NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

GADS Wind Turbine Generation

Data Reporting Instructions

Version 1.1 – June 2015
Effective Date January 1, 2017

RELIABILITY | ACCOUNTABILITY




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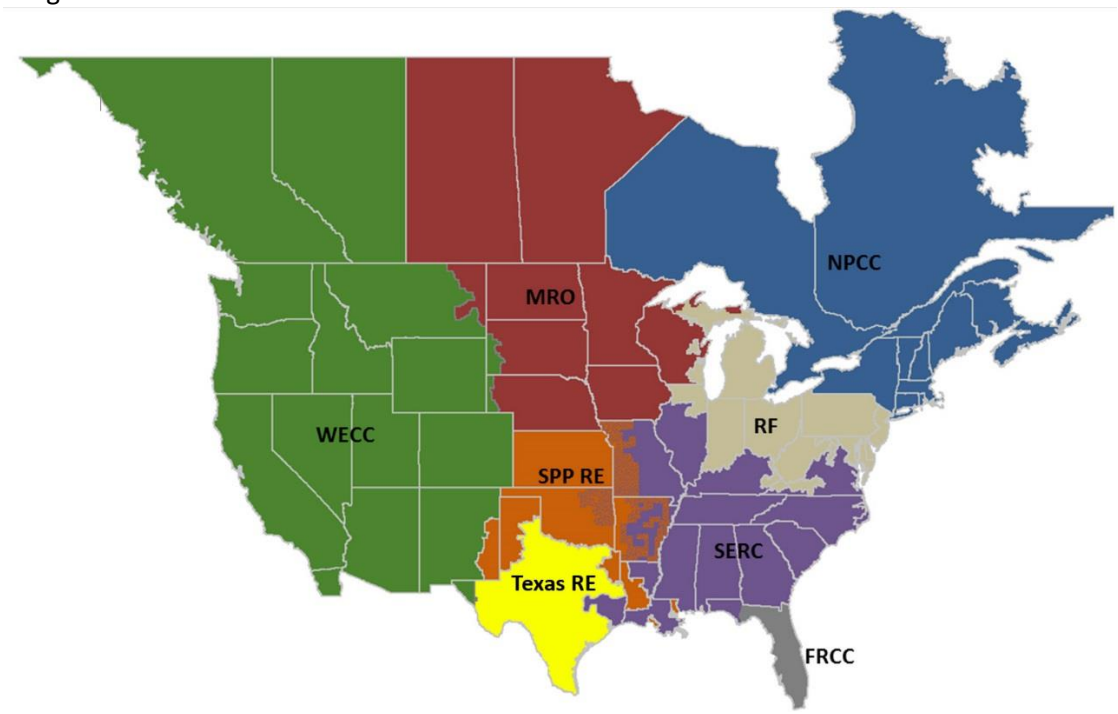
Revision History

Version	Date	Effective Date	Revisions
1.0	1/15/2015		Initial Release
1.1	6/2/2015	1/1/2017	Updated in response to public comments

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

These *GADS Wind Turbine Generation (GADS-W) - Data Reporting Instructions* were developed to assist plant personnel in reporting information to the North American Electric Reliability Corporation's (NERC) GADS-W database. The instructions detail the procedures, schedule and format to follow when reporting data to the wind turbine database.

Who Must Report

GADS-W is mandatory for all Generator Operators on the NERC registered entities that operate wind turbine facilities of 75 MW or greater and a Commissioning date of January 1, 2005. Participating organizations must be prepared to commit the necessary effort to provide timely, accurate, and complete data. The reporting instructions detail the data elements collected by GADS-W and have been identified by the industry as being vital to the understanding and interpretation of wind turbine performance.

FRCC Florida Reliability Coordinating Council	SERC SERC Reliability Corporation
MRO Midwest Reliability Organization	SPP Southwest Power Pool
NPCC Northeast Power Coordinating Council	TRE Texas Regional Entity
RF Reliability First	WECC Western Electricity Coordinating Council

Figure 1: Regional Entities

Data Release Guidelines

The GADS-W Data Release Guidelines can be found in *Appendix A*.

What will be reported?

1. Plant Data – Initial and whenever there is a change.
2. Group Data – Initial and whenever there is a change.
3. Sub-Group Data – Initial and whenever there is a change.
4. Performance Data – At the Sub-Group Level
5. Component Data - Optional

When will Reporting Begin

January 1, 2017 (Data may be submitted voluntarily at an earlier date if NERC is ready to accept data)

Phased in Approach

1. Year one – Voluntary Reporting
2. Year two – 200 MW or larger plants
3. Year three – 100 MW to 199 MW plants
4. Year four – less than 100 MW plants

Note: Any plant of any size may report at any time on a voluntary basis.

Chapter 1 – Data Transmittal and Format

Transmittal

There are five different types of data files that you will need to submit:

1. Plant
2. Group
3. Sub-Group
4. Performance
5. Component Outage

Before submitting the component outage and performance data for your wind plants, you must report the plant, group, and sub-group data for each plant to the GADS-W database. You only need to provide the plant, group, and sub-group data initially when you begin reporting data for each plant, and then update it when the characteristics of the plant change. We strongly recommend that all five of the files be reviewed and reported with each quarterly submittal. This data provides information regarding installed equipment, design, and operating characteristics of the plant that are used in when completing special analysis.

Once the plant, group, and sub-group data have been reported to the GADS-W database, you can begin to report the component outage and performance data. Submit the component outage and performance data to GADS-W within 45 days after the end of every calendar quarter through gads@nerc.net. Report this data throughout the life of each plant.

Format

Data should be submitted to NERC in CSV (comma-separated-value) file format. CSV is a common file type used to import data from one software application to another, with commas or tabs separating the values in each record. Please ensure that all values are not formatted with any punctuation other than a decimal point and slashes used in dates, for example, numbers with embedded commas can cause problems such as 12,000.25. In this example, the value should be reported as 12000.25.

The CSV files should be saved with the name of the data type (ex. plant.csv, group.csv, subgroup.csv, performance.csv, component.csv) as part of the file name to easily differentiate between them. Also include the Plant ID in the file name. Plant ID's are discussed in *Section 3*.

Wind Generation Data Entry Software

NERC has developed the *Wind Generation Data Entry* software to assist with the collection of wind generation data. The software, along with the accompanying *Wind Generation Data Entry Software User Manual,* is available free of charge from NERC's web site:

http://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.aspx

Questions and Comments

All questions regarding data transmittals and reporting procedures should be directed to gads@nerc.net.

Chapter 2 – Plants, Groups, and sub-groups

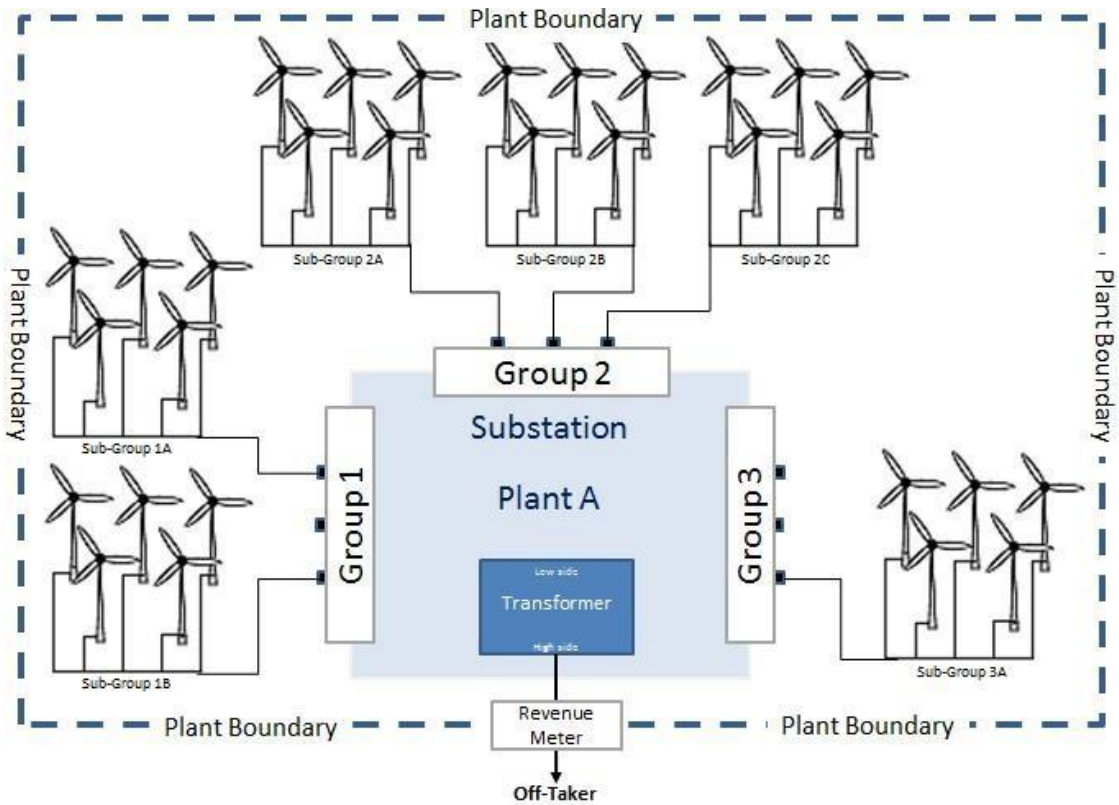


Figure 2: Typical Wind Plant Layout

In Figure 2, the diagram represents a typical plant with the plant boundary at the revenue meter. Groups usually represent different phases of development. For example, in Group 1 there are two sub-groups, where each sub-group contains different turbine types installed the same year. If a sub-group is repowered, the sub-group is retired and a new sub-group created under the same group. GADS-W recognizes that there are many potential layouts of wind plants, so there are no strict rules for plant, group, and sub-group layout other than a sub-group can only contain turbines of a specific make, model, version, and commissioning date.

Although Figure 2 shows the sub-groups as being electrically isolated, this need not be the case. A feeder may have multiple turbine types. The plant is responsible for allocating production and hourly distributions using feeder meters, turbine meters, SCADA systems, manual logs, or other means into the proper sub-groups.

Plant Boundaries

The following is taken from the *GADS Data Reporting Instructions* as a suggestion of plant boundaries:

> There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control.

The following describes what equipment a generating unit includes in preferred order:

1. The preferred plant boundary at the revenue meter is usually at the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers

2. In cases of multiple sub-groups, the plant boundary would be at the metering of the low side of the substation transformer (load) side of the generator voltage circuit breakers
3. Any equipment boundary that is reasonable considering the design and configuration of the generating unit.

Plants

A plant is defined as a collection of wind turbine groups at a single physical location. There may be any number of wind turbine groups at a wind plant. You only need to provide the plant data to NERC initially when you begin to report data for each plant or anytime any changes to the plant are made.

Plant Record Layout (CSV Format)

Table 1: Plant Record Layout		
Column	**Field Name**	**Entry Type**
1	Plant ID	Alpha-Numeric – 10
2	Plant Name	Alpha-Numeric – 45

Plant ID (Column 1)

With help from NERC staff, enter a unique ID for the plant that you are reporting. This ID is referenced in all groups, sub-groups, performance, and component data existing under the plant.

Plant Name (Column 2)

With help from NERC staff, enter a unique name, which may be more descriptive than the Plant ID, given to the plant that you are reporting.

Groups

A group is one or more sub-groups that are contained within a common plant boundary. There may be any number of groups per wind plant. Groups are usually phases that are commissioned during a particular year. Each group has a unique number that identifies it as part of a particular wind plant. Each group will have a unique turbine group ID that will be associated with its child sub-group. The reporting utility assigns this ID.

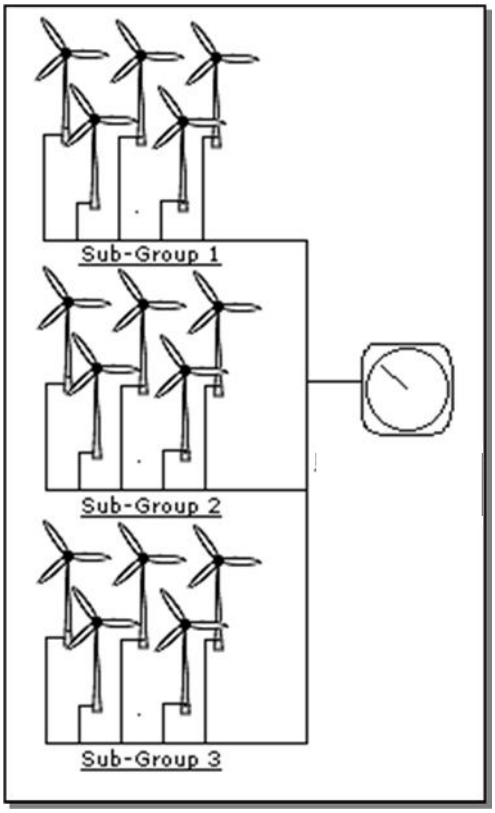


Figure 3: Wind Turbine Groups

Wind Turbine Group

Groups report the following site data:

- Associated Plant ID
- Turbine Group ID
- Turbine Group Name
- NERC Utility Code
- NERC Unit Code
- ISO Resource ID
- Installed Capacity
- Auxiliary Capacity
- Commissioning Year
- Country
- Nearest City
- State / Province
- Location Longitude and Latitude
- Elevation
- Wind Regime (topography)
- Annual Average Wind Speed
- SCADA Manufacturer
- SCADA Model

Note: The ISO Resource ID is listed at the Group level. If you have multiple ISO Resource ID's you may want to consider how you lay your groups out. The ISO Resource ID is used to link your group of plants with an ISO in the event your ISO requires mandatory GADS reporting.

Group Record Layout (CSV Format)

Table 2: Group Record Layout		
Column	**Field Name**	**Entry Type**
1	Associated Plant ID	Alpha-Numeric – 10
2	Turbine Group ID	Alpha-Numeric – 10
3	Turbine Group Name	Alpha-Numeric – 45
4	NERC Utility Code	Alpha-Numeric – 3
5	NERC Unit Code	Alpha-Numeric – 3
6	ISO Resource ID	Alpha-Numeric - 30
7	Installed Capacity	Numeric - 8 + 2 decimals
8	Auxiliary Capacity	Numeric - 8 + 2 decimals
9	Commissioning year	Alpha-Numeric - 4
10	Country	Alpha-Numeric - 2
11	Nearest City	Alpha-Numeric - 40
12	State/Province	Alpha-Numeric - 2
13	Location Longitude	Numeric - 4 + 4 decimals
14	Location Latitude	Numeric - 3 + 4 decimals
15	Elevation	Numeric - 8 + 2 decimals
16	Wind Regime (topography)	Numeric - 3
17	Annual Average Wind Speed (AAWS)	Numeric – 3 + 2 decimals
18	Left Blank Intentionally	Alpha-Numeric - 10
19	SCADA Manufacturer	Alpha-Numeric - 5
20	SCADA Model	Alpha-Numeric - 10

Group ID

Plant ID (Column 1)
Enter the Plant ID as previously defined.

Group ID (Column 2)
Enter a unique ID for the group that you are reporting. This ID is referenced in all sub-groups, performance data, and hours data existing under the group.

Group Name (Column 3)
Enter the name given to the group that you are reporting.

NERC Utility Code (Column 4)
Enter the three character alpha-numeric code NERC assigned to your utility. *Appendix B* contains a guide for selecting utility codes.

NERC Unit Code (Column 5)
Enter the three character alpha-numeric code your utility assigned for the unit that you are reporting. This code distinguishes one plant from another in your utility. *Appendix B* contains a guide for selecting unit codes.

ISO Resource ID (Column 6)
If applicable, enter the unique identifier given to the group by the ISO(s).

Capacity (Column 7)
Enter the total capacity for the entire group, measured in megawatts (MW). For example, one hundred 1 MW Type A turbines would have an installed capacity of 100 MW.

Auxiliary Capacity (Column 8)
Enter the combined capacities for all the auxiliary turbines (spare turbines) not normally connected, and not part of Gross Installed Capacity (GIC), measured in megawatts (MW).

Commissioning year (Column 9)
Enter the year (YYYY), that the first sub-group came online and entered into active status.

Location

Country (Column 10)
Using Table 1 in *Appendix F*, enter the two-letter country abbreviation where the group is located. We recommend that all values reported to NERC match any values that also must be reported to other agencies such as the EIA, EPA.

Nearest City (Column 11)
Enter the name of the nearest major city closest in proximity to the group.

State /Province (Column 12)
Using Tables 1&2 in *Appendix F*, enter the two-letter State/Province abbreviation where the group is located.

Longitude (Column 13)
Enter the degrees of longitude of the physical location of the group[1].

Latitude (Column 14)
Enter the degrees of latitude of the physical location of the group[1].

Elevation (Column 15)
Enter the elevation of the physical location of the group, given in meters[1].

Wind/Site Characteristics

Wind Regime (Column 16)
Using Table 3 in *Appendix F*, enter the average topography of the area in which the group is located.

Annual Average Wind Speed (Column 17)
Enter the annual average wind speed (AAWS) at 80 m, measured in meters per second.

SCADA System (Column 18)
Column 18 is left intentionally blank.

[1] The degrees of longitude, latitude, and elevation may be taken anywhere on the site that is meaningful to the reporting entity. This could be the revenue meter, main structure, or geographic center of the group.

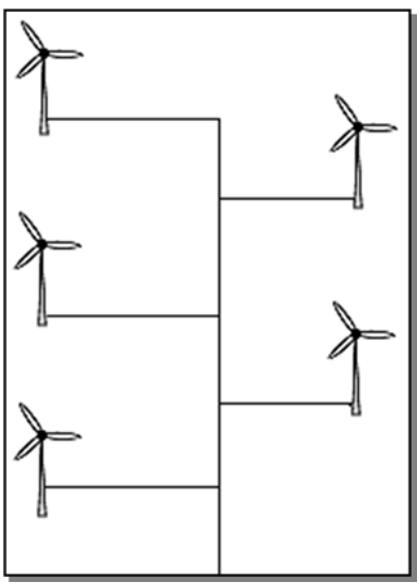
SCADA Manufacturer (Column 19)
Using Table 4 in *Appendix F*, enter the manufacturer of the SCADA system. We recommend that all values reported to NERC match any values that also must be reported to other agencies such as the EIA, EPA, etc.

SCADA Model (Column 20)
Enter the model name of the SCADA system.

Sub-Groups

A sub-group is a collection of wind turbine machines with the same manufacturer, designs, model number, and phase of construction. Each sub-group will have a unique identifier and be associated with its parent group. The sub-group should submit component outage and performance data.

For example, suppose that manufacturers A, B, and C supply your utility with turbines. Your group contains 27 A turbines, as well as 100 B turbines constructed in 2000. In 2013, the 100 B turbines were replaced with 10 C turbines. The A, B, and C turbines would be three separate sub-groups under the same group. When all the B turbines are replaced, their sub-group would be put into an inactive status."



