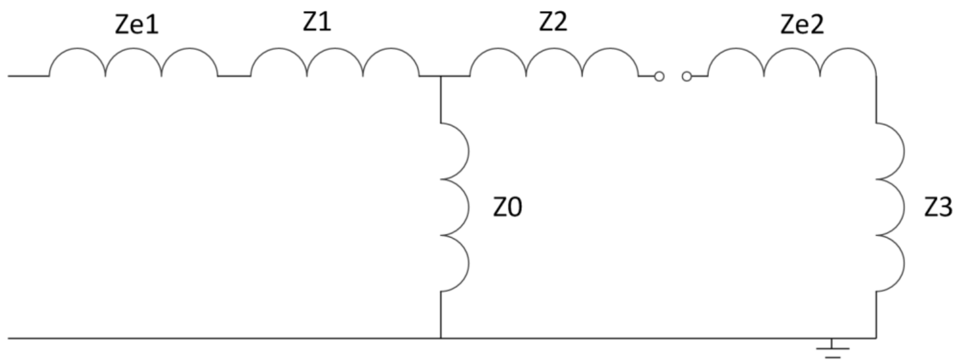

At the instant of fault:

- Equivalent X/R ratio of Unit Transformer and all auxiliary equipment attached to Unit Board is required.

- If Generating Unit Step-up Transformer is star-delta connected, minimum zero sequence impedance of auxiliary system is not required (zero sequence current cannot pass through)

If the transformer is 'star-star', the normal arrangement for station transformers, the minimum zero sequence impedance of the connection point can be derived by considering the following diagram:

## FIGURE 7 – ZPS Transformer Impedances for Star-Star Connection




where:

$Z_o$, $Z_1$, $Z_2$, are the zero sequence 'equivalent - T' model of the star-star transformer (see below for derivation).

$Z_{E1}$ is **three times** the impedance of the connection between the HV star point and earth. Under normal circumstances, this will be zero as the HV system is solidly earthed.

$Z_{E2}$ is **three times** the impedance of the connection between the LV star point and earth and will be zero if the star point is directly earthed and infinite if the 'star-point' is unearthed. This impedance should be calculated based on rated LV voltage.

$Z_3$ is the zero sequence impedance of the Users System connected to the LV of the transformer. Note that this value can be infinite if the Users System connected to the LV side of the transformer is unearthed. (This situation can arise if there is only 'delta' connected equipment or if 'star' connected equipment does not have the 'star point' earthed.

The zero sequence 'T' equivalent of the transformer can be derived from standard tests as follows:

| | hv Windings | lv Windings | Neutrals | Tertiary (if present) | Test Voltage | NDC Reference |
|---|---|---|---|---|---|---|
| $Z_{OH-T//N}$ | shorted | o/c | connected | closed | hv to neutral | 197 |
| $Z_{OL-T//N}$ | o/c | Shorted | connected | closed | lv to neutral | 202 |
| $Z_{OL-H//T//N}$ | shorted to neutral | Shorted | connected | closed | lv to neutral | 207 |
| $Z_{OH-L//T//N}$ | shorted | Shorted To neutral | connected | closed | hv to neutral | 212 |

o/c = open circuit
"shorted" means that the 3 terminals are shorted together
"shorted to neutral" means that the 3 terminals are shorted, and connected to neutral.
"closed" means that the 3 delta windings are connected together to give a continuous current path round all 3 phases.
"connected" means that the two neutrals are connected together.

"NDC Reference" is the reference in the old CEGB National Data

Catalogue. From these measurements, ZO may be calculated as:

$$ZO = \{ZOH\text{-}T,,N\,(ZOL\text{-}T,,N - ZOL\text{-}H,,T,,N)\}^{1}/_{2}$$

$$= \{ZOL\text{-}T,,N\,(ZOH\text{-}T,,N - ZOH\text{-}L,,T,,N)\}^{1}/_{2}$$

The two values are theoretically identical but will differ due to measurement error and an average value should be taken.

The values of Z1 and Z2 can now be calculated as:

$$Z1 = ZOH\text{-}T,,N - ZO$$

$$Z2 = ZOL\text{-}T,,N - ZO$$

Note that the effects of transformer taps are such that these impedances may vary. Users should select the tap position that gives the lowest zps impedances.

The minimum zero sequence impedance of this type of connection can now be calculated by considering Z0, Z1, Z2, Z3, $Z_{e1}$ and $Z_{e2}$ as a series parallel network.