Wind Turbine Sub-Group
Sub-groups report the following design data:

- Plant, Group and Sub-Group ID
- NERC Utility and Unit Codes
- Sub-Group Number and Name
- Commissioning Year
- Nameplate Capacity
- Total number of Turbines
- Turbine Manufacturer
- Make
- Model
- Rotor Height and Diameter
- Cut-in and Cut-out Wind Speed
- Turbulence Intensity
- Wind Speed Range
- Wind Shear
- Reference Anemometer Height
- Minimum Operating Temperature
- Maximum Operating Temperature

Sub-Group Record Layout (CSV Format)

Column	Field Name	Entry Type
1	Plant ID	Alpha-Numeric - 10
2	Group ID	Alpha-Numeric - 10
3	Sub-Group ID	Alpha-Numeric - 10
4	NERC Utility Code	Alpha-Numeric - 3
5	NERC Unit Code	Alpha-Numeric - 3
6	Sub-Group Number	Numeric - 3
7	Sub-Group Name	Alpha-Numeric - 45

Column	Field Name	Entry Type
8	Commissioning Year	Numeric - 4
9	Nameplate Capacity	Numeric - 3 + 3 decimals
10	Total Number of Turbines	Numeric - 7
11	Turbine Manufacturer	Alpha-Numeric - 5
12	Model	Alpha-Numeric - 20
13	Version	Alpha-Numeric - 20
14	Rotor Height (meters)	Numeric - 7 + 2 decimals
15	Rotor Diameter (meters)	Numeric - 7 + 2 decimals
16	Cut-in Wind Speed (meters/second)	Numeric - 7 + 2 decimals
17	Low Cut-out Wind Speed (meters/second)	Numeric - 7 + 2 decimals
18	High Cut-out Wind Speed (meters/second)	Numeric - 7 + 2 decimals
19	Turbulence Intensity	Numeric - 3
20	Average Wind Speed	Numeric – 3 +2 decimal
21	Wind Shear (Optional)	Numeric - 3
22	Reference Anemometer Height (meters) (Optional)	Numeric - 3
23	Minimal Operating Temperature (Celsius)	Numeric - 3
24	Maximum Operating Temperature (Celsius)	Numeric - 3

Sub-Group ID

Plant ID (Column 1)

Enter the Plant ID as previously defined.

Group ID (Column 2)

Enter the Group ID as previously defined.

Sub-Group ID (Column 3)

Enter a unique ID for the sub-group that you are reporting. This ID is referenced in all performance and component data existing under the sub-group.

NERC Utility Code (Column 4)

Enter the three character alpha-numeric code NERC assigned to your utility. *Appendix B* contains a guide for selecting utility codes.

NERC Unit Code (Column 5)

Enter the three character alpha-numeric code your utility assigned for the unit that you are reporting.

Sub-Group Number (Column 6)

The sub-group number identifies all the individual sub-groups within a parent group. Each sub-group is assigned a unique code as they are entered starting with 1 through 999.

Sub-Group Name (Column 7)

Enter the name given to the sub-group that you are reporting.

Commissioning Year (Column 8)

Enter the year (YYYY) that the sub-group was commissioned.

Nameplate Capacity (Column 9)
Enter the individual turbine capacity, or megawatt (MW) rating, of the typical wind turbine in the group.

Total Number of Turbines (Column 10)
Enter the actual number of physical turbines that exist in the sub-group.

Typical Design

Manufacturer (Column 11)
Using Table 5 in *Appendix F*, enter the name of the manufacturer of the turbines in the sub-group.

Model (Column 12)
Enter the model of the make of the turbines in the sub-group.

Version (Column 13)
Enter the version name of the turbines in the sub-group.

Rotor Height (Column 14)
Enter the height of the rotor hub, given in meters.

Rotor Diameter (Column 15)
Enter the diameter of the rotor, given in meters.

Cut-in Wind Speed (Column 16)
Enter the lowest wind speed that the turbine will start to generate power, in meters per second.

Low Cut-out Wind Speed (Column 17)
Enter the lowest wind speed that the turbine can continue to generate power before cutting out.

High Cut-out Wind Speed (Column 18)
Enter the highest wind speed at which the turbine is capable of generating power before cutting out.

Turbine Wind Class

Turbulence Intensity (Column 19)
Using Table 6 in *Appendix F*, select the average wind turbulence where the sub-group is located.

Average Wind Speed (Column 20)
Enter the average annual wind speed (AAWS) at 80m, measured in meters per second.

Wind Shear (Optional) (Column 21)
Using Table 7 in *Appendix F*, select the average strength of the difference between the speeds of wind.

Reference Anemometer Height (Optional) (Column 22)
Height of the highest anemometer on the reference meteorological tower.

Minimum Operating Temperature (Column 23)
Enter the manufacture minimum operating temperature in degrees Celsius.

Maximum Operating Temperature (Column 24)
Enter the manufacture maximum operating temperature in degrees Celsius.

Chapter 3 – Performance Reporting

Performance data provide sub-group information, in a summarized format, pertaining to overall wind turbine operation during a particular month in a given year. These data are needed to calculate sub-group, group and plant performance, reliability and availability statistics. Performance data are required for all unit types and sizes reported to the GADS-W program.

Performance Record Layout (CSV Format)

Column	Field Name	Entry Type	Mandatory or Optional
1	Plant ID	Alpha-Numeric - 10	Mandatory
2	Group ID	Alpha-Numeric - 10	Mandatory
3	Sub-Group ID	Alpha-Numeric - 10	Mandatory
4	NERC Utility Code	Alpha-Numeric - 3	Mandatory
5	NERC Unit Code	Alpha-Numeric - 3	Mandatory
6	Report Period (month)	Numeric - 2	Mandatory
7	Report Year	Numeric - 4	Mandatory
8	Sub-Group Status	Alpha-Numeric - 2	Mandatory
9	Gross Actual Generation (GAG)	Numeric - 10 + 2 decimals	Mandatory
10	Net Actual Generation (NAG)	Numeric - 10 + 2 decimals	Mandatory
11	Net Maximum Capacity (NMC)	Numeric - 8 + 2 decimals	Mandatory
12	Period Turbine-Hours (PDTH)	Numeric - 10 + 2 decimals	Mandatory
13	Contact Turbine-Hours (CTH)	Numeric - 12 + 2 decimals	Mandatory
14	Reserve Shutdown Turbine-Hours (RSTH)	Numeric - 10 + 2 decimals	Mandatory
15	Forced Turbine-Hours (FTH)	Numeric - 10 + 2 decimals	Mandatory
16	Maintenance Turbine-Hours (MTH)	Numeric - 10 + 2 decimals	Mandatory
17	Planned Turbine-Hours (PTH)	Numeric - 10 + 2 decimals	Mandatory
18	OMC Forced Turbine-Hours (oFTH)	Numeric - 10 + 2 decimals	Mandatory
19	OMC Maintenance Turbine-Hours (oMTH)	Numeric - 10 + 2 decimals	Mandatory
20	OMC Planned Turbine-Hours (oPTH)	Numeric - 10 + 2 decimals	Mandatory
21	Resource Unavailable Turbine-Hours (RUTH)	Numeric - 10 + 2 decimals	Mandatory
22	Inactive Reserve Turbine-Hours (IRTH)	Numeric - 10 + 2 decimals	Mandatory
23	Mothballed Turbine-Hours (MBTH)	Numeric - 10 + 2 decimals	Mandatory
24	Retired Unit Turbine-Hours (RTH)	Numeric - 10 + 2 decimals	Mandatory
25	Blank	Blank	Blank
26	Blank	Blank	Blank
27	Blank	Blank	Blank
28	Blank	Blank	Blank
29	Blank	Blank	Blank
30	Blank	Blank	Blank
31	Equivalent Forced Derated Turbine Hours (EFDTH)	Numeric - 10 + 2 decimals	Optional
32	Equivalent Maintenance Derated Turbine Hours	Numeric - 10 + 2 decimals	Optional
33	Equivalent Planned Derated Turbine Hours (EPDTH)	Numeric - 10 + 2 decimals	Optional
34	OMC Equivalent Forced Derated Turbine Hours (oEFDTH)	Numeric - 10 + 2 decimals	Optional

Column	Field Name	Entry Type	Mandatory or Optional
35	OMC Equivalent Maintenance Derated Turbine Hours	Numeric - 10 + 2 decimals	Optional
36	OMC Equivalent Planned Derated Turbine Hours	Numeric - 10 + 2 decimals	Optional
37	Equivalent Reserve Shutdown Derated Turbine Hours (ERSDTH) (Optional)	Numeric - 10 + 2 decimals	Optional
38	Forced Delay Turbine Hours (FDTH)(Optional)	Numeric - 10 + 2 decimals	Optional
39	Maintenance Delay Turbine Hours (MDTH)(Optional)	Numeric - 10 + 2 decimals	Optional
40	Planned Delay Turbine Hours (PDTH) (Optional)	Numeric - 10 + 2 decimals	Optional

Plant ID (Column 1)
Enter the Plant ID as previously defined.

Group ID (Column 2)
Enter the Group ID as previously defined.

Sub-Group ID (Column 3)
Enter the sub-group ID as previously defined.

NERC Utility Code (Column 4)
Enter the three character alpha-numeric code NERC assigned to your utility. See *Appendix B*

NERC Unit Code (Column 5)
Enter the three character alpha-numeric code your utility assigned for the plant that you are reporting. This code distinguishes one plant from another in your utility. See *Appendix B*.

Report Period (Column 6)
Enter the two-digit month (MM) in which the performance data is being entered.
See *Appendix F* Table 8

Report Year (Column 7)
Enter the four-digit year (YYYY) in which the performance data is being entered.

Sub-Group Status (Column 8)
From the table below, select the status of the entire sub-group during the year/period for which the data is entered. See *Appendix F* Table 9

Capacity and Generation

Gross Actual Generation – GAG (Column 9)
Enter the total wind turbine energy generated at the wind turbine for the sub-group (MWh). The Gross Actual Generation is the sum of all individual turbine meters before subtracting station service or auxiliary loads.

Net Actual Generation – NAG (Column 10)
Enter the net generation (MWh) recorded at the sub-group boundary. It is possible to have a negative net actual generation value if the group's station service or auxiliary loads are greater than total generation.

Net Maximum Capacity – NMC (Column 11)
Enter the actual generating capability (MW) at the sub-group boundary. This is equal to the installed capacity less any electrical losses such as transformation losses, line losses, and other losses due to transmission between the turbine and the revenue meter.

Available Turbine Hours (Active)

Period Turbine-Hours – PDTH (Column 12)
Enter the number of turbine-hours that the sub-group is in the active state. PDTH can vary in output reports (month, year, etc.) but for GADS-W reporting purposes, data is collected on the number of turbine-hours in a month.

Contact Turbine-Hours – CTH (Column 13)
Enter the number of turbine-hours the sub-group is synchronized to the system. It is the turbine-hours that the contactors are closed and generation is provided to the grid.

Reserve Shutdown Turbine-Hours – RSTH (Column 14)
Enter the sum of all turbine-hours for turbines that are off-line for economic reasons but available for service, although the sub-group is available to the system. Do not include RSTH in the same equations with CTH because this would double count turbine-hours.

Unavailable Turbine Hours (Active)

Forced Turbine-Hours – FTH (Column 15)
Forced Turbine-Hours is the sum of all turbine-hours that the sub-group is off-line due to forced events. FTH are all forced events where the Wind Turbine Generator (WTG) must be removed from service for repairs before the next Sunday at 23:59 (just before Sunday becomes Monday). **Note:** FTH includes OMC Forced Turbine-Hours (oFTH)

Maintenance Turbine-Hours – MTH (Column 16)
Maintenance Turbine-Hours is the sum of all turbine-hours that the sub-group is off-line due to a maintenance event. The turbine must be capable of running until the following week unless the outage occurs on the weekend the turbine must be capable of running through the following week. **Note:** MTH includes OMC Maintenance Turbine-Hours (oMTH)

Planned Turbine-Hours – PTH (Column 17)
Planned Turbine-Hours is the sum of all turbine-hours that the sub-group is off-line due to a planned event. A PTH event is scheduled well in advance and is of a predetermined duration and can occur several times a year. **Note:** PTH includes OMC Planned Turbine-Hours (oPTH)

Outside Management Control - OMC (Active)

OMC hours are hours that the subgroup is off-line due to events that are outside management control, such as abnormal weather or off-taker planned or unplanned downtime. See *Appendix H* for further details.

OMC Forced Turbine-Hours – oFTH (Column 18)
Subset of FTH, accounting for Forced Turbine-Hours that are due to events deemed to be outside of management control.

OMC Maintenance Turbine-Hours – oMTH (Column 19)
Subset of MTH, accounting for Maintenance Turbine-Hours that are due to events deemed to be outside of management control.

OMC Planned Turbine-Hours – oPTH (Column 20)
Subset of PTH, accounting for Planned Turbine-Hours that are due to events deemed to be outside of management control.

Other

Resource Unavailable Turbine-Hours – RUTH (Column 21)
The number of turbine hours that the turbines are available but not producing electricity for environmental conditions that are outside the operating specifications of the wind turbine. (i.e., low / high wind, low / high ambient temperature and column wind shutdown.)

Turbine Hours (Inactive)

Inactive Reserve Turbine-Hours – IRTH (Column 22)
Total number of turbine-hours in a period being reported that the sub-group is in the inactive reserve state.

Mothballed Turbine-Hours – MBTH (Column 23)
Total number of turbine-hours in a period being reported that the sub-group is in the mothballed state.

Retired Unit Turbine-Hours – RTH (Column 24)
Total number of turbine-hours in a period being reported that the sub-group is in the retired state.

Derated Turbine Hours

Equivalent Forced Derated Turbine Hours – EFDTH (Column 31) Optional
Total number of equivalent forced hours during one period (month)

Equivalent Maintenance Derated Turbine Hours – EMDTH (Column 32) Optional
Total number of equivalent maintenance hours during on period (month)

Equivalent Planned Derated Turbine Hours – EPDTH (Column 33) Optional
Total number of equivalent planned hours during one period (month)

OMC Equivalent Forced Derated Turbine Hours – oEFDTH (Column 34) Optional
Total number of OMC equivalent forced hours during one period (month)

OMC Equivalent Maintenance Derated Turbine Hours – oEMDTH (Column 35) Optional
Total number of OMC equivalent maintenance hours during one period (month)

OMC Equivalent Planned Derated Turbine Hours – oEPDTH (Column 36) Optional
Total number of OMC equivalent planned hours during one period (month).

Equivalent Reserve Shutdown Derated Turbine Hours – ERSDTH (Column 37) Optional
Total number of equivalent hours during one period (month). See definitions for a clear definition.

Delayed Turbine Hours

Forced Delay Turbine Hours – FXDTH (Column 38) Optional
Total number of delay hours during one period (month). See definitions for a clear definition.

Maintenance Delay Turbine Hours – MXDTH (Column 39) Optional
Total number of delay hours during one period (month). See definitions for a clear definition.

Planned Delay Turbine Hour –PXDTH (Column 40) Optional
Total number of delay hours during one period (month). See definitions for a clear definition.

Chapter 4 – Component Outage Reporting

The component outage reporting section is used to identify the general area or reason for WTG loss production as reported in the performance records at the sub-group level. To be accurate, the sum of the component turbine hours must equal the turbine hours shown in the performance records.

Component Record Layout (CSV Format)

Column	Field Name	Entry Type
1	Plant ID	Alpha-Numeric - 10
2	Group ID	Alpha-Numeric - 10
3	Sub-Group ID	Alpha-Numeric - 10
4	NERC Utility Code	Alpha-Numeric - 3
5	NERC Unit Code	Alpha-Numeric - 3
6	Report Period (month)	Numeric - 2
7	Report Year	Numeric - 4
8	System – Component Code	Numeric - 14
9	Forced Turbine Hours	Numeric - 8 + 2 decimals
10	Number of Forced Occurrences	Numeric - 14
11	Maintenance Turbine Hours	Numeric - 8 + 2 decimals
12	Number of Maintenance Occurrences	Numeric - 14
13	Planned Turbine Hours	Numeric - 8 + 2 decimals
14	Number of Planned Occurrences	Numeric - 14
15	Equivalent Forced Derated Hours (Optional)	Numeric - 8 + 2 decimals
16	Equivalent Maintenance Derated Hours (Optional)	Numeric - 8 + 2 decimals
17	Equivalent Planned Derated Hours (Optional)	Numeric - 8 + 2 decimals
18	Forced Delay Hours (Optional)	Numeric - 8 + 2 decimals
19	Maintenance Delay Hours (Optional)	Numeric - 8 + 2 decimals
20	Planned Delay Hours (Optional)	Numeric - 8 + 2 decimals

Plant ID (Column 1)
Enter the Plant ID as previously defined.

Group ID (Column 2)
Enter the Group ID as previously defined.

Sub-Group ID (Column 3)
Enter the sub-group ID as previously defined.

NERC Utility Code (Column 4)
Enter the three character alpha-numeric code NERC assigned to your utility. See *Appendix B*

NERC Unit Code (Column 5)
Enter the three character alpha-numeric code your utility assigned for the plant that you are reporting. This code distinguishes one plant from another in your utility. See *Appendix B*.

Report Period (Column 6)
Enter the two-digit month (MM) in which the event occurred. See *Appendix F* Table 8

Report Year (Column 7)
Enter the four-digit year (YYYY) in which the event occurred**.**

System – Component Code (Column 8)
Enter the system that was responsible for the outage. See *Appendix C* for a complete list of the system – component codes.

Component Turbine Hours and Occurrences

Forced Turbine Hours (Column 9)
Enter the total number of forced turbine hours (for the reporting sub-group) that are attributed to the system/component specified above during the period being reported.

Number of Forced Outage Occurrences (Column 10)
Enter the total number of forced outage events that are attributed to the system/component specified above during the period being reported.

Maintenance Turbine Hours (Column 11)
Enter the total number of maintenance turbine hours (for the reporting sub-group) that are attributed to the system/component specified above during the period being reported.

Number of Maintenance Outage Occurrences (Column 12)
Enter the total number of maintenance outage events that are attributed to the system/component specified above during the period being reported.

Planned Turbine Hours (Column 13)
Enter the total number of planned turbine hours (for the reporting sub-group) that are attributed to the system/component specified above during the period being reported.

Number of Planned Outage Occurrences (Column 14)
Enter the total number of planned outage events that are attributed to the system/component specified above during the period being reported.

Component Derates and Delay Turbine Hours

Equivalent Forced Derated Turbine Hours (Column 15) Optional
Enter the total number of equivalent forced outage hours that are attributed to the system/component specified above during the period being reported.

Equivalent Maintenance Derated Turbine Hours (Column 16) Optional
Enter the total number of equivalent maintenance outage hours that are attributed to the system/component specified above during the period being reported.

Equivalent Planned Derated Turbine Hours (Column 17) Optional
Enter the total number of equivalent planned outage hours that are attributed to the system/component specified above during the period being reported.

Forced Delay Turbine Hours (Column 18) Optional
Enter the total number of equivalent forced delay outage hours that are attributed to the system/component specified above during the period being reported.

Maintenance Delay Turbine Hours (Column 19) Optional
Enter the total number of equivalent maintenance delay hours that are attributed to the system/component specified above during the period being reported.

Planned Delay Turbine Hours (Column 20) Optional
Enter the total number of equivalent planned delay hours that are attributed to the system/component specified above during the period being reported.

Appendix A – GADS-W Data Release Guidelines

Introduction

NERC Wind Generating Availability Data System (GADS-W) contains information which can be broadly classified into five categories: plant, group, sub-group, component outage, and performance data.

The plant, group, and sub-group data is unrestricted and available to power generators, manufacturers and equipment suppliers, architect-engineers and consultants, industry organizations (EEI, EPRI, etc.), federal governmental organizations, and state and local governmental organizations.

To avoid the potential misuse of individual equipment data, the component outage and performance data are restricted and available only as specified in these guidelines.

Note: Per the guide lines below, only data to the level the participant is willing to provide will be returned on a data request. Example: A participant supports Wind GADS with performance data only; they will only receive performance data and not component data on a data request and data will only be released if the pool is large enough to prevent identification of individual O&M groups or plants.

Data Release Guidelines

Unless expressly permitted in the following sections, data by power generator, pool, Region, or specific unit will be provided only with the authorization of the appropriate power generator, pool, or Region. ("Power generators" are any owners or operators of electric generating units owned/operated by investor-owned, independent power producer (IPP), municipals, cooperative, federal, state, and all other groups of electric providers.) Special reports or studies which describe or rank power generators, pools, or regions by performance or other attributes – and in which specific units, power generators, pools, or regions are identifiable either by inclusion or exclusion – will be provided only with the authorization of the appropriate power generators, pools, or regions. Obtaining these approvals is the responsibility of the requester.

Appendix B – Utility and Unit Identification

Utility Identification Codes

NERC assigns each utility participating in the wind turbine generation database a unique identification code. This three character alpha-numeric code allows each system's data to be uniquely cataloged and filed in the database. Please look at the NERC GADS website or contact your Regional Entity for the latest list of utility codes.

Getting a New Utility Identification Code

NERC assigns each utility participating in the wind turbine generation database a unique identification code. This three character alpha-numeric code allows each system's data to be uniquely cataloged and filed in the database.

Plant Identification Codes

With assistance from the NERC staff or Regional Entity, each utility participating in the wind turbine generation database assigns their own unique identification codes to its plants. This unique three character alpha-numeric code allows each plant's data to be cataloged and filed in the database.

Appendix C – System-Component Codes

The following tables list available components for each system and the code to enter for each component:

System	Component	Entry
Balance of Plant	General	674
	Underground	650
	Metering and Relays	655
	Overhead Lines	652
	Pad Mount-Multiple WTG	651
	Preventative Maintenance	682
	SCADA	656
	Site Reactive Power Comp	654
	Substation	653
	Wind Park Control System	657
	Breakers	1037
	Main Substation Transformer	1038
	Switches	1039
	Wave Trap	1040
	CT / PT	1041
	Battery Systems	1042
	Site Communication	1043
	Fuses	1044
	Transmission (Gen Tie)	1077

System	Component	Entry
Brake	General	673
	High Speed Shaft Brake	617
	Mechanical Lock	618
	Brake Hydraulic System	1045

System	Component	Entry
Control System	General	672
	Cabinet Cooling/Heating	648
	Cold Weather Control	647
	Control Com Links Top and Bottom	644
	Low Voltage Control Wiring	638
	Processor	645
	Processor Cooling	646
	Reactive Power Control	640
	Sensors	642
	Software	643
	Voltage Regulation	639
	Wind Vane and Anemometer	649
	Hardware	1046
	Power Supply	1047
	Control Cabinet Filtration	1048
	Control Slip Rings	1049

System	Component	Entry
Drive Train	General	671
	Rotor Coupling	615
	Main Bearings	613
	Main Shaft	614
	Transmission Shaft	616

System	Component	Entry
Electrical	General	670
	Circuit Breakers and Switches	661
	Individual Turbine Transformers	662
	Power Compensation-WTG	660
	Power Converters	658
	Transmission Cables	659
	Current Transformers	1050
	Power Transformers	1051
	Converter Cooling	1052
	Power Supply	1053

System	Component	Entry
External	General (OMC)	681
	Catastrophe (OMC)	1034
	Economic (OMC)	1035
	Off-Taker Transmission & Distribution (OMC)	675
	Weather – Ice (OMC)	1036
	Weather – Lightning (OMC)	678
	Weather – Temperature (OMC)	676
	External Communication (OMC)	1057
	Weather – Turbulence (OMC)	1076
	Legal, Contractual or Environmental (OMC)	1079

System	Component	Entry
Gear Box	General	669
	Gear Box	608
	Gear Box Heating/Cooling	609
	Gear Box Oil System	610
	Gearbox Filtration	611
	Torque Arm System	612

System	Component	Entry
Generator/Exciter	General	668
	Exciter	634
	Generator	631
	Generator Bearings	632
	Generator Cooling Systems	636
	Generator Lube Oil Systems	633

	Generator Shaft	635
	Wiring to Gen Terminals	637
	RCC (Rotor Current Control)	641
	High Speed Coupling	1058
	Power Slip Rings	1059

System	Component	Entry
Hydraulic System	General	667
	Common Pump and Motor	627
	Filtering System	629
	Hoses, Reservoirs, Valves	630
	Hydraulic Accumulator	628
	Hydraulic Slip Ring	1060

System	Component	Entry
Pitch System	General	666
	Electrical	626
	Mechanical~~/Electrical~~	624
	Pitch Hydraulics	625
	Battery Backup	1061
	Pitch Controller	1062
	Pitch Motor	1063
	Pitch Gearbox	1064

System	Component	Entry
Rotor	General	665
	Aerodynamic Brake – Tip Brakes & Spoilers	602
	Blade Pitch Bearing	603
	Blades	600
	Deicing Systems	604
	Hub	601
	Lightning Protection	605
	Nose Cone	606
	Blade Coatings	1065
	Blade Attachments	1080

System	Component	Entry
Structures	General	664
	FAA Lighting	598
	Foundations	595
	MASS/Harmonic Damp	599
	Nacelle	593
	Nacelle Heating & Cooling	597
	Paint & Coatings	596
	Towers	594
	Ladders	1066
	Climb Assist / Elevator	1067
	Tower Filtration	1068

	Lighting	1069
	Hoist	1070

System	Component	Entry
Yaw System	General	663
	Slew Ring	620
	Yaw Dampening	622
	Yaw Gear	621
	Yaw Lubrication Systems	623
	Yaw Motors/Hydraulics	619

System	Component	Entry
Wind Turbine	General	1032
	Preventative Maintenance	1031
	Overall	1033

System	Component	Entry
Human Performance	General	1071
	Operator	1072
	Maintenance	1073
	Contractor	1074
	Procedure Error	1075

Appendix D – Terms and Definitions

General

Revenue Meter
The revenue meter is a device used to measure the electricity generated from a plant, group, or sub-group, depending on the plant configuration. The revenue meter accounts for the electricity sold to the customer and is normally owned by the off-taker.

Off-Taker
The entity that receives the power produced by the plant.

Utility
The principal organization that owns one or more plants.

Plant
The energy generating facility that consist of one or more groups or subgroups.

Group
Each plant consist of one or more groups. Groups are differentiated by the year they were commissioned.

Sub-Group
Each group consist of one or more sub-groups.

Capacity and Generation

Group Installed Capacity (GIC)
GIC is the sum of all the wind turbines' system nameplate rating capability within the group. GIC does not include spare wind turbines installed (AGIC below).

For example, suppose that you have two sub-groups within the group. The first sub-group is comprised of 20 Vestas V-47 machines rated at 0.66 MW each, and the second sub-group is comprised of 10 GE 1.5 machines rated at 1.5 MW each. The GIC would be (20 x 0.66 MW) + (10 x 1.5 MW), which would be 13.20 MW + 15.0 MW. This would give you a GIC of 28.2 MW.

Auxiliary Group Installed Capacity (AGIC)
AGIC is the installed capacity of any turbines that are not part of the GIC. These turbines must be available and connected to a sub-group, not in an inactive state, and their output can be temporarily added to the sub-group at a moment's notice in the event that another turbine becomes unavailable.

The purpose of auxiliary capacity is to allow producers to use WTGs that may have been phased out but are still in good working condition to improve their availability when turbines in the main generating group are in an unavailable state due to an outage.

Net Maximum Capacity (NMC)
NMC is the actual maximum generating capability at the revenue meter and is equal to the installed capacity less any electrical losses. These losses may include, but are not limited to, transformation losses, line losses, and other auxiliary losses between the turbine and revenue meter.

For example, if the GIC is 100 MW and the loss is 2% then the NMC can be calculated as 100 MW x (1 - 0.02). Our NMC is 98 MW.

Turbine Net Maximum Capacity (TNMC)
TNMC is the average Net Maximum Capacity of each turbine in the sub-group. It is calculated by dividing the NMC of the sub-group by the number of turbines in the sub-group. This value is used in equations so that turbine hours and turbine capacity may be used to arrive at a theoretical net max generation.

When multiple sub-groups are being pooled together, this value for the pooled set of turbines is equal to the sum of the capacities divided by the sum number of turbines.

Net Dependable Capacity (NDC)
NDC is the actual generating capability at the revenue meter less capacity losses. These losses may include, but are not limited to, losses from no wind, low wind, high wind, derated winds (less than rated capacity), or losses that occur outside the manufacturer's operating specifications (temperature, electrical & etc.). Another way of looking at NDC is the Capacity of the turbine at 100% availability while running within the manufacture's specification with the fuel source available (wind).

For example, if the NMC is 100 MW and the losses from all wind problems is 40% then the NDC can be calculated as 100 MW x (1 - 0.40). Our NDC would be 60 MW.

NDC may also be calculated as follows: [(Actual Generation) + (Turbine specific losses) + (reserve shutdown) + (Site outages such as off-taker problems + balance of plant, not wind related)] / (PH).

Net Available Capacity (NAC)
NAC is the actual generating capability at the revenue meter during the time of a planned, maintenance, forced, reserve, or spinning event.

For example, if the NMC is 120 MW and a maintenance event (feeder outage) reduces the capability by 5 MW, then the NAC is 115 MW.

Gross Actual Generation (GAG)
GAG is the total wind turbine energy going out of the Wind Turbine Group (MWh). GAG is the sum of all individual turbine meters before removing station service or auxiliary loads. GAG should be measured as close to the turbine's generator as possible so that generation is measured before any auxiliary use by the turbine.

Net Actual Generation (NAG)
NAG is the net generation (MWh) recorded at the revenue meter. It is possible to have a negative NAG value if the group's station service or auxiliary loads are greater than total generation.

Net Dependable Energy (NDE)
The Net Dependable Energy is defined as the potential energy based upon available resource.

Group or Sub-Group States

Active or Commercial State (Active)
Active state is the time from when the group is first declared commercially active until it moves to the inactive state shown below. A group is "declared commercial" when:

- The group is capable of reaching 50% of its generator nameplate MW Capacity (wind conditions not part of requirement) and
- Dispatch is notified that the group is capable of providing power (wind conditions not part of requirement).
- Power Purchase Agreement (PPA) or other distribution agreements satisfied.

Inactive State (IA)

Inactive State is called "Deactivated Shutdown" in IEEE 762 and is defined as "The state in which a group or individual WTG is unavailable for service for an extended period of time for reasons not related to the equipment." GADS interprets this to include the following.

- **Inactive Reserve (IR)** – IR is defined by IEEE 762 and GADS as "The State in which a group is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time, typically measured in days."

GADS added "after some repairs" and defines this statement to mean that some action may be needed to prepare the group for service because it had been sitting idle for a period of time and some equipment parts have deteriorated or need replacing before the group can be operated.

The group should be operable at the time the IR begins. *This does not include groups that may be idle because of a failure and dispatch did not call for operation*. A group that is not operable or is not capable of operation at a moment's notice should be on a forced, maintenance, or planned outage and remain on that outage until the proper repairs are completed and the group is able to operate. The group *must be* on RS (Reserve Shutdown) a minimum of 60 days before it can move to IR status.

- **Mothballed (MB)** – MB is defined by IEEE 762 and GADS as "The State in which a group or individual WTG is unavailable for service but can be brought back into service after some repairs with appropriate amount of notification, typically weeks or months."

GADS added "after some repairs" and defines this statement to mean that some action may be needed to prepare the group for service because it had been sitting idle for a period of time and some equipment parts may have deteriorated or need replacing before the group can be operated. The group may have also experienced a series of mechanical problems for which management may wish to wait for a period of time to determine if the group should be repaired or retired.

A group that is not operable or is not capable of operation at a moment's notice *must be* on a forced, maintenance, or planned outage and remain on that outage for at least 60 days before it can be moved to the MB state.

If repairs are being made on the group in order to restore the group to operating status before the 60-day period expires, then the outage must remain a forced, maintenance, or planned outage and not MB.

If group repairs for restoring the group to operation are made after the 60-day period then the first 60 days *must be* a forced, maintenance, or planned outage and the time after the 60 days, including the repair time on the group up to operation, shall be the MB event.

Turbine States and Hours Collection

Given the nature of wind generation, it would be a very rare occurrence for every turbine in a group or even a sub-group to be found in the same state. Therefore, due to the hours that turbines spend in various conditions, NERC GADS collects hours as turbine hours to enable NERC to calculate meaningful statistics. Using turbine-hours allows the operator to report hours simply by adding up the hours reported by each turbine.

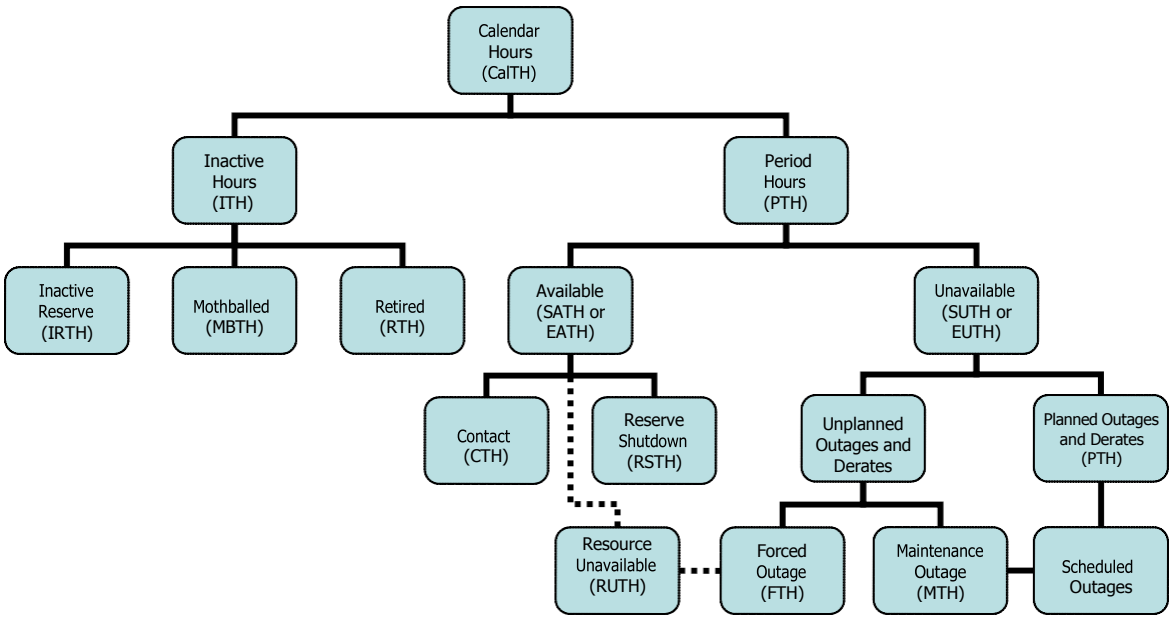


Figure D-1 Time Spent in Various Turbine Unit States

Calendar Hours (CalH)
Calendar Hours are the total number of hours within a given range of dates. These are typically shown as the number of hours in a month, quarter, or year.

Inactive Hours
Inactive Hours are the total number of calendar hours that a unit is in an inactive state (IA).

Period Hours (Active Hours) (PH)
Period Hours account for the number of calendar hours that the equipment is in an **active state**.

Turbine-Hours (TH)
Turbine-Hours are equal to the number of turbines in the group or sub-group times the number of Calendar Hours in the period. TH for any given condition for a given sub-group is equal to the total number of Calendar Hours that each wind turbine (WTG) in the sub-group spent in the given condition.

All of the following time/condition classifications are considered to be in turbine-hours. For example, the number of TH for a group of 12 WTG in January (with 744 hours in January) would be 12 x 744 or 8,928 TH. If one of those turbines were mothballed, the Period Turbine-Hours (PTH) would be 11 x 744 or 8,184 PTH with 744 Inactive Turbine-Hours.

Calendar Turbine-Hours (CalTH)
CalTH is equal to the sum of Period Turbine-Hours (PDTH) and Inactive Turbine-Hours (ITH). In most cases, PDTH and CalTH will be the same number.

Period Turbine-Hours (PDTH)
PDTH is the number of Turbine-Hours being reported that the sub-group is in the active state. PDTH can vary in output reports (month, year, etc.) but for GADS reporting purposes, data is collected on the number of Turbine-Hours in a month.

- In two instances, the PDTH may be smaller than the normal period hours for the given month: When the sub-group becomes commercially active, or
- When one or more turbines go into the Inactive Reserve, Mothballed, or Retired State.

The sum of Available Turbine-Hours and Unavailable Turbine-Hours must equal sub-group Period Turbine-Hours.

Inactive Turbine-Hours (ITH)
ITH is the number of turbine-hours in a period being reported that the sub-group is in the inactive state.

Contact Turbine-Hours (CTH)
CTH is the number of turbine-hours the sub-group is synchronized to the system. It is the turbine-hours that the contactors are closed and generation is provided to the grid.

Reserve Shutdown Turbine-Hours (RSTH)
RSTH is the sum of all turbine-hours that the sub-group is available to the system for economic reasons. Do not include RSTH with the same equations with CTH (this would result in double counting total turbine-hours). IEEE 762 and the T/H NERC DRI define RSTH as a turbine shutdown due to economic reasons. To qualify the following must be true:

1. The turbine must be in an active state.
2. The turbine must be available not in an outage state.
3. The turbine must not be in eminent danger of failure.

Note: Disabling a turbine (such as removing a processor card) immediately puts the turbine in an outage state and makes it no longer available.

Economic for purposes, Reserve Shutdown is defined as demand or market curtailments.

Examples of RSTH are negative energy pricing, contracts, agreements,

Resource Unavailable Turbine-Hours (RUTH)
RUTH is the number of turbine-hours the sub-group is not producing electricity due to the wind being too low or too high or due to reasons outside the manufacturer's operating specifications. RUTH is classified as Available Turbine-Hours for equipment calculations and Unavailable Turbine-Hours for site calculations. See *Figures D-2, D3and D-4* below.

Forced Turbine-Hours (FTH)
FTH is the sum of all turbine-hours that the sub-group is off-line due to forced events. FTH are all forced events where the WTG must be removed from service for repairs *before* the next Sunday at 23:59 (just before Sunday becomes Monday). Examples can be found in *Appendix H*.

OMC Forced Turbine-Hours (oFTH)
oFTH is a sub-set of FTH that equals any forced turbine-hours that were due to causes deemed to be outside of management control. For more information on OMC, refer to *Appendix G*. Examples can be found in *Appendix H*.

Maintenance Turbine-Hour (MTH)
MTH is the sum of all turbine-hours that the sub-group is off-line due to a Maintenance Event.

A maintenance event is an event that can be deferred beyond the end of the next weekend (Sunday at 2400), but requires that a wind turbine be removed from service, another outage state, or Reserve Shutdown state before the next Planned event. Characteristically, a maintenance event can occur at any time during the year, has a flexible start date, may or may not have a predetermined duration, and is usually much shorter than a Planned Event.

If an event occurs before Friday at 2400, the above definition applies. If the event occurs after Friday at 2400 and before Sunday at 2400, the Maintenance event will only apply if the event can be delayed past the next weekend, not the current one. If the event cannot be deferred, it is a Forced Event. Examples can be found in *Appendix H*.

OMC Maintenance Turbine-Hour (oMTH)
OMTH is a sub-set of MTH that equals any maintenance Turbine-Hours that were due to causes deemed to be outside of management control (OMC). For more information on OMC, refer to *Appendix G*. Examples can be found in *Appendix H*.

Planned Turbine-Hour (PTH)
PTH is the sum of all Turbine-Hours that the sub-group is off-line due to a planned event. A Planned Event is scheduled well in advance and is of predetermined duration and can occur several times a year. Examples can be found in *Appendix H*.

OMC Planned Turbine-Hour (oPTH)
oPTH is a sub-set of PTH that equals any planned Turbine-Hours that were due to causes deemed to be outside of management control. For more information on OMC, refer to *Appendix G*.

Site Available Turbine-Hours (SATH)
SAH is the Period Turbine-Hours (PDTH) minus the Resource Unavailable Turbine-Hours (RUTH).

Equipment Available Turbine-Hours (EATH)
EATH is the sum of the Contact Turbine-Hours (CTH) and Resource Unavailable Turbine-Hours (RUTH).

Site Unavailable Turbine-Hours (SUTH)
SUTH is the sum of Planned Turbine-Hours (PTH), Forced Turbine-Hours (FTH), Maintenance Turbine- Hours (MTH) and Resource Unavailable Turbine-Hours (RUTH).

Equipment Unavailable Turbine-Hours (EUTH)
EUTH is the sum of Planned Turbine-Hours (PTH), Forced Turbine-Hours (FTH), and Maintenance Turbine- Hours (MTH).