<u>Note</u>
Zero sequence resistance and reactance values are requested in the schedule 14 tables. In the absence of better information, estimation of resistance and reactance values may be made by assuming that the X:R ratio is the same as for the positive phase sequence.

# PART VI
# GUIDANCE NOTES ON OFTO SYSTEM DATA (SCHEDULE 18)

Schedule 18 of the DRC deals with OFTO (Offshore Transmission Owner) System Data. Schedule 18 requires data for the User's Network and data for fault infeeds, and as such it combines requirements from DRC Schedule 5 and DRC Schedule 14. The requirements for Schedule 5 are discussed in Part IV of this document, and Schedule 14 in Part V.

Figure 7 shows a typical OFTO system layout. Offshore equipment with any voltage levels of 132kV or above is considered to be transmission equipment. For offshore networks, the OTSDUW (Offshore Transmission System Development User Works) is a common arrangement. This is where the offshore network and offshore wind farm have been constructed by the same company. The offshore network is subsequently handed over to the OFTO as part of the transitioning process. Ownership of the wind farm is retained by the original developer.

Interface Point

Figure 8 shows the boundaries of the OFTO network. In Figure 7 there are two boundaries shown: the Transmission Interface Point (TIP), and the Grid Entry Point (GEP). The TIP is the onshore point of connection. The OFTO network can either be connected to the onshore transmission system or an onshore distribution system. The GEP is the offshore connection point. This is where the OFTO network connects to one or more offshore wind farms.

Interface Point Capacity

The Interface Point Capacity is the maximum amount of Active Power transferrable at the Interface Point (the TIP in Figure 7). This must be submitted in schedule 18 (paragraph PC.A.3.2.2 of the Planning Code refers). Customers are requested to submit the Interface Point Capacity on a per-circuit basis, if this data is available. The following pro-forma is intended to assist with this process:

<table>
<tr>
<td>Interface Point Capacity<br>(PC.A.3.2.2 (a))<br><br>[#MW] under Normal Running Arrangement ([Voltage]kV bus section open) and [#MW] if there is an onshore [Voltage]/[Voltage]kV transformer outage ([Voltage]kV bus section closed). NOTE: Combined Interface Point Capacity between [identify first entry point] and [identify second entry point] can never exceed [#MW].<br><br>Between [-#MVAr] and [+#MVAr] under Normal Running Arrangement ([Voltage]kV bus section open) at Rated MW depending on MVAr demand at TIP.<br>Between [-#MVAr] and [+#MVAr] if there is an onshore [Voltage]/[Voltage]kV transformer outage ([Voltage]kV bus section closed).</td>
<td>MW<br><br>MVAr</td>
<td></td>
<td></td>
<td></td>
<td>The table below shows the Interface Point Capacity (IPC) for each 400kV point of connection at [NAME] [Voltage]kV substation:<br><br>
<table>
<tr><td rowspan="2">Running Arrangement</td><td colspan="2">[identify first entry point]</td><td colspan="2">[identify second entry point]</td></tr>
<tr><td>P (MW)</td><td>Q (MVAr)</td><td>P (MW)</td><td>Q (MVAr)</td></tr>
<tr><td>Normal Operation</td><td></td><td></td><td></td><td></td></tr>
<tr><td>SGT 1 Outage</td><td></td><td></td><td></td><td></td></tr>
<tr><td>SGT 2 Outage</td><td></td><td></td><td></td><td></td></tr>
</table>
</td>
</tr>
</table>

<u>Single Line Diagram</u>

OFTOs are asked to provide a Single Line Diagram (SLD) showing the layout of their system. The level of detail required is that shown in Figure 7. The SLD must show all offshore transmission equipment that forms part of the offshore transmission system. Offshore equipment with any voltage levels of 132kV or above is considered to be transmission equipment.

The SLD should show the boundary between the OFTO and the wind farm (Connection Point), and the boundary between the OFTO and NGET or the onshore TO (Interface Point).

<u>User System Data</u>

The Grid Code requires the OFTO to submit data for all offshore transmission equipment shown on the SLD. This will include all equipment connected between the Interface Points, and will consist mainly of:

- Busbars and substation infrastructure
- circuits
- transformers
- switchgear
- reactive compensation
- harmonic filters

Schedule 18 provides a table for each of the above equipment types. The data requirements are similar to those for schedule 5, and are discussed in Part IV. However, there may be some differences for Schedule 18. For instance:

- Offshore equipment operating at 132kV or above is considered to be transmission equipment, and
- circuit data must include the length of each circuit in km.