Equivalent Hours
Equivalent hours occur when turbine power is reduced from the installed capacity. The equivalent hours can be calculated several ways:

1. An individual turbine's power is reduced. Example – a 1.5MW turbine is limited to 1.0MW of 10 hrs. This is a 33.3% reduction in power so the equivalent outage hours are 10/3 – 3.33hrs.
2. A group of turbines maybe limited in their output. Example – a 100MW plant is limited to 50MW. This is a 50% restriction so 50% of the hours during the period are equivalent outage hours. 10 turbines for 8 hours = 80 hours total times 50% equals 40 equivalent outage hours.

Note: Equivalent hours are only used in the numerator of equations as the hours are already counted as contactor hours in the denominator. Turbine output is reduced but the unit is still on line.

Equivalent Forced Derated Turbine Hours (EFDTH)
EFDTH are the equivalent forced turbine hours when turbine output is reduced for forced issues.

Equivalent Maintenance Derated Turbine Hours (EMDTH)
EMDTH are the equivalent maintenance turbine hours when the turbine output is reduced for maintenance turbine hours, EMDTH must meet the requirements for a maintenance outage. The turbine must be capable of running until the following week unless the outage occurs on the weekend the turbine must be capable of running through the following week.

Equivalent Planned Derated Turbine Hours (EPDTH)
EPDTH are the equivalent planned turbine hours when turbine output is reduced for a planned issue.

OMC Equivalent Forced Derated Turbine Hours (oEFDTH)
oEFDTH are OMC equivalent forced turbine hours when turbine output is reduced for OMC forced issues.

OMC Equivalent Maintenance Derated Turbine Hours (oEMDTH)
oEMDTH are OMC equivalent maintenance hours when turbine output is reduced for OMC maintenance issues.

OMC Equivalent Planned Derated Turbine Hours (oEPDTH)
oEPDTH are OMC equivalent planned hours when turbine output is reduced for OMC planned issues.

Equivalent Reserve Shutdown Derated Turbine Hours (ERSDTH) – Optional
ERSDTH are the equivalent reserve shutdown hours when turbine output is reduced for economic reasons.

Reduced output for economic reasons is a real issue with wind energy and can have a significant impact on income. Different SCADA systems implement economic shutdowns using one of two methods:

1. Complete shutdown of turbines to meet the RS requirement. This is already accounted for in the RS hours.
2. The second method reduces or limits the output of a plant. Turbine output is not reduced to zero but is derated as a percent of total capacity. These equivalent hours are usually equal to or greater than RS hours.

This optional metric is not used in any equation listed in this document but when added to RS gives the plant a better understanding of the impact due to economic shutdowns.

Delays
Due to the locations and environments wind turbines reside in, repairs and maintenance events are often delayed. These delays can add significant time to these events, and tracking them helps NERC understand their impact. The delay hours are not used in any of the listed equations. Individual delay types are not tracked at this time but can take many forms:

1. Environment – Ice on towers, blades and nacelles. High winds, snow and flooding.
2. Access – The inability to get to the turbines and or the site (people / equipment)
3. Equipment – Availability and or permitting.
4. Labor – Limited availability of labor or inadequate labor.

5. Material – High failure rates deplete inventory, long lead times for repairs or parts availability.

Force Delay Turbine Hours (FDXTH) Optional
FDTH are the delay hours that extend repairs beyond their expected repair period.

Maintenance Delay Turbine hour (MDXTH) Optional
MDTH are the delay hours that extend repairs beyond their expected maintenance period.

Planned Delay Turbine Hours (PDXTH) Optional
PDTH are the delay hours that extend repairs beyond their expected planned period.

Priority of Outage Reporting
In some instances, there may be more than one event occurring at the same time. In such cases, the turbine remains in its current state until it is cleared and then moves to the next applicable state.

1. Contact Turbine-Hours
2. Forced Turbine-Hours
3. Maintenance Turbine-Hours
4. Planned Turbine-Hours
5. Reserve Shutdown Turbine-Hours
6. Resource Unavailable Turbine-Hours

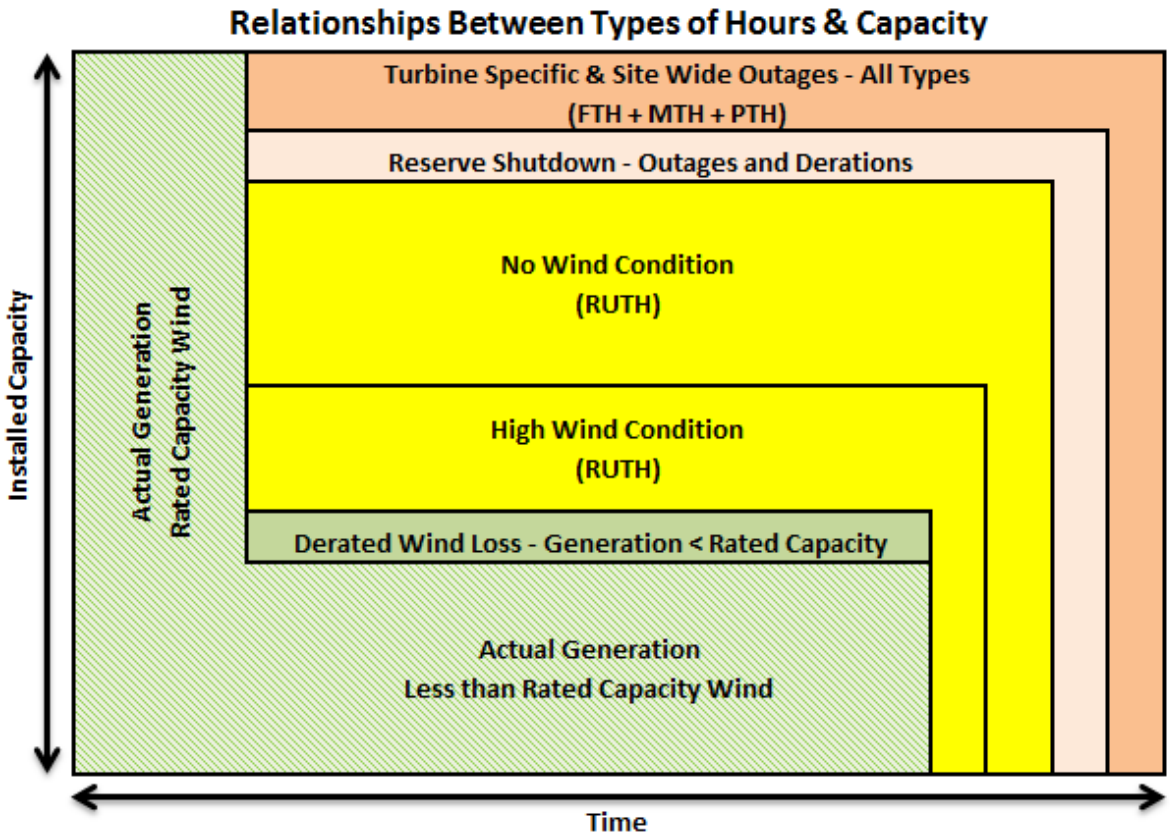


Figure D-2

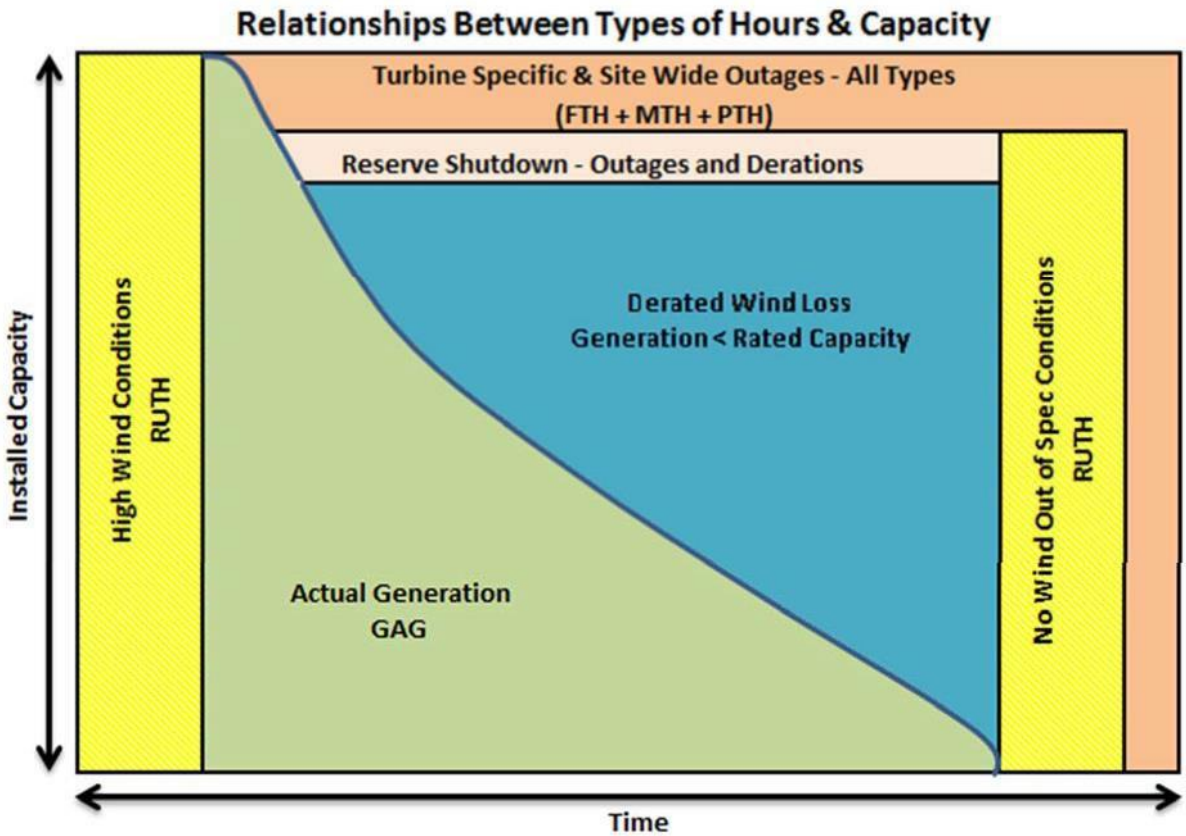

Relationships Between Types of Hours & Capacity
Turbine Specific & Site Wide Outages - All Types
(FTH + MTH + PTH)
Reserve Shutdown - Outages and Derations
Derated Wind Loss
Generation < Rated Capacity
Actual Generation
GAG
High Wind Conditions
RUTH
No Wind Out of Spec Conditions
RUTH
Installed Capacity
Time

Figure D-3

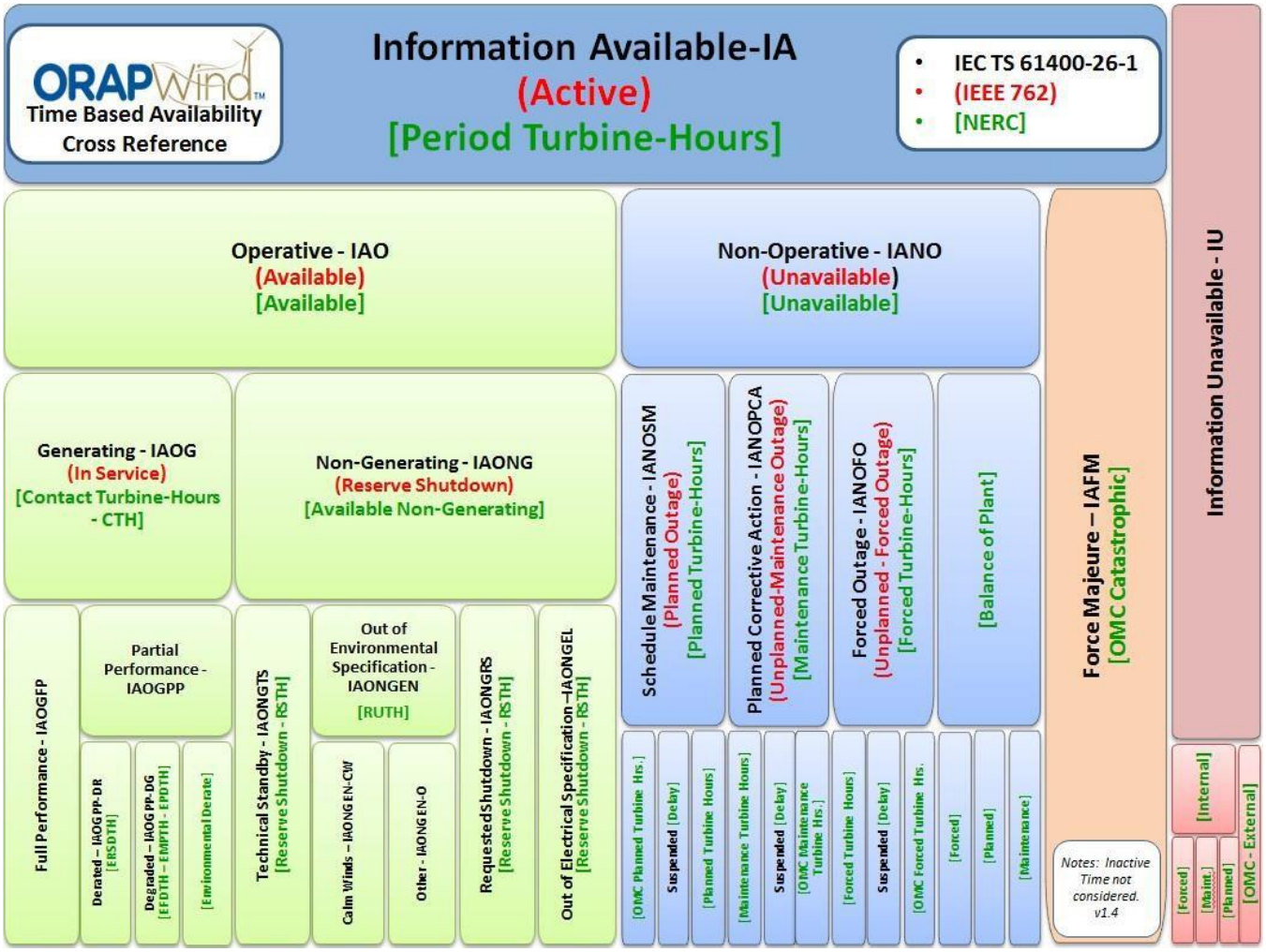


Figure D-4 Cross Reference

Appendix E – Equations

Four different sets of performance equations are listed. A description of these sections is below.

1. **Resource and Equipment Calculations** – These equations calculate the individual resource and equipment performance by turbine sub-group(s) that have similar turbine capacities. These equations also include OMC hours.
2. **Pooled Resource and Equipment Calculations** – These equations pool the resource and equipment performance of sub-groups into collections of sub-groups, groups, or plants. These equations also include OMC hours. These equations are not weighted and should only be used for pooling data with turbines of the same turbine capacity.
3. **Resource and Equipment Calculations without OMC Hours** – These equations calculate the individual resource and equipment performance by turbine sub-group(s) that have the same, or very similar, turbine capacities. These equations do not include OMC hours.
4. **Multi-Resource and -Equipment Calculations without OMC Hours** – These equations pool the resource and equipment performance of sub-groups into collections of sub-groups, groups, or plants. These equations do not include OMC hours. These equations are not weighted and should only be used for pooling data with turbines of the same turbine capacity.

In most cases, "resource" performance factors and rates take into account all outages and hours. These include, but are not limited to, outages from resource (wind) unavailability, equipment failures, off-taker events, weather, and any other non-equipment outages. Resource equations are primarily used by resource planners integrating wind energy into the bulk power supply.

Equipment performance factors and rates take into account Calendar Hours, Period Hours, and all outages pertaining to equipment that fall within and outside of management control for a given study. Equipment performance equations are used by plant managers to monitor performance behind the plant boundary.

SECTION 1:

Resource and Equipment Calculations (for sub-groups)

1.A. Resource Performance Factors

These are performance rates and factors that highlight the effect of the resource and are primarily used by planners or from a system view. In order to do that, Resource Unavailable Turbine-Hours (RUTH) are treated as forced outage hours. This defines the ability of the technology to deliver power to the bulk power system

1.A.1. Resource Equivalent Availability Factor (REAF)
% of period that the plant was available.

$$REAF = \frac{[PDTH - (FTH + MTH + PTH + EFDTH + EMDTH + EPDTH + RUTH)]}{PDTH} \times 100$$
$$\approx (100 - REUF)$$

1.A.2. Resource Equivalent Unavailability Factor (REUF)

% of period that the plant was unavailable.

$$REUF = \frac{(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH + RUTH)}{PDTH} \times 100$$
$$\approx (100 - REAF)$$

1.A.3. Resource Equivalent Planned Outage Factor (REPOF)

% of period that the plant was in planned downtime.

$$REPOF = \frac{(PTH + EPDTH)}{PDTH} \times 100$$

1.A.4. Resource Equivalent Maintenance Outage Factor (REMOF)

% of period that the plant was in maintenance downtime.

$$REMOF = \frac{(MTH + EMDTH)}{PDTH} \times 100$$

1.A.5. Resource Equivalent Forced Outage Factor (REFOF)

% of period that the plant was forced off line. Including low and high winds.

$$REFOF = \frac{(FTH + EFDTH + RUTH)}{PDTH} \times 100$$

1.A.6. Resource Equivalent Unplanned Outage Factor (REUOF)

% of period that the plant was unavailable due to forced and maintenance downtime. For generation resource planning.

$$REUOF = \frac{(FTH + MTH + EFDTH + EMDTH + RUTH)}{PDTH} \times 100$$

1.A.7. Resource Equivalent Scheduled Outage Factor (RESOF)

% of period that the plant was unavailable due to maintenance and planned downtime.

$$RESOF = \frac{(MTH + PTH + EMDTH + EPDTH)}{PDTH} \times 100$$

1.A.8. Resource Generating Factor (RGF)
% of period that the plant was online and in a generating state.

$$RGF = \frac{CTH}{PDTH} \times 100$$

1.A.9. Resource Net Capacity Factor (RNCF)
% of actual plant generation.

$$RNCF = \frac{NAG}{(PDTH \times TNMC)} \times 100$$

1.A.10. Net Output Factor (NOF)
% of actual plant loading when on-line.

$$NOF = \frac{NAG}{(CTH \times TNMC)} \times 100$$

1.A. Resource Performance Rates

1.A.11. Resource Equivalent Planned Outage Rate (REPOR)
Probability of planned plant downtime when needed for load.

$$REPOR = \frac{(PTH + EPDTH)}{(CTH + PTH)} \times 100$$

1.A.12. Resource Equivalent Maintenance Outage Rate (REMOR)
Probability of maintenance plant downtime when needed for load.

$$REMOR = \frac{(MTH + EMDTH)}{(CTH + MTH)} \times 100$$

1.A.13. Resource Equivalent Forced Outage Rate (REFOR)
Probability of forced plant downtime when needed for load.

$$REFOR = \frac{(FTH + EFDTH + RUTH)}{(CTH + FTH + RUTH)} \times 100$$

1.A.14. Resource Equivalent Unplanned Outage Rate (REUOR)
Probability of forced or maintenance plant downtime (including high and low winds) when needed for load.

$$REUOR = \frac{(FTH + MTH + EFDTH + EMDTH + RUTH)}{(CTH + FTH + MTH + RUTH)} \times 100$$

1.A.15. Resource Equivalent Scheduled Outage Rate (RESOR)
Probability of maintenance or planned plant downtime when needed for load.

$$RESOR = \frac{(MTH + PTH + EMDTH + EPDTH)}{(CTH + MTH + PTH)} \times 100$$

1.B. Equipment Performance Factors

These are performance rates and factors that highlight the effect of the equipment and reduce the effect of the resource availability, plant view. In order to do that, Resource Unavailable Turbine-Hours (RUTH) are considered available non-generating hours rather than forced outage hours. This gives the maximum number of hours the equipment could have operated normally.