Fault Infeeds

Fault infeed data should be submitted by each OFTO for faults at the boundaries of the OFTO network at:

- the boundary between the OFTO and each wind farm connection point (the GEP in Figure 7), and
- the boundary between the OFTO and NGET or the onshore TO (the TIP in Figure 7)

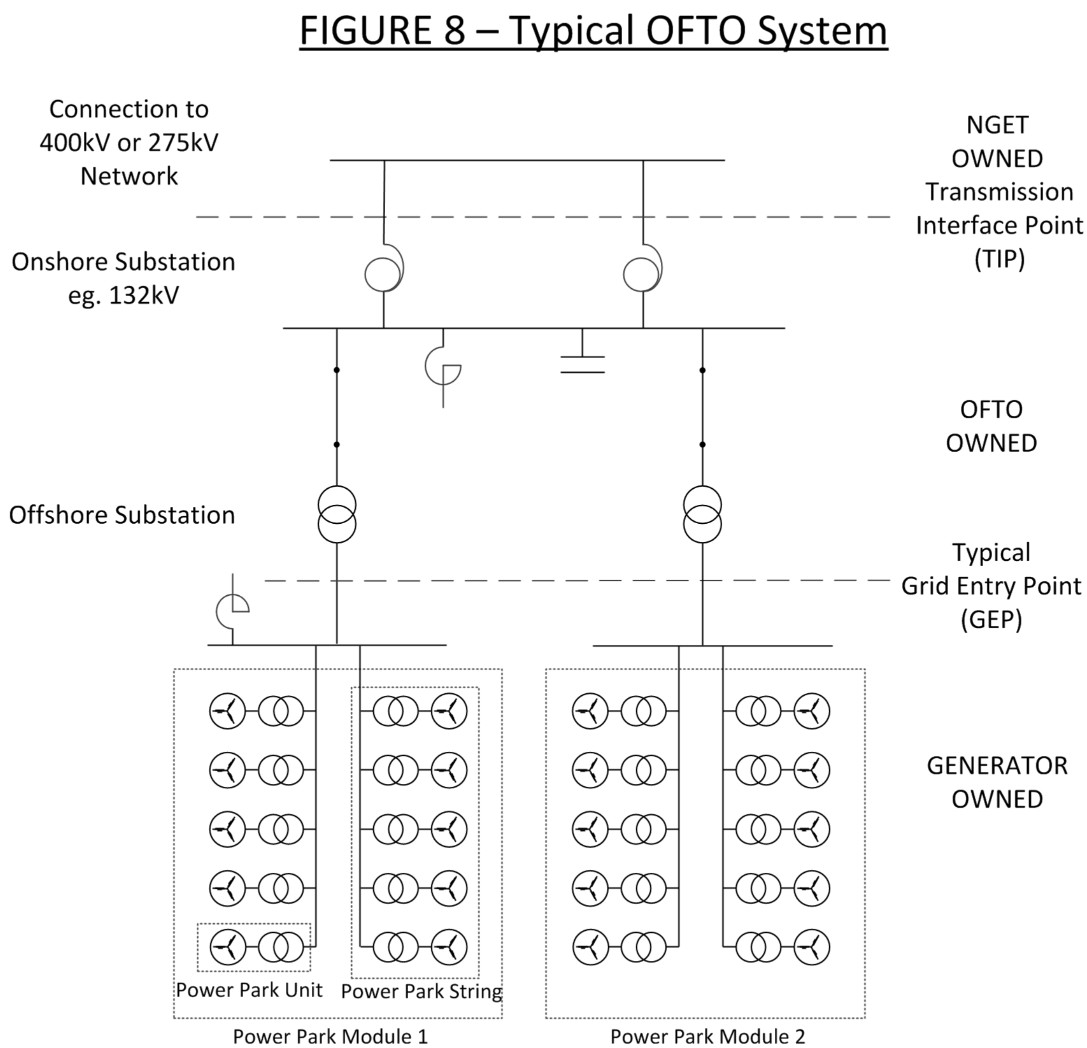
The maximum fault infeed is required.

The requirements for fault infeeds for schedule 18 are similar to those for Power Park modules in Schedule 14 discussed in Part V. Schedule 18 requires traces from simulations of fault-ride through performances.

DC Converters

If the OFTO network includes a DC Converter, then data should be submitted as per section PC.A.5.4.3 of the Planning Code, including transformer and harmonic filter parameters, and control system models.

**Figure 8 – Typical OFTO System Layout**



## PART VII - CONTACT DETAILS

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