1.B.1. Equipment Equivalent Availability Factor (EEAF)
% of period that the WTG equipment was available.

$$EEAF = \frac{[PDTH - (FTH + MTH + PTH + EFDTH + EMDTH + EPDTH)]}{PDTH} \times 100$$

$$\approx (100 - EEUF)$$

1.B.2. Equipment Equivalent Unavailability Factor (EEUF)
% of period that the WTG equipment was unavailable.

$$EEUF = \frac{(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH)}{PDTH} \times 100$$

$$\approx (100 - EEAF)$$

1.B.3. Equipment Equivalent Planned Outage Factor (EEPOF)
% of period that the WTG equipment was in planned downtime.

$$EEPOF = \frac{(PTH + EPDTH)}{PDTH} \times 100$$

1.B.4. Equipment Equivalent Maintenance Outage Factor (EEMOF)
% of period that the WTG equipment was in maintenance downtime.

$$EEMOF = \frac{(MTH + EMDTH)}{PDTH} \times 100$$

1.B.5. Equipment Equivalent Forced Outage Factor (EEFOF)
% of period that the WTG equipment was forced off line. Including low and high winds.

$$EEFOF = \frac{(FTH + EFDTH)}{PDTH} \times 100$$

1.B.6. Equipment Equivalent Unplanned Outage Factor (EEUOF)
% of period that the WTG equipment was unavailable due to forced and maintenance downtime. For generation resource planning.

$$EEUOF = \frac{(FTH + MTH + EFDTH + EMDTH)}{PDTH} \times 100$$

1.B.7. Equipment Equivalent Scheduled Outage Factor (EESOF)
% of period that the WTG equipment was unavailable due to maintenance and planned downtime.

$$EESOF = \frac{(MTH + PTH + EMDTH + EPDTH)}{PDTH} \times 100$$

1.B.8. Equipment Generating Factor (EGF)
% of period that the WTG equipment was online and in a generating state.

$$EGF = \frac{CTH}{(PDTH - RUTH)} \times 100$$

1.B.9. Equipment Net Capacity Factor (ENCF)
% of actual WTG equipment generation while on line.

$$ENCF = \frac{NAG}{((PDTH - RUTH) \times TNMC)} \times 100$$

1.B Equipment Performance Rates

1.B.10. Equipment Equivalent Planned Outage Rate (EEPOR)
Probability of planned WTG equipment downtime when needed for load.

$$EEPOR = \frac{(PTH + EPDTH)}{(CTH + PTH + RUTH)} \times 100$$

1.B.11. Equipment Equivalent Maintenance Outage Rate (EEMOR)
Probability of maintenance WTG equipment downtime when needed for load.

$$EEMOR = \frac{(MTH + EMDTH)}{(CTH + MTH + RUTH)} \times 100$$

1.B.12. Equipment Equivalent Forced Outage Rate (EEFOR)
Probability of forced WTG equipment downtime when needed for load.

$$EEFOR = \frac{(FTH + EFDTH)}{(CTH + FTH + RUTH)} \times 100$$

1.B.13. Equipment Equivalent Unplanned Outage Rate (EEUOR)
Probability of forced or maintenance WTG equipment downtime (including high or low winds) when needed for load.

$$EEUOR = \frac{(FTH + MTH + EFDTH + EMDTH)}{(CTH + FTH + MTH + RUTH)} \times 100$$

1.B.14. Equipment Equivalent Scheduled Outage Rate (EESOR)
Probability of maintenance or planned WTG equipment downtime when needed for load.

$$EESOR = \frac{(MTH + PTH + EMDTH + EPDTH)}{(CTH + MTH + PTH + RUTH)} \times 100$$

SECTION 2:

Pooled Resource and Equipment Calculations

Pooling refers to the method of grouping units together into cumulative indexes. For instance, a cumulative, or aggregate, index for a plant or fleet may be made by pooling the data from all related sub-groups.

This section provides un-weighted pooling of turbine-hours which gives the same weight to each unit in the group regardless of size. Sums, ∑(), in this section refer to the summation for each sub-group.

2.A Pooled Resource Performance Factors

2.A.1. Pooled Resource Equivalent Availability Factor (PREAF)
% of period that the plant was available.

$$PREAF = \frac{\sum\left[PDTH - \left(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH + RUTH\right)\right]}{\sum PDTH} \times 100$$

$$\approx \left(100 - PREUF\right)$$

2.A.2. Pooled Resource Equivalent Unavailability Factor (PREUF)
% of period that the plant was unavailable.

$$PREUF = \frac{\sum\left(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH + RUTH\right)}{\sum PDTH} \times 100$$

$$\approx \left(100 - PREAF\right)$$

2.A.3. Pooled Resource Equivalent Planned Outage Factor (PREPOF)
% of period that the plant was in planned downtime.

$$PREPOF = \frac{\sum(PTH + EPDTH)}{\sum PDTH} \times 100$$

2.A.4. Pooled Resource Equivalent Maintenance Outage Factor (PREMOF)
% of period that the plant was in maintenance downtime.

$$PREMOF = \frac{\sum(MTH + EMDTH)}{\sum PDTH} \times 100$$

2.A.5. Pooled Resource Equivalent Forced Outage Factor (PREFOF)
% of period that the plant was forced off line. Including low and high winds.

$$PREFOF = \frac{\sum(FTH + EFDTH + RUTH)}{\sum PDTH} \times 100$$

2.A.6. Pooled Resource Equivalent Unplanned Outage Factor (PREUOF)
% of period that the plant was unavailable due to forced and maintenance downtime. For generation resource planning.

$$PREOUF = \frac{\sum(FTH + MTH + EFDTH + EMDTH + RUTH)}{\sum PDTH} \times 100$$

2.A.7. Pooled Resource Equivalent Scheduled Outage Factor (PRESOF)
% of period that the plant was unavailable due to maintenance and planned downtime.

$$PRESOF = \frac{\sum(MTH + PTH + EMDTH + EPDTH)}{\sum PDTH} \times 100$$

2.A.8. Pooled Resource Generating Factor (PRGF)
% of period that the plant was online and in a generating state.

$$PRGF = \frac{\sum CTH}{\sum PDTH} \times 100$$

2.A.9. Pooled Resource Net Capacity Factor (PRNCF)
% of actual plant generation.

$$PRNCF = \frac{\sum NAG}{\sum(PDTH \times TNMC)} \times 100$$

2.A.10. Pooled Net Output Factor (PNOF)
% of actual plant loading when on-line.

$$PNOF = \frac{\sum NAG}{\sum(CTH \times TNMC)} \times 100$$

2.A Pooled Resource Performance Rates

2.A.11. Pooled Resource Equivalent Planned Outage Rate (PREPOR)
Probability of planned plant downtime when needed for load.

$$PREPOR = \frac{\sum(PTH + EPDTH)}{\sum(CTH + PTH)} \times 100$$

2.A.12. Pooled Resource Equivalent Maintenance Outage Rate (PREMOR)
Probability of maintenance plant downtime when needed for load.

$$PREMOR = \frac{\sum(MTH + EMDTH)}{\sum(CTH + MTH)} \times 100$$

2.A.13. Pooled Resource Equivalent Forced Outage Rate (PREFOR)
Probability of forced plant downtime when needed for load.

$$PREFOR = \frac{\sum(FTH + EFDTH + RUTH)}{\sum(CTH + FTH + RUTH)} \times 100$$

2.A.14. Pooled Resource Equivalent Unplanned Outage Rate (PREUOR)
Probability of forced or maintenance plant downtime (including high and low winds) when needed for load.

$$PREUOR = \frac{\sum(FTH + MTH + EFDTH + EMDTH + RUTH)}{\sum(CTH + FTH + MTH + RUTH)} \times 100$$

2.A.15. Pooled Resource Equivalent Scheduled Outage Rate (PRESOR)
Probability of maintenance or planned plant downtime when needed for load.

$$PRESOR = \frac{\sum(MTH + PTH + EMDTH + EPDTH)}{\sum(CTH + MTH + PTH)} \times 100$$

2.B Pooled Equipment Performance Factors

2.B.1. Pooled Equipment Equivalent Availability Factor (PEEAF)
% of period that the WTG equipment was available.

$$PEEAF = \frac{\sum\left[PDTH - \left(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH\right)\right]}{\sum PDTH} \times 100$$

$$\approx (100 - PEEUF)$$

2.B.2. Pooled Equipment Equivalent Unavailability Factor (PEEUF)
% of period that the WTG equipment was unavailable.

$$PEEUF = \frac{\sum\left(FTH + MTH + PTH + EFDTH + EMDTH + EPDTH\right)}{\sum PDTH} \times 100$$

$$\approx (100 - PEEAF)$$

2.B.3. Pooled Equipment Equivalent Planned Outage Factor (PEEPOF)
% of period that the WTG equipment was in planned downtime.

$$PEEPOF = \frac{\sum(PTH + EPDTH)}{\sum PDTH} \times 100$$

2.B.4. Pooled Equipment Equivalent Maintenance Outage Factor (PEEMOF)
% of period that the WTG equipment was in maintenance downtime.

$$PEEMOF = \frac{\sum(MTH + EMDTH)}{\sum PDTH} \times 100$$

2.B.5. Pooled Equipment Equivalent Forced Outage Factor (PEEFOF)
% of period that the WTG equipment was forced off line. Including low and high winds.

$$PEEFOF = \frac{\sum(FTH + EFDTH)}{\sum PDTH} \times 100$$

2.B.6. Pooled Equipment Equivalent Unplanned Outage Factor (PEEUOF)
% of period that the WTG equipment was unavailable due to forced and maintenance downtime. For generation resource planning.

$$PEEUOF = \frac{\sum(FTH + MTH + EFDTH + EMDTH)}{\sum PDTH} \times 100$$

2.B.7. Pooled Equipment Equivalent Scheduled Outage Factor (PEESOF)
% of period that the WTG equipment was unavailable due to maintenance and planned downtime.

$$PEESOF = \frac{\sum(MTH + PTH + EMDTH + EPDTH)}{\sum PDTH} \times 100$$

2.B.8. Pooled Equipment Generating Factor (PEGF)
% of period that the WTG equipment was online and in a generating state.

$$PEGF = \frac{\sum CTH}{\sum(PDTH - RUTH)} \times 100$$

2.B.9. Pooled Equipment Net Capacity Factor (PENCF)
% of actual WTG equipment generation.

$$PENCF = \frac{\sum NAG}{\sum((PDTH - RUTH) \times TNMC)} \times 100$$

2.B Pooled Equipment Performance Rates

2.B.10. Pooled Equipment Equivalent Planned Outage Rate (PEEPOR)
Probability of planned WTG equipment downtime when needed for load.

$$PEEPOR = \frac{\sum(PTH + EPDTH)}{\sum(CTH + PTH + RUTH)} \times 100$$

2.B.11. Pooled Equipment Equivalent Maintenance Outage Rate (PEEMOR)
Probability of maintenance WTG equipment downtime when needed for load.

$$PEEMOR = \frac{\sum(MTH + EMDTH)}{\sum(CTH + MTH + RUTH)} \times 100$$

2.B.12. Pooled Equipment Equivalent Forced Outage Rate (PEEFOR)
Probability of forced WTG equipment downtime when needed for load.

$$PEEFOR = \frac{\sum(FTH + EFDTH)}{\sum(CTH + FTH + RUTH)} \times 100$$

2.B.13. Pooled Equipment Equivalent Unplanned Outage Rate (PEEUOR)
Probability of forced or maintenance WTG equipment downtime (including high or low winds) when needed for load.

$$PEEUOR = \frac{\sum(FTH + MTH + EFDTH + EMDTH)}{\sum(CTH + FTH + MTH + RUTH)} \times 100$$

2.B.14. Pooled Equipment Equivalent Scheduled Outage Rate (PEESOR)
Probability of maintenance or planned WTG equipment downtime when needed for load.

$$PEESOR = \frac{\sum(MTH + PTH + EMDTH + EPDTH)}{\sum(CTH + MTH + PTH + RUTH)} \times 100$$

SECTION 3:

Resource and Equipment Calculations without OMC Hours

3.A Resource Performance Factors (including resources without OMC hours)

These are performance rates and factors that highlight the effect of the resource and are primarily used by planners, system view. In order to do that, Resource Unavailable Turbine-Hours (RUTH) are treated as forced outage hours. This defines the ability of the technology to deliver power to the bulk power system. These equations also remove the effect of OMC on system performance.

3.A.1. OMC Resource Equivalent Availability Factor (XREAF)
% of period that the plant was available.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$XREAF = \frac{[PDTH - (OutageHrs + DeratedHrs + RUTH) + (OMCHrs + DeratedOMCHrs)]}{PDTH} \times 100$$
$$\approx (100 - XREUF)$$

3.A.2. OMC Resource Equivalent Unavailability Factor (XREUF)
% of period that the plant was unavailable.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$XREUF = \frac{[(OutageHrs + DeratedHrs + RUTH) - (OMCHrs + DeratedOMCHrs)]}{PDTH} \times 100$$
$$\approx (100 - XREAF)$$

3.A.3. OMC Resource Equivalent Planned Outage Factor (XREPOF)
% of period that the plant was in planned downtime.

$$XREPOF = \frac{((PTH + EPDTH) - (oPTH + oEPDTH))}{PDTH} \times 100$$

3.A.4. OMC Resource Equivalent Maintenance Outage Factor (XREMOF)
% of period that the plant was in maintenance downtime.

$$XREMOF = \frac{((MTH + EMDTH) - (oMTH + oEMDTH))}{PDTH} \times 100$$

3.A.5. OMC Resource Equivalent Forced Outage Factor (XREFOF)
% of period that the plant was forced off line. Including low and high wind.

$$XREFOF = \frac{[((FTH + EFDTH) - (oFTH + oEFDTH)) + RUTH]}{PDTH} \times 100$$

3.A.6. OMC Resource Equivalent Unplanned Outage Factor (XREUOF)
% of period that the plant was unavailable due to forced and maintenance downtime. For generation resource planning.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$XREOUF = \frac{[(UOHrs + UDerateOHrs + RUTH) - (UOMCHrs + UOMCDerateHrs)]}{PDTH} \times 100$$

3.A.7. OMC Resource Equivalent Scheduled Outage Factor (XRESOF)
% of period that the plant was unavailable due to maintenance and planned downtime.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$XRESOF = \frac{[(SOHrs + SODerateHrs) - (SOMCHrs + SOMCDerateHrs)]}{PDTH} \times 100$$

3.A Resource Performance Rates (including resources without OMC hours)

3.A.8. OMC Resource Equivalent Planned Outage Rate (XREPOR)
Probability of planned plant downtime when needed for load.

$$XREPOR = \frac{((PTH + EPDTH) - (oPTH + oEPDTH))}{[CTH + (PTH - oPTH)]} \times 100$$

3.A.9. OMC Resource Equivalent Maintenance Outage Rate (XREMOR)
Probability of maintenance plant downtime when needed for load.

$$XREMOR = \frac{((MTH + EMDTH) - (oMTH + oEMDTH))}{[CTH + (MTH - oMTH)]} \times 100$$

3.A.10. OMC Resource Equivalent Forced Outage Rate (XREFOR)
Probability of forced plant downtime when needed for load.

$$XREFOR = \frac{\left[\left((FTH + EFDTH) - (oFTH + oEFDTH)\right) + RUTH\right]}{\left[CTH + \left(FTH - oFTH\right) + RUTH\right]} \times 100$$

3.A.11. OMC Resource Equivalent Unplanned Outage Rate (XREUOR)
Probability of forced or maintenance plant downtime (including high or low winds) when needed for load.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$XREUOR = \frac{\left[\left(UOHrs + UDerateOHrs + RUTH\right) - \left(UOMCHrs + UOMCDerateHrs\right)\right]}{CTH + \left[\left(UOHrs + RUTH\right) - UOMCHrs\right]} \times 100$$

3.A.12. OMC Resource Equivalent Scheduled Outage Rate (XRESOR)
Probability of maintenance or planned plant downtime when needed for load.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$XRESOR = \frac{\left[\left(SOHrs + SODerateHrs\right) - \left(SOMCHrs + SOMCDerateHrs\right)\right]}{\left[\left(CTH + SOHrs\right) - \left(SOMCHrs\right)\right]} \times 100$$

3.B Equipment Performance Factors (without OMC hours)

These are performance rates and factors that highlight the effect of the equipment and reduce the effect of the resource availability, plant view. In order to do that, Resource Unavailable Turbine-Hours (RUTH) are considered available non-generating hours rather than forced outage hours. This gives the maximum number of hours the equipment could have operated normally. The equations also remove OMC events from the calculations. This leaves a clean plant view.

3.B.1. OMC Equipment Equivalent Availability Factor (XEEAF)
% of period that the WTG equipment was available.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$XEEAF = \frac{[PDTH - (OutageHrs + DeratedHrs) + (OMCHrs + DeratedOMCHrs)]}{PDTH} \times 100$$
$$\approx (100 - XEEUF)$$

3.B.2. OMC Equipment Equivalent Unavailability Factor (XEEUF)
% of period that the WTG equipment was unavailable.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$XEEUF = \frac{[(OutageHrs + DeratedHrs) - (OMCHrs + DeratedOMCHrs)]}{PDTH} \times 100$$
$$\approx (100 - XEEAF)$$

3.B.3. OMC Equipment Equivalent Planned Outage Factor (XEEPOF)
% of period that the WTG equipment was in planned downtime.

$$XEEPOF = \frac{((PTH + EPDTH) - (oPTH + oEPDTH))}{PDTH} \times 100$$

3.B.4. OMC Equipment Equivalent Maintenance Outage Factor (XEEMOF)
% of period that the WTG equipment was in maintenance downtime.

$$XEEMOF = \frac{((MTH + EMDTH) - (oMTH + oEMDTH))}{PDTH} \times 100$$

3.B.5. OMC Equipment Equivalent Forced Outage Factor (XEEFOF)
% of period that the WTG equipment was forced off line. Including low and high winds.

$$XEEFOF = \frac{((FTH + EFDTH) - (oFTH + oEFDTH))}{PDTH} \times 100$$

3.B.6. OMC Equipment Equivalent Unplanned Outage Factor (XEEUOF)
% of period that the WTG equipment was unavailable due to forced and maintenance downtime. For generation resource planning.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$XEEOUF = \frac{[(UOHrs + UDerateOHrs) - (UOMCHrs + UOMCDerateHrs)]}{PDTH} \times 100$$

3.B.7. OMC Equipment Equivalent Scheduled Outage Factor (XEESOF)
% of period that the WTG equipment was unavailable due to maintenance and planned downtime.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$XEESOF = \frac{[(SOHrs + SODerateHrs) - (SOMCHrs + SOMCDerateHrs)]}{PDTH} \times 100$$

3.B Equipment Performance Rates (without OMC hours)

3.B.8. OMC Equipment Equivalent Planned Outage Rate (XEEPOR)
Probability of planned WTG equipment downtime when needed for load.

$$XEEPOR = \frac{((PTH + EPDTH) - (oPTH + oEPDTH))}{[CTH + (PTH - oPTH) + RUTH]} \times 100$$

3.B.9. OMC Equipment Equivalent Maintenance Outage Rate (XEEMOR)
Probability of maintenance WTG equipment downtime when needed for load.

$$XEEMOR = \frac{((MTH + EMDTH) - (oMTH + oEMDTH)}{[CTH + (MTH - oMTH) + RUTH]} \times 100$$

3.B.10. OMC Equipment Equivalent Forced Outage Rate (XEEFOR)
Probability of forced WTG equipment downtime when needed for load.

$$XEEFOR = \frac{((FTH + EFDTH) - (oFTH + oEFDTH))}{[CTH + (FTH - oFTH) + RUTH]} \times 100$$

3.B.11. OMC Equipment Equivalent Unplanned Outage Rate (XEEUOR)
Probability of forced or maintenance WTG equipment downtime (including high or low winds) when needed for load.

$$XEEUOR = \frac{[(FTH + MTH + EFDTH + EMDTH) - (oFTH + oMTH + oEFDTH + oEMDTH)]}{CTH + [(FTH + MTH) - (oFTH + oMTH)] + RUTH} \times 100$$

3.B.12. OMC Equipment Equivalent Scheduled Outage Rate (XEESOR)
Probability of maintenance or planned WTG equipment downtime when needed for load.

$$XEESOR = \frac{[(MTH + PTH + EMDTH + EPDTH) - (oMTH + oPTH + oEMDTH + oEPDTH)]}{CTH + [(MTH + PTH) - (oMTH + oPTH) + RUTH]} \times 100$$

SECTION 4:

Pooled Resource and Equipment Calculations without OMC Hours

This section provides un-weighted pooling of turbine-hours which gives the same weight to each unit in the group regardless of size. Sums, ∑(), in this section refer to the summation for each sub-group. Only turbines of equal capacity's should use this type of pooling.

4.A Pooled Resource Performance Factors (without OMC hours)

4.A.1. Pooled OMC Resource Equivalent Availability Factor (PXREAF)
% of period that the plant was available.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$PXREAF = \frac{\sum[PDTH - (OutageHrs + DeratedHrs + RUTH) + (OMCHrs + DeratedOMCHrs)]}{\sum PDTH} \times 100$$
$$\approx (100 - PXREUF)$$

4.A.2. Pooled OMC Resource Equivalent Unavailability Factor (PXREUF)
% of period that the plant was unavailable.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$PXREUF = \frac{\sum[(OutageHrs + DeratedHrs + RUTH) - (OMCHrs + DeratedOMCHrs)]}{\sum PDTH} \times 100$$
$$\approx (100 - PXREAF)$$

4.A.3. Pooled OMC Resource Equivalent Planned Outage Factor (PXREPOF)
% of period that the plant was in planned downtime.

$$PXREPOF = \frac{\sum((PTH + EPDTH) - (oPTH + oEPDTH))}{\sum PDTH} \times 100$$

4.A.4. Pooled OMC Resource Equivalent Maintenance Outage Factor (PXREMOF)
% of period that the plant was in maintenance downtime.

$$PXREMOF = \frac{\sum\left((MTH + EMDTH) - (oMTH + oEMDTH)\right)}{\sum PDTH} \times 100$$

4.A.5. Pooled OMC Resource Equivalent Forced Outage Factor (PXREFOF)
% of period that the plant was forced off line. Including low and high winds.

$$PXREFOF = \frac{\sum\left[\left((FTH + EFDTH) - (oFTH + oEFDTH\right) + RUTH\right]}{\sum PDTH} \times 100$$

4.A.6. Pooled OMC Resource Equivalent Unplanned Outage Factor (PXREUOF)
% of period that the plant was unavailable due to forced and maintenance downtime. For generation resource planning.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$PXREOUF = \frac{\sum\left[\left(UOHrs + UDerateOHrs + RUTH\right) - \left(UOMCHrs + UOMCDerateHrs\right)\right]}{\sum PDTH} \times 100$$

4.A.7. Pooled OMC Resource Equivalent Scheduled Outage Factor (PXRESOF)
% of period that the plant was unavailable due to maintenance and planned downtime.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$PXRESOF = \frac{\sum\left[\left(SOHrs + SODerateHrs\right) - \left(SOMCHrs + SOMCDerateHrs\right)\right]}{\sum PDTH} \times 100$$

4.A Pooled Resource Performance Rates (including resources without OMC hours)

4.A.8. Pooled OMC Resource Equivalent Planned Outage Rate (PXREPOR)
Probability of planned plant downtime when needed for load.

$$PXREPOR = \frac{\sum\left((PTH + EPDTH) - (oPTH + oEPDTH)\right)}{\sum\left[CTH + (PTH - oPTH)\right]} \times 100$$

4.A.9. Pooled OMC Resource Equivalent Maintenance Outage Rate (PXREMOR)
Probability of maintenance plant downtime when needed for load.

$$PXREMOR = \frac{\sum\left((MTH + EMDTH) - (oMTH + oEMDTH)\right)}{\sum\left[CTH + \left(MTH - oMTH\right)\right]} \times 100$$

4.A.10. Pooled OMC Resource Equivalent Forced Outage Rate (PXREFOR)
Probability of forced plant downtime when needed for load.

$$PXREFOR = \frac{\sum\left[\left((FTH + EFDTH) - (oFTH + oEFDTH\right) + RUTH\right]}{\sum\left[CTH + \left(FTH - oFTH\right) + RUTH\right]} \times 100$$

4.A.11. Pooled OMC Resource Equivalent Unplanned Outage Rate (PXREUOR)

Probability of forced or maintenance plant downtime (including high and low winds) when needed for load.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$PXREUOR = \frac{\sum\left[\left(UOHrs + UDerateOHrs + RUTH\right) - \left(UOMCHrs + UOMCDerateHrs\right)\right]}{\sum\left[(CTH + ((UOHrs + RUTH) - UOMCHrs)\right]} \times 100$$

4.A.12. Pooled OMC Resource Equivalent Scheduled Outage Rate (PXRESOR)

Probability of maintenance or planned plant downtime when needed for load.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$PXRESOR = \frac{\sum\left[\left(SOHrs + SODerateHrs\right) - \left(SOMCHrs + SOMCDerateHrs\right)\right]}{\sum\left[\left(CTH + SOHrs\right) - \left(SOMCHrs\right)\right]} \times 100$$

4.B Pooled Equipment Performance Factors (without OMC hours)

4.B.1. Pooled OMC Equipment Equivalent Availability Factor (PXEEAF)

% of period that the WTG equipment was available.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = \left(oFTH + oMTH + oPTH\right)$$
$$DeratedOMCHrs = \left(oEFDTH + oEMDTH + oEPDTH\right)$$

$$PXEEAF = \frac{\sum\left[PDTH - (OutageHrs + DeratedHrs) + (OMCHrs + DeratedOMCHrs)\right]}{\sum PDTH} \times 100$$
$$\approx \left(100 - PXEEUF\right)$$

4.B.2. Pooled OMC Equipment Equivalent Unavailability Factor (PXEEUF)
% of period that the WTG equipment was unavailable.

$$OutageHrs = (FTH + MTH + PTH)$$
$$DeratedHrs = (EFDTH + EMDTH + EPDTH)$$
$$OMCHrs = (oFTH + oMTH + oPTH)$$
$$DeratedOMCHrs = (oEFDTH + oEMDTH + oEPDTH)$$

$$PXEEUF = \frac{\sum[(OutageHrs + DeratedHrs) - (OMCHrs + DeratedOMCHrs)]}{\sum PDTH} \times 100$$
$$\approx (100 - PXEEAF)$$

4.B.3. Pooled OMC Equipment Equivalent Planned Outage Factor (PXEEPOF)
% of period that the WTG equipment was in planned downtime.

$$PXEEPOF = \frac{\sum((PTH + EPDTH) - (oPTH + oEPDTH))}{\sum PDTH} \times 100$$

4.B.4. Pooled OMC Equipment Equivalent Maintenance Outage Factor (PXEEMOF)
% of period that the WTG equipment was in maintenance downtime.

$$PXEEMOF = \frac{\sum((MTH + EMDTH) - (oMTH + oEMDTH))}{\sum PDTH} \times 100$$

4.B.5. Pooled OMC Equipment Equivalent Forced Outage Factor (PXEEFOF)
% of period that the WTG equipment was forced off line. Including low and high winds.

$$PXEEFOF = \frac{\sum((FTH + EFDTH) - (oFTH + oEFDTH))}{\sum PDTH} \times 100$$

4.B.6. Pooled OMC Equipment Equivalent Unplanned Outage Factor (PXEEUOF)

% of period that the WTG equipment was unavailable due to forced and maintenance downtime. For generation resource planning.

$$UOHrs = (FTH + MTH)$$
$$UDerateOHrs = (EFDTH + EMDTH)$$
$$UOMCHrs = (oFTH + oMTH)$$
$$UOMCDerateHrs = (oEFDTH + oEMDTH)$$

$$PXEEOUF = \frac{\sum\left[\left(UOHrs + UDerateOHrs\right) - \left(UOMCHrs + UOMCDerateHrs\right)\right]}{\sum PDTH} \times 100$$

4.B.7. Pooled OMC Equipment Equivalent Scheduled Outage Factor (PXEESOF)

% of period that the WTG equipment was unavailable due to maintenance and planned downtime.

$$SOHrs = (PTH + MTH)$$
$$SODerateHrs = (EPDTH + EMDTH)$$
$$SOMCHrs = (oPTH + oMTH)$$
$$SOMCDerateHrs = (oEPDTH + oEMDTH)$$

$$PXEESOF = \frac{\sum\left[\left(SOHrs + SODerateHrs\right) - \left(SOMCHrs + SOMCDerateHrs\right)\right]}{\sum PDTH} \times 100$$

4.B Pooled Equipment Performance Rates (without OMC hours)

4.B.8. Pooled OMC Equipment Equivalent Planned Outage Rate (PXEEPOR)

Probability of planned WTG equipment downtime when needed for load.

$$PXEEPOR = \frac{\sum\left[(PTH + EPDTH) - (oPTH + oEPDTH)\right]}{\sum\left[CTH + (PTH - oPTH) + RUTH\right]} \times 100$$

4.B.9. Pooled OMC Equipment Equivalent Maintenance Outage Rate (PXEEMOR)

Probability of maintenance WTG equipment downtime when needed for load.

$$PXEEMOR = \frac{\sum\left[(MTH + EMDTH) - (oMTH + oEMDTH)\right]}{\sum\left[CTH + (MTH - oMTH) + RUTH\right]} \times 100$$

4.B.10. Pooled OMC Equipment Equivalent Forced Outage Rate (PXEEFOR)
Probability of forced WTG equipment downtime when needed for load.

$$PXEEFOR = \frac{\sum\left[(FTH + EFDTH) - (oFTH + oEFDTH)\right]}{\sum\left[CTH + (FTH - oFTH) + RUTH\right]} \times 100$$

4.B.11. Pooled OMC Equipment Equivalent Unplanned Outage Rate (PXEEUOR)
Probability of forced or maintenance WTG equipment downtime (including high and low winds) when needed for load.

$$PXEEUOR = \frac{\sum\left[(FTH + MTH + EFDTH + EMDTH) - (oFTH + oMTH + oEFDTH + oEMDTH)\right]}{\sum\left[CTH + \left[(FTH + MTH) - (oFTH + oMTH)\right] + RUTH\right]} \times 100$$

4.B.12. Pooled OMC Equipment Equivalent Scheduled Outage Rate (PXEESOR)
Probability of maintenance or planned WTG equipment downtime when needed for load.

$$PXEESOR = \frac{\sum\left[(MTH + PTH + EMDTH + EPDTH) - (oMTH + oPTH + oEMDTH + oEPDTH)\right]}{\sum\left[CTH + (MTH + PTH) - (oMTH + oPTH) + RUTH\right]} \times 100$$

Appendix F – Reference Tables

If you would like to add an item to any of the tables, please e-mail your request to GADS at gads@nerc.net

Table 1 - Country

Country	
Name	**Abbreviation**
Canada	CA
Mexico	MX
United States	US

Table 2.1 - States

United States					
Name	**Abb.**	**Name**	**Abb.**	**Name**	**Abb.**
Alabama	AL	Kentucky	KY	Oklahoma	OK
Alaska	AK	Louisiana	LA	Oregon	OR
American Samoa	AS	Maine	ME	Pennsylvania	PA
Arizona	AZ	Maryland	MD	Puerto Rico	PR
Arkansas	AR	Massachusetts	MA	Rhode Island	RI
California	CA	Michigan	MI	South Carolina	SC
Colorado	CO	Minnesota	MN	South Dakota	SD
Connecticut	CT	Mississippi	MS	Tennessee	TN
Delaware	DE	Missouri	MO	Texas	TX
District of Columbia	DC	Montana	MT	Utah	UT
Florida	FL	Nebraska	NE	Vermont	VT
Georgia	GA	Nevada	NV	Virgin Islands	VI
Guam	GU	New Hampshire	NH	Virginia	VA
Hawaii	HI	New Jersey	NJ	Washington	WA
Idaho	ID	New Mexico	NM	West Virginia	WV
Illinois	IL	New York	NY	Wisconsin	WI
Indiana	IN	North Carolina	NC	Wyoming	WY
Iowa	IA	North Dakota	ND		
Kansas	KS	Ohio	OH		

Table 3.2 - Provinces

Canada			
Name	**Abb.**	**Name**	**Abb.**
Alberta	AB	Nova Scotia	NS
British Columbia	BC	Ontario	ON
Manitoba	MB	Prince Edward Island	PE
New Brunswick	NB	Quebec	QC
Newfoundland and Labrador	NL	Saskatchewan	SK

Table 4.3 - States

Mexico					
Name	**Abb.**	**Name**	**Abb.**	**Name**	**Abb.**
Aguascalientes	AG	Guerrero	GR	Quintana Room	QR
Baja California	BC	Hidalgo	HG	San Luis Potosi	SL
Baja California Sur	BS	Jalisco	JA	Sinaloa	SI
Campeche	CP	Mexico	EM	Sonora	SO
Chiapas	CH	Michoacán	MH	Tabasco	TA
Chihuahua	CI	Morelos	MR	Tamaulipas	TM
Coahuila	CU	Nayarit	NA	Tlaxcala	TL
Colima	CL	Nuevo Leon	NL	Veracruz	VZ
Distrito Federal	DF	Oaxaca	OA	Yucatan	YC
Durango	DG	Puebla	PU	Zacatecas	ZT
Guanajuato	GJ	Queretaro	QA		

Table 3 - Wind Regimes

Wind Regime	Entry
Seashore	1
Plain	2
Plateau	3
Hills	4
Mountain	5
Ridge	6
Off Shore	7

Table 5 - SCADA Manufacturers

SCADA Manufacturer	Entry
Emerson	ES
Garrard Hassan	GH
General Electric Co.	GE
Mita-Teknik	MTK
Scadabase	SCB
Second Wind	SC
Vestas	VES
Siemens	SIE
Proprietary	PRO
Enercon	EN
Nordex	NOR
Fenway	FEN
Mitsubishi	MHI
Honeywell	HON
Gamesa	GAM
Other	OT

Table 6 – Turbine Manufacturers

Turbine Manufacturer	Entry
Clipper	CL
DanWin	DW
Denertec S.A.C.	DT
Earth Wind and Power LLC	EWP
Enercon Gmbh	EC
General Electric	GE
Green Energy Technologies	GET
Kennetech	KE
MHI	MHI
Micon	MI
Nordex	NX
Prime Wind Power International	PW
R.E. Power Systems Ag	REP
Siemens Corp.	SC
Stock Equipment Co.	SE
Urban Green Energy	UGE
Vestas	VES
Wind Energy Solutions	WES
Winwind	WW
Zond	ZD
Other	OTHER
Goldwind	GW
Gamesa	GM
Acciona	AC

Table 6 – Wind Turbulence

Turbulence	Entry	Intensity
Low	1	<0.10
Mild	2	>=0.10<0.15
Moderate	3	>=0.15<0.20
Strong	4	>=0.20<0.25
Severe	5	>=0.25

Per NREL Handbook[2] – Turbulence Intensity: Wind turbulence is the rapid disturbances or irregularities in the wind speed, direction, and vertical component. It is an important site characteristic, because high turbulence levels may decrease power output and cause extreme loading on wind turbine components. The most common indicator of turbulence for siting purposes is the standard deviation (σ) of wind speed. Normalizing this value with the mean wind speed gives the Turbulence Intensity (TI). This value allows for an overall assessment of a site's turbulence.

[2] The Wind Resource Assessment Handbook was developed under National Renewable Energy Laboratory (NREL) Subcontract No. TAT-5-15283-01 April 1997

TI is a relative indicator of turbulence with low levels indicated by values less than or equal to 0.10, moderate levels to 0.25, and high levels greater than 0.25. TI is defined as σ /V.

σ = the standard deviation of wind speed V =
the mean wind speed.

Table 7 – Wind Shear

Turbulence	Entry	Intensity
Smooth	1	<0.30
Moderately Rough	2	>=0.20<0.30
Rough	3	>=0.10<0.20
Very Rough	4	>=0.10

Shear exponent (lower blade tip to hub height)

As a first approximation, the wind shear exponent is often assigned a value of 0.143, known as the 1/7th power law, to predict wind profiles in a well-mixed atmosphere over flat, open terrain. However, higher exponent values are normally observed over vegetated surfaces and when wind speeds are light to moderate (i.e., under 7 m/s or 16 mph).

Per NREL Handbook[2]

1. Vertical wind shear exponent: Wind shear is defined as the change in horizontal wind speed with a change in height. The wind shear exponent (α) should be determined for each site, because its magnitude is influenced by site-specific characteristics. The 1/7th power law (as used in the initial site screening) may not be applied for this purpose, as actual shear values may vary significantly from this value. Solving the power law equation for α gives

α=Log10 [v2/v1]/Log10 [z2/z1]

Where
v2 = the wind speed at height z2; and v1 =
the wind speed at height z1.

Table 8 – Month Reference

Monthly Summaries	
01 – January	07 – July
02 - February	08 – August
03 – March	09 – September
04 – April	10 – October
05 – May	11 – November
06 - June	12 - December

Table 9 – Sub-group Status

Status	Entry
Active	AC
Inactive Reserve	IR
Mothballed	MB
Retired	RU

Appendix G – Outside Management Control

Outside Management Control (OMC) events occur beyond the wind plant boundaries (Interconnect) or are caused by abnormal weather. These types of events are currently categorized into Weather, Off-Taker Planned, and Off-Taker Unplanned downtime categories.

Equations with and without OMC are included for both resource and equipment equations.

OMC events can be Planned, Maintenance, Forced Outage, or Derating Events.

The following excerpt is from the *GADS Data Reporting Instructions*, *Appendix K.*

> The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control. After reviewing the work used by others, the following is provided as guidelines for determining what is and is not outside plant management control:
>
> There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control.
>
> It may be assumed that all problems within the power station boundary are within plant management control; however, this is not always the case. Therefore, there is a need for some additional clarification as to what is and what is not under plant management control.
>
> It is easier to identify actions outside plant management control than to identify the responsibilities of plant management. Therefore, the following are considered to be outside (external) of plant management control. All other items are considered within their jurisdiction and are the responsibility of the plant management for calculating power plant performance and statistics.
>
> Energy losses due to the following causes should not be considered when computing the unit controllable performance because these losses are not considered to be under the control of plant management:
>
> - Grid connection or substation failure is not under management control. This relates to problems with transmission lines and switchyard equipment outside the boundaries of the plant as specified by the "boundary of plant responsibility" shown in *Figure 3-1*.
> - Acts of nature such as ice storms, tornados, winds, lightning, etc. are not under plant management control, whether inside or outside the plant boundary.
> - Terrorist attacks on the generating/transmission facilities or transmission operating/repair errors are not under plant management control.
> - Labor strikes. Outages or load reductions caused by labor strikes are not normally under the direct control of plant management. The strikes are within manufacturer companies and transportation companies. However, direct plant management grievances that result in a walkout or strike are under plant management control and are included as penalties against the plant.

Appendix H – Outage Classification Guidelines

General Considerations

1. Segregating maintenance outages (MO) from forced outages (FO) is the single largest area for misunderstanding and abuse. MO's are defined as outages that can be deferred until the following week or, if they occur on the weekend, they can be deferred through the next (not current) weekend. When equipment breaks, it cannot be deferred and is a FO, so the problem comes when equipment is close to breaking. For example, during an annual maintenance, 3 teeth were found missing from the gearbox high speed gear. The turbine was running fine before inspection. If it is turned off for repair, is it an MO or a FO? This is where good judgment and engineering support helps. What is the risk of failure if the equipment is allowed to run for another week? If the risk is high, then the event is an FO.
2. Weather downtime is another area for abuse. The tendency is to attribute every event that occurs during Weather OMC to the storm. There should be clear predefined linkage between the event and the storm. For example, a blade icing event occurs and some of the turbines shut down so the ice clearly has impacts. Another example would be cable twist faults caused by a frozen wind direction sensor.
3. Equipment failure or Weather OMC can also be tricky. For example, a turbine shuts down on a wind speed error caused by ice on the anemometer. If the anemometer has a heater to prevent ice build-up, then the equipment failed (EFOR). If the anemometer had no heater the event would be classified at Weather OMC. Think about other forms of protection such as blade lightning protection.
4. Recovering from a site wide event like an outage (OMC) or a Plant substation breaker trip can be challenging to classify. Not all turbines will automatically restart when power is restored. The assumption here is that a turbine should be able to handle an unplanned outage without a component failure. Electrical conditions during an outage are complex and turbines may fault due to out of spec electrical parameters. The OMC ends when one of the following 3 conditions occur:
    a. The turbine automatically restarts.
    b. The turbine is reset from SCADA and restarts.
    c. The turbine is visited and restarted locally. If the turbine fails to restart after a local reset, a FO event begins at that point.
5. Occasionally, events will delay resets or repairs. Heavy snow is an example of this. In the Off-Taker outage above, snow could have delayed access to the turbine for weeks. The Off-Taker outage would not end until there is access to the turbine and the turbine reset. The event type does not change; it is only delayed (See Delays). Other types of delays could be floods, earthquakes, fires, parts availability, equipment availability, labor etc.
6. At times events will overlap. The first-in-first-out rule should apply in this case. An example of this would be a failed gearbox (FO). Several days later, the Off-Taker takes a 2 week maintenance outage (OMC MO). The gearbox remains FO until the repair is completed and then becomes part of the OMC MO.

Forced Outage – FO

An unplanned outage that usually results from a mechanical, electrical, hydraulic, control system trip or an operator initiated trip in response to a unit alarm. The turbine is not capable of running under the MO rules.

1. **Component failures**: Most FOs will be component failures that require replacement and or repair. Examples are towers, generators, controllers, loose wire & etc.
2. **Trips or faults:** These remove the turbine from availability until corrected. Examples are overproduction, vibration, etc. Events that are part of normal operation, like cable untwisting and battery testing, are considered as available hours (RUTH).
3. **Condition Assessment**: Sometimes failing components are identified through condition assessment. If the component fails before the repair or replacement occurs it is FO. For example, a high-speed gearbox bearing is overheating and is scheduled for replacement. If the bearing fails before the scheduled replacement time, the outage is FO.
4. **Balance of Plant (BOP)**: components like underground cabling failure can cause FO. BOP failures often have parallel and undamaged components that need to be de-energized to complete the repairs safely. BOP failures usually impact many turbines and their repairs are usually not delayed. Under this condition, the parallel circuits are part of the FO. If the primary repair will be delayed for a week or 2, the parallel circuit outage could be considered a MO.
5. **No Wind**: Turbine repairs often occur during no or low wind periods. Although there are no production losses, the turbine's FO hours still accumulate. For example, if turbine fails a hydraulic motor, but there is no wind anywhere in the area, it is still a FO.
6. **Repeating Faults**: Occasionally, turbines fault multiple times from the same problem over a short period of time. For example, imagine that crews are dispatched to repair a turbine, but the turbine is running when the crew arrives. One might think to call this MO because the turbine is running, but due to the repetitive nature of the fault, it is FO. Here's another example: A turbine has been repeatedly faulting on pitch asymmetry. The previous night, it faulted 6 times. The turbine is later shut down to determine root cause of the problem and repair it. Therefore the turbine cannot be restarted until repaired, so it is FO.
7. **Outside Contractors:** Sometimes non-related contractors have access to the plant to service non-turbine equipment. (Oil equipment, gas lines, telephone) When digging or work occurs around high voltage (HV) or communication lines, it is the responsibility of the plant to be aware of and coordinate these events. Consider this example; a local phone company is installing a new fiber optic line that crosses the plant, and the contractor hits an underground HV cable. The site trips off and the cable requires repair. Were the crossings marked and flagged? Was the digging monitored? The event is FO even if all the proper safe guards are in place (human error).
8. **Security**: Damage caused by theft or vandalism is FO. It is the plant's responsibility to secure its equipment. For example, turbines going off-line from cable theft is under plant management control.
9. **Human Error:** Human error falls under plant management control. For example, if a technician leaves an oily rag in a nacelle that spontaneously catches fire and burns it up, the event is FO.
10. **Weather:** Weather events are often difficult to categorize. When labelling an outage as FO, determine what equipment caused the failure. For example, if a turbine has an anemometer with a heater to prevent icing, but it ices up anyway, then the heater failed and the outage would be

FO-Control System. If lightning were to strike a blade with lightning protection and cause damage, then the protection system failed, and the outage would be FO-Rotor.

11. Safety Shutdown: Safety shutdowns usually occur when neighboring equipment is in danger of harm. As an example, when a turbine runs away, neighboring turbines may be in danger of damage from flying debris. If they are shut down, they are part of the event and are FO.

Forced OMC Events

These are events that occur beyond the wind plant boundaries or are caused by abnormal weather. These events are beyond the plant manager's ability to control. **Note**: Forced OMC outages are a subset of FO.

1. **Off-Taker OMC**: Off-Taker OMC comes in several forms. Code it as External / Off-Taker (OMC) Forced.
    a. Equipment failure is a forced OMC outage.
    b. Weather outage or brown-out usually due to lightning, line slaps, icing is a forced outage.
    c. Line congestion is a limitation of the Off-Taker's equipment and is a forced outage.
    d. Long outages in very cold weather will require heaters to warm the equipment before the turbine can restart. This warm-up period is part of the Off-Taker outage.
2. **Economic OMC:** A Labor strike would go under this category since there is no problem with the equipment. Code as External / Economic (OMC) Forced.
3. **Catastrophic OMC:** Major events like tornados, hurricanes, earthquakes, wild fires are OMC.
4. **Weather Ice OMC:** When icing forces turbines off-line, it can be classified as OMC in some cases.
    a. Icing downtime due to ice on equipment like anemometers, windvanes and blades is OMC. If the turbines have protective equipment and ices over anyway, then the protection failed and the event is not OMC. However, if the protective equipment's operating specifications are exceeded, then the event is OMC.
    b. Ice on HV equipment causing tracking, line slaps or equipment failures.
    c. Safety shut downs for turbines shedding ice on highways.
5. **Weather Lightning OMC:** – If the turbines had lightning protection, but the protection failed, the event is FO. If the turbines lacked protection, then it is OMC. Code this as External/Weather – Lightning (OMC). Lightning can strike anywhere on the turbine, but the blades and nacelle usually have lightning protection. When considering lightning strikes, evaluate whether the protection work as claimed or if it was overwhelmed. There are devices and services that can help determine the magnitude of a lightning strike and if the equipment worked properly. The electrical distribution system is more often struck by lightning then the blades and nacelle, and just as with the blades and nacelle, only label an outage as OMC if the equipment lacked protection.
6. **Weather Temperature OMC:** Wind turbines have high and low ambient temperature limitations. When these limits are exceeded the turbine will shut down. Code this as External / Temperature (OMC).
7. **Communication OMC:** Many Off-Taker's, ISO's, and other groups require full-time communication with the wind plant's SCADA systems. When communication is lost with the site, the plant is required to shut down. When the loss of communication is due to external causes it should be coded as External

/ Communication OMC.

Maintenance Events – MO

These are components or systems that are close to failure or in need of modification. The turbine should be capable of running until the following week. For example, if identified on Tuesday, it should be capable of running until the following Monday. If identified on the weekend it should be capable of running through the following week. If the turbine requires maintenance and won't be able to run until the following week, then the outage is FO, not MO. Repairs can take place anytime as long as the turbine is capable of running as stated above.

1. **Condition Assessment:** The condition of the turbine is evaluated using historical trends, inspection, non-destructive testing, etc. When an issue is found, the repair is scheduled.
2. **Inspections:** Inspections by their nature are MO. If the turbine is down prior to the inspection, then it is FO.
3. **Safety Shutdowns:** Sometimes neighboring turbines or parallel circuits need to be shut down for safety. If the safety shutdown is of an immediate nature or less than the MO definition, then it is FO. Examples:
   a. A transformer failed several weeks ago and was bypassed until a replacement could be acquired. (The original event, including parallel circuits was FO). The original transformer failure remains FO, but when the rest of the circuit is de-energized to replace the transformer, the balance of the turbines are MO. All of the turbines would have the same system classification, which in this case is Electrical / Individual Turbine Transformer.
   b. A turbine gearbox failed several weeks ago (FO). In order to safely remove the rotor and gearbox, 2 neighboring turbines were shutdown. The 2 neighboring turbines are MO. The system classification for all turbines is Gearbox / Gearbox in this case.
4. **Retrofits and Upgrades:** Most of these types of events will fall into the MO category. They could include anything from upgrading the turbine software to installing a larger rotor. If the items involve long term planning (specifically in the budget), then consider PO.
5. **Economic Repair:** Sometimes it is advantageous to shut down a turbine in order to minimize costly repairs. In this case, the turbine must clearly meet the MO standards and be able to run for another week. If used inappropriately, an FO event could be disguised as an MO. For example, if a turbine is continuously faulting multiple times a day, then the outage is FO, not MO. The following are examples:
   a. A turbine has a trailing edge blade crack and can clearly run, but the crack will propagate over time, eventually leading to a blade failure. Turning the turbine off now will minimize the repair cost and prevent further damage. Plant management could decide to keep the turbine in service for another week, so the outage is MO, not FO Repairs are completed when labor and cranes are available. Code as Rotor / Blades MO.

      The main bearing temperature has been rising, and inspection indicates that the bearing should be replaced. Experience has shown that the turbine will run for several months in this condition, but there is a chance that the bearing could spin on the main shaft, significantly increasing the cost of repair. The turbine is shutdown under MO and repairs completed when a bearing and crane are available. Code as Drive Train / Main Bearings MO.
   b. A gearbox is making noise. During inspection, metal flakes are found, and spalding is occurring on the intermediate bearings. Engineering indicates that the gearbox could run for several weeks in this condition but the risk of a catastrophic failure will become significant (loss of core). The turbine is shutdown under MO, and repairs are completed

when a gearbox and crane are available. Code as Gear Box / Gear Box MO.

c. A gearbox is making noise. During inspection, metal flakes are found, and spalding is occurring on the intermediate bearings. Engineering indicates that the gearbox could run for several weeks in this condition but the risk of a catastrophic failure will become significant (loss of core). The turbine is shutdown under MO, and repairs are completed when a gearbox and crane are available. Code as Gear Box / Gear Box MO.

Maintenance OMC Events

Maintenance OMC Events are MO events that occur beyond the plant boundaries. They must also qualify under the MO rules and are a subset of MO.

1. **Off-Taker**: Off-Taker events are the most likely OMC MO event to occur. Some items on their system may need maintenance or repair, and the plant is notified ahead of time of the outage. Code as External / Off-Taker (OMC) MO.
2. **Communication**: Just like Off-Taker OMC, a required communication system may need work, and the plant is notified and shuts down at the appropriate time. Code as External / External Communication (OMC) MO.
3. **Economic**: Potentially a labor strike could meet the MO rules.

Planned Events - PO

Planned events are events that are scheduled well in advance and are usually specifically listed in the plant budget.

1. **Substation / HV Maintenance**: HV maintenance schedules are usually determined well in advance by NERC regulations. This is coded as Balance of Plant / Substation PO
2. **Turbine Preventative Maintenance**: Most turbines have a biannual maintenance schedule. This happens every year and is planned well in advance. This is coded as Wind Turbine / Preventative Maintenance PO.
3. **Retrofit**: Some retrofit projects require long term planning. An example could be replacing all the gearboxes at a plant. That would be coded as Gearbox / Gearbox PO.

Planned Events OMC

1. **Off-Taker**: Off-Taker planned event like a system upgrade. This is coded as External / Off Taker (OMC) PO.

Equivalent Hours

Equivalent hours come from events where the turbine output is limited. The causes of equivalent hours are the same as other outages, except that the hours are accounted for only in the numerator of equations. Since the turbine is running, the contactor or on-line hours are already captured in the denominator. Also note that the hours are based on the reduction in capacity and do not depend upon the wind resource. If individual turbines are turned off to meet the capacity reduction, then they are treated as regular outages (PO, MO & FO). Below are a few examples:

1. **Equipment Deterioration**: A turbine has a deteriorating main bearing. Engineering has determined that they can extend the life of the bearing by running at reduced load. Turbine output is reduced from 1.0MW to 0.8MW until repairs can take place. This is a 20% reduction in maximum capacity, so 20% of the hours would be coded as Drive Train / Main Bearing EFDTH.
2. **Partial Equipment Failure**: 1 of 4 parallel underwater feeder cables to an island fail, limiting output from the plant. There are 2 ways that the Equivalent hours are calculated:
    a. 75% of the capacity of the lines is available. Therefore 25% of the hours would be coded as Balance of Plant / Underground EFDTH.
    b. Alternatively an engineer could calculate the remaining capacity based on the cable specifications. If the remaining 3 cables can handle 85% of the capacity, 15% of the hours would be coded as Balance of Plant / Underground EFDTH.
3. **Off-Taker Constraints**: An Off-Taker limits plant output due to line congestion. This is coded as External / Off-Taker (OMC) ₒEFDTH. The following are examples:
    a. The Off-Taker limits plant output 50%. Therefore 50% of the hours are (OMC) ₒEFDTH.
    b. The Off-Taker limits the plant to 80MW, but the plant capacity is 100MW. Therefore 20% of the hours are (OMC) ₒEFDTH.
4. Equipment Maintenance: Planned work is being done on one of the 3 parallel transformers in the substation. During this time, output from the plant is limited to 2/3 of the plant's capacity. In this example, 1/3 of the turbine hours would be counted as EPDTH.

Delays

Delays are optional fields that help NERC staff understand extended outages and help management run the plant more efficiently. Delays can take many forms, such as environmental, site access, equipment, labor and materials. The delay does not change the original outage type, but helps NERC Staff understand the issues that are driving cost. Here are several examples:

1. A turbine is down for a FO gearbox event. The crane, gearbox and technicians are available to complete this task tomorrow. During the night, a storm moves in and covers the area in 3 feet of snow, delaying work for 3 weeks. The original outage does not change, and is coded as Gearbox / Gearbox FO. 3 weeks of the FO hours are explained as Force Delay Turbine Hours (FDTH). The hours for the original FO begin when the gearbox failed and end when the turbine is returned to service.

2. Cranes cannot be on the roads during the fall freeze and spring thaw in some locations Equipment failures during this time can be extended due to crane availability. The primary event still starts when the equipment failed and ends when the equipment is returned to service. The delay helps NERC understand why it took so long.

3. Weather occasionally prevents access to turbines, impacting return to service time. Delays due to snow, flooding, or a tornado scattering debris can delay access to the turbine, increasing downtime.
4. Delays occur when there is inadequate technician support available. This could be due to vacations, illness, or other personnel issues.
5. When the stock of replacement parts falls short, repairs are delayed.

Reserve Shutdown – RS

RS is a decision by plant management to shut down available turbines that are in an active state and not in outage or in danger of failure. IEEE 762 defines the condition as an economic[3] shutdown. Turbines in this state must remain available. If they are disabled in any way, like removing the controller, they move into an outage state (PO, MO, or FO). It can be difficult to discern between OMC and RS at times. The following are examples:

1. Wind Plant A is actively participating in the energy market. During certain times of the day, pricing goes negative (Negative energy pricing), so the revenue from the energy cannot cover the cost of operating the plant. The plant shuts down the turbine during these periods, which is an RS.
2. During an RS due to negative energy pricing, a technician needs a controller board to repair another turbine. As soon as the technician removes the board the turbine is no longer RS and is in an outage state (no longer available).

[3] Economic shutdown is an outage due to market or demand issues.

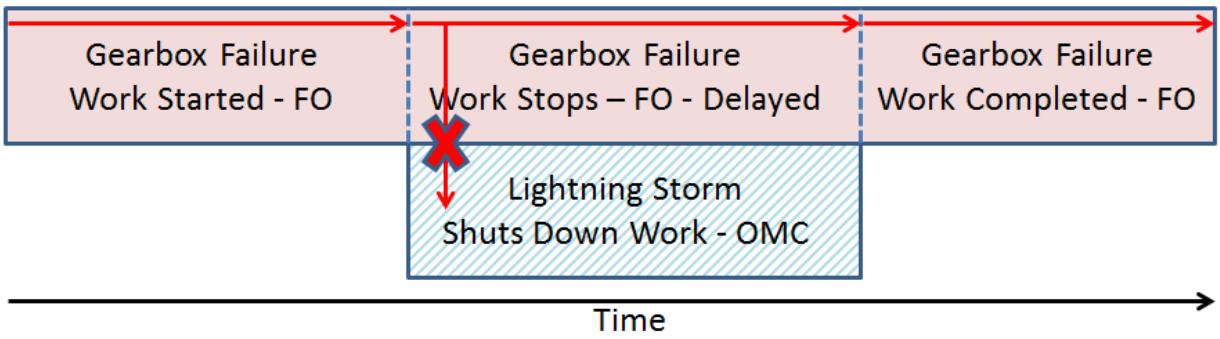
Appendix I – Overlapping Events

Often events overlap and make it confusing to classify them. Sometimes it appears that there is a penalty for something the Plant Management has no control. The general rule for overlapping events is "first in first out." In other words, the first issue must be resolved before the second issue can take control. Below are some examples:

1. A turbine is in the process of having its gearbox replaced when a lightning storm moves in and delays the work for a day.

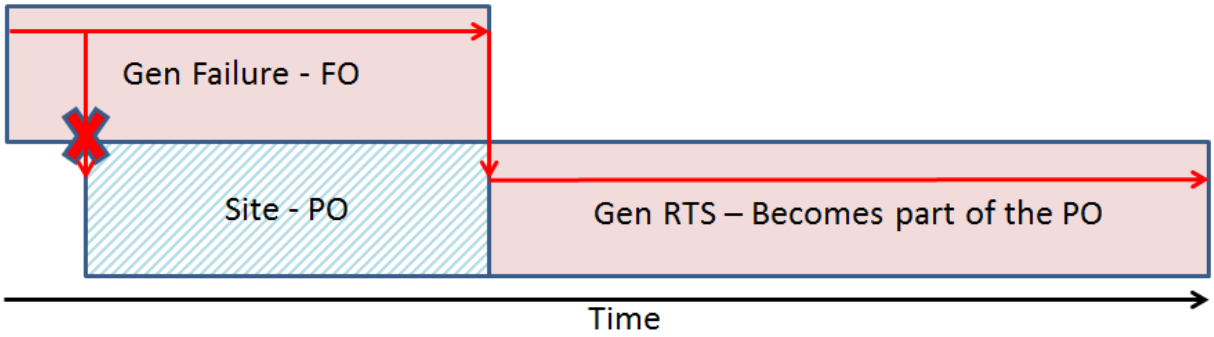
   The forced outage continues through the lightning storm. The outage type does not change but is delayed due to lightning.

Gearbox Failure with a Parallel Lightening Storm



2. The plant is planning a 3 week outage for transmission repairs. The day before the outage the generator rotor shorts out and a generator replacement is required.

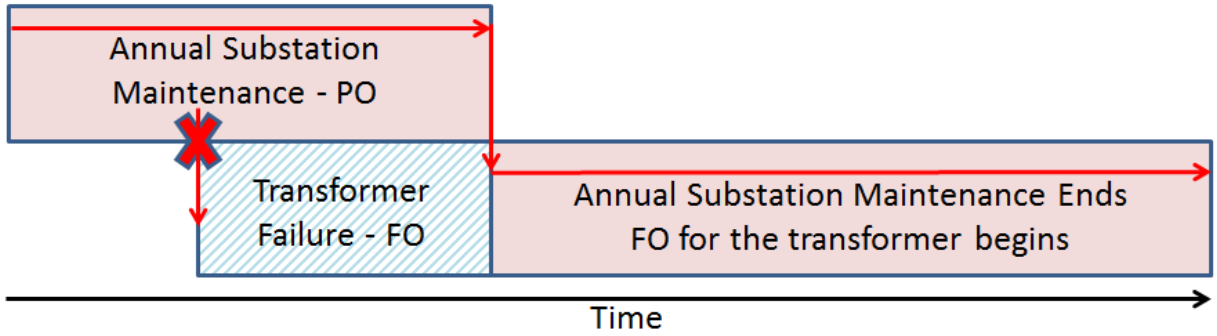
Generator Failure with a Parallel Planned Outage



   The site is de-energized. The site is on a PO except for the turbine with the bad generator which is FO. During the first week of the PO the generator gets replaced and aligned. At the point where the generator turbine is available for service it moves from a FO to PO.

3. The plant will be down for annual substation maintenance. The outage will take 3 weeks and is a PO event. During inspection, the main transformer failed the Doble test and will need to be replaced.

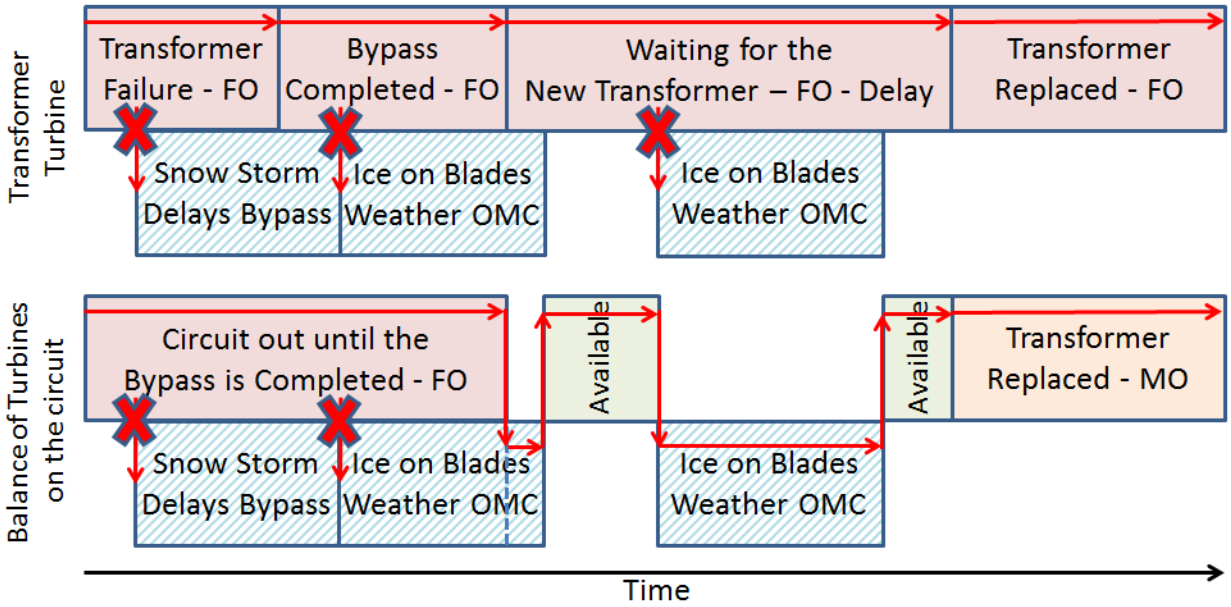
Power Transformer Found Defective During Annual Substation Maintenance



During a PO, other work can take place. The PO can even be extended if the predefined work is taking longer than expected. If additional items are found in need of repair, an MO or an FO decision needs to be made. At the end of the PO, the new outage type becomes primary.

4. A turbine pad mount transformer fails, de-energizing all the turbines on the circuit. The failed transformer was removed and bypassed, so the remaining turbines could be re-energized. During the repair period, there was a snow storm followed by an ice storm, and these problems prevented the crews from getting to the site.

A Pad Mount Transformer Fails Taking Out All the Turbines on the Circuit
The Example is Complicated by Equipment Delays and Weather



Events can be complicated, but if taken in pieces, they are easier to code. The original turbine with the failed transformer is an FO until the transformer is replaced and the turbine is available. This turbine also experienced storms, ice, and equipment delays, but they do not change the outage type.

The balance of the turbines on the circuit (collateral FO) is FO until the bypass is complete and the turbines are returned to service (RTS). Once the bypass is complete, the event is coded as External / Weather Ice (OMC). After the weather event, the turbines are available, then another icing event occurs. When the failed transformer is replaced and the bypass removed, the collateral turbines are placed into MO until repairs are completed.

Appendix J – Data Quality Control

GADS data should be reviewed for the following potential discrepancies before submission. This list is by no means comprehensive, but data not meeting these minimum requirements will be rejected. Reporting is done on a monthly basis, submitted no later than 45 days after the end of the quarter. At the time of the writing of this document, reporting is voluntary.

1. **Calendar Turbine Hours (CalTH) –** The total number of turbine hours in a month is equal to the number of turbines times the number of hours in a month. Example: January has 31 days or 744 hours. If the plant has 100 turbines than there would be 74,400 turbine hours for January.

   CalTH = (Hours in Month) X (Number of Turbines)

2. **Turbine State** – Turbines are either in an Active state (PDTH) or an Inactive state (ITH). The sum of the two equals the CalTH.

   CalTH = PDTH + ITH

3. **Inactive State** – The sum of all inactive states should equal ITH.

   ITH = (Inactive Reserve [IRTH]) + (Mothball [MBTH]) + (Retired [RTH])

4. **Active State** – The sum of all active states should equal PDTH.

   CTH – Contactor Turbine Hours
   RSTH – Reserve Shutdown Turbine Hours FTH –
   Forced Turbine Hours
   MTH – Maintenance Turbine Hours PTH –
   Planned Turbine Hours

   RUTH – Resource Unavailable Turbine Hours

   PDTH = CTH + RSTH + FTH + MTH + PTH + RUTH

5. **RUTH Hours** – RUTH is usually calculated by subtracting the known values from PDTH.

   RUTH = PDTH – (CTH + RSTH + FTH + MTH + PTH)

6. **Forced OMC Turbine Hours (ₒFTH) -** ₒFTH is a subset of FTH. Be sure the ₒFTH are included in the FTH.

7. **Maintenance OMC Turbine Hours (ₒMTH)** - ₒMTH is a subset of MTH. Be sure the ₒMTH are included in the MTH.

8. **Planned OMC Turbine Hours (ₒPTH)** - ₒPTH is a subset of PTH. Be sure the ₒPTH are included in the PTH.

9. **Equivalent Forced Derated OMC Turbine Hours (ₒEFDTH)** - ₒEFDTH is a subset of EFDTH. Be sure the ₒEFDTH are included in the EFDTH.

10. **Equivalent Maintenance Derated OMC Turbine Hours (ₒEMDTH)** - ₒEMDTH is a subset of EMDTH. Be sure the ₒEMDTH are included in the EMDTH.

11. **Equivalent Planned Derated OMC Turbine Hours (ₒEPDTH)** - ₒEPDTH is a subset of EPDTH. Be sure the ₒEPDTH are included in the EPDTH.

12. **Generation** – Generation at the turbine (GAG) >= Net Actual Generation (NAG). GAG is the generation measured at the turbine.
    NAG is GAG minus line losses, transformer losses and auxiliary load losses.

13. **Capacity** – Gross installed capacity (GIC) >= Net Maximum Capacity (NMC)
    GIC is the Wind Turbine Generator (WTG) rated capacity times the number of turbines. NMC is GIC minus line losses, transformer losses and auxiliary load losses.

14. **ID Missing** – An error will be generated if the Plant, Group or sub-group ID is missing.

15. **ID Not Found** – The Plant, Group or sub-group ID has not been registered with the data base.

16. **Performance ID Not Found** – The performance record is missing a Plant, Group, sub-group, year or period.

17. **Bad Period / Year** – This error may occur when importing Hours or Performance files. This happens when the entered year is earlier than 1980 or greater than the current year, or if the entered period (month) is not within the range of 1-12.

18. **Invalid System** – This happens when the System Identifier does not match any found within the program.

19. **No Name or Description** – This error may occur when importing sub-group, Group, or Plant files. This happens when the name / description field is blank in the incoming CSV file.

Appendix K – Frequently Asked Questions

What is the difference between a rate (EFOR) and a factor (FOF)?

The difference between rates and factors is often confusing. Under normal operating conditions, the results of the two types of calculations will give similar results, but may vary widely during various outage conditions.

A **factor** is defined as a percent of the whole. Equation 1.B.5, Equipment Equivalent Forced Outage Factor

$$EEFOF = \frac{(FTH + EFDTH)}{PDTH} X100$$

Notice the denominator in the equation is all the hours, the whole pie. See figure K1.

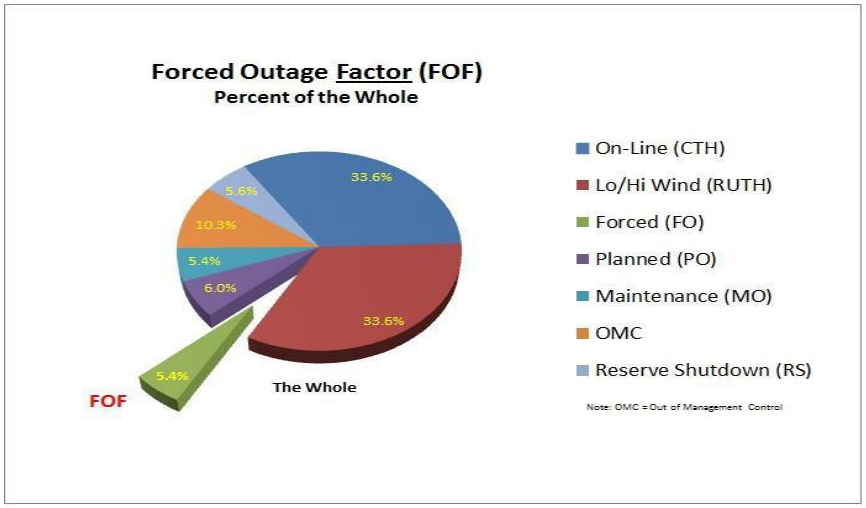


Figure K1

A **rate** is defined as a percent of the available hours.

Equation 1.B.12, Equipment Equivalent Forced Outage Rate (EEFOR).

$$EEFOR = \frac{(FTH + EFDTH)}{(CTH+FTH+RUTH)} X100$$

Notice that the numerator is the same for the factor and rate calculations. The denominator is different containing contactor hours, low / high winds and the hours for the rate we are calculating, in this case forced hours. See figure K2.

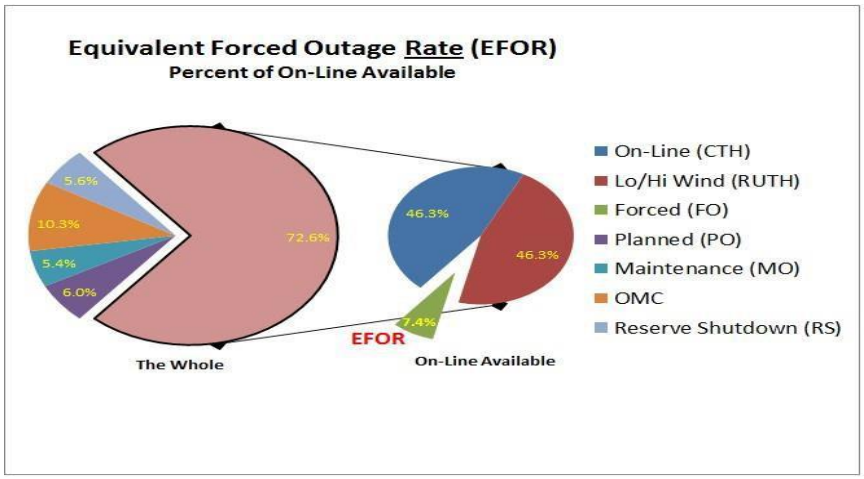


Figure K2

When the value in the denominator is similar between the two equations, the results will be similar. When large numbers aren't included in the denominator, the result can be surprising. An example of this is: Plant A has 100 turbines, and there are 744 hours in the month. Therefore PDTH = 74,400 hrs. The plant will be down the entire month for a planned substation outage. Going into the outage, there is one turbine on FO (Gearbox). The gearbox is not repaired during the outage.

What are equivalent hours?

At times, turbines or systems are not out of service but their capacity is reduced. During this time, the turbine or system is still accumulating contactor hours. The reduced capacity is calculated as equivalent hours and added to the hours in the numerator only. For example, a wind turbine is derated 25% for 5 days. The equivalent hours = 5 days x 24 hrs. /day x 25% = 30 hrs.

What roll-up method should be used for multiple technologies?

Roll-up calculations for metrics that have physical characteristics are straightforward. Simply sum the metric and divide by the number of sites. A metric with physical characteristics would be dollars, kilowatts, etc. Hour-type metrics have something happening during a period of time, and its value or has been the point of contention. Some have said an hour is an hour everywhere, therefore the roll-up should be the same as the physical characteristic metrics. An example of this is comparing one hour of run time for a 2,000 MW nuclear plant to a 1 MW wind turbine. Clearly 1 hour of EFOR at the nuclear plant has greater consequences then 1 hour of EFOR at the wind turbine. Another way of looking at this is a 2,000 MW nuclear plant compared to a wind plant with 2,000 1MW wind turbines.

The pooling equations previously listed work reasonably well when rolling up hourly metrics with turbines of the same installed capacity, but errors can be introduced when plant net capacity factors (NCF) vary widely. Wind is different from conventional generation in several aspects, such as large numbers of smaller units, a variable fuel source, and temperature constraints. The impact to the wind turbine is no different than adjusting a conventional plant's capacity based upon inlet water temperature cooling capacity. The site dependable capacity varies, depending upon the current environment, therefore there can be a large difference between the installed capacity and dependable capacity.

Some of the methods for roll-up data into a portfolio metric are:

1. **Averaging**: Averaging percentages only works in special situations. Even averaging monthly data for

the same site can have issues, such as different number of days per month and large variations in monthly NCF. For monthly single site roll-up, one of the pooling equations would be better. Averaging should not be used.

2. **Pooling:** The pooling equations only work when rolling up plants with similar turbine capacities. When selecting the pool, plants with similar resource characteristics should be selected.
3. **Generation:** Generation weighting will work when EFOR is low. When EFOR gets above 10%, significant errors occur. At 100% EFOR there is no generation therefore no weight (See Figure K3). This method should be avoided.
4. **Installed Capacity:** Installed capacity weighting works but does not take into account the differences in turbine efficiency and plant capability based on resources.
5. **Net Dependable Energy**: Net dependable energy is the maximum amount of energy that could be produced based on the resource available. This could also be called the entitlement for the project for the specified period of time. This method works in all cases. (See Figure K3)
6. **Net Dependable Capacity (NDC):** This gives the same result as Net dependable energy. NDC is what the plant was capable of for that month. The installed capacity may be much higher but over a period of time a wind plant will never achieve 100% of its installed capacity vs. a conventional plant can easily achieve 100% of its rated capacity.

Appendix L – Performance Data

Metric	Performance	System	Component
Sub Group Status	?	?	?
Gross Actual Generation (MWh)	?	?	?
Net Actual Generation (MWh)	?	?	?
Group Installed Capacity (MW)	?	?	?
Net Maximum Capacity (MW)	?	?	?
Period Turbine Hrs.	?	?	?
Contactor Turbine Hrs.	?	?	?
Reserve Shutdown Turbine Hrs.	?	?	?
Forced Turbine Hrs.	?	?	?
Maintenance Turbine Hrs.	?	?	?
Planned Turbine Hrs.	?	?	?
OMC Forced Turbine Hrs.	?	?	?
OMC Maintenance Turbine Hrs.	?	?	?
OMC Planned Turbine Hrs.	?	?	?
Resource Unavailable Turbine Hrs.	?	?	?
Inactive Reserve Turbine Hrs.	?	?	?
Mothball Turbine Hrs.	?	?	?
Retired Turbine Hrs.	?	?	?
Equivalent Forced Derated Turbine Hrs.	?	?	?
Equivalent Maintenance Derated Turbine Hrs.	?	?	?
Equivalent Planned Derated Turbine Hrs.	?	?	?
OMC Equivalent Forced Derated Turbine Hrs.	?	?	?
OMC Equivalent Maintenance Derated Turbine Hrs.	?	?	?
OMC Equivalent Planned Derated Turbine Hrs.	?	?	?
Component Force Outage Hrs.		?	?
Component Force Outage Occurrences		?	?
Component Maintenance Outage Hrs.		?	?
Component Maintenance Occurrences		?	?
Component Planned Outage Hrs.		?	?
Component Planned Occurrences Sub-		?	?
Component Force Outage Hrs. Sub-Component			?
Force Outage Occurrences Sub-Component			?
Maintenance Outage Hrs. Sub-Component			?
Maintenance Occurrences Sub-Component			?
Planned Outage Hrs.			?
Sub-Component Planned Occurrences			?

Notes:

1. There are 15 System categories
2. There are 117 Component categories

Appendix M – Major Changes from the Previous Version

- Added a Typical Wind Plant Layout diagram with Group / Sub-group clarification
- Cleaned up the definition of the plant boundary
- Moved tables to the Appendix
- Group Record Changes:
  - "Commercial Date" was changed to "Commissioning Year"
  - Deleted SCADA type
  - Added Off-Shore to Wind Regime
  - Revised the list of SCADA (Supervisory Control and Data Acquisition) manufacturers
- Sub-Group Record Changes
  - Data columns 16-22 were changed to optional.
  - Defined Turbulence Intensity
  - Change - column 12 changed "Make" to "Model"
  - Change – column 13 changed from "Model" to "Version"
  - Defined Wind Shear
  - Added reference Anemometer Height
- Performance Reporting Record Changes
  - Deleted data columns 25-30
  - Added derate terms columns 31-35
  - Added delay terms columns 36-38 – Optional
- Component Outage Reporting
  - Added derate terms columns 15-17
  - Added delay terms columns 18-20
- Appendix A – GADS-W Data Release Guidelines
  - Revised to focus on GADS-W
  - Added a section outlining the data request process
- Appendix B – Utility Identification Codes
  - Codes moved to NERC Web site
  - Added the procedure for getting a new NERC Utility Code
- Appendix C – System Component Codes
  - Balance of Plant
    - Change 650 – Feeder/Collection changed to Underground.
    - Added 1037 – Breaker
    - Added 1038 – Main Substation Transformer
    - Added 1039 – Switches

  - Added 1040 – Wave Trap
  - Added 1041 – CT / PT (Current Transformer, Potential Transformer)
  - Added 1042 – Battery Systems
  - Added 1043 – Site Communication
  - Added 1044 – Fuses
  - Added 1075 – Transmission (Gen-Tie)
- Brake
  - Added 1045 – Brake Hydraulic System
- Control System
  - Moved 641 –Rotor Current Control (RCC) moved to Generator
  - Added 1046 – Hardware
  - Added 1047 – Power Supply
  - Added 1048 – Control Cabinet Filtration
  - Added 1049 – Control Slip Rings
- Drive Train
  - Change 615 – High Speed changed to Rotor Coupling
- Electrical
  - Change 662 – Transformers changed to Individual Turbine Transformers
  - Added 1050 – Current Transformers
  - Added 1051 – Power Transformers
  - Added 1052 – Converter Cooling
  - Added 1053 – Power Supply
- External
  - Change 681 – Add OMC (Out of Management) to the end.
  - Change 675 – Add OMC to the end.
  - Change 678 – Add OMC to the end.
  - Change 676 – Add OMC to the end.
  - Delete 680 – Catastrophic
  - Delete 677 – Weather – Ice
  - Added 1054 – Bat / Bird (OMC)
  - Added 1055 – Noise / Flicker (OMC)
  - Added 1056 – 3rd Party (OMC)
  - Added 1057 – External Communication (OMC)
  - Added 1076 – External Weather - Turbulence
- Generator / Exciter

    - Moved From 641 – VRCC (Vestas Rotor Current Control) moved from Control System
    - Added 1058 – High Speed Coupling
    - Added 1059 – Power Slip Rings
  - Hydraulic System
    - Added 1060 – Hydraulic Slip Ring
  - Pitch System
    - Change 624 – Mechanical / Electrical to Mechanical
    - Added 1061 – Battery Backup
    - Added 1062 – Pitch Controller
    - Added 1063 – Pitch Motor
    - Added 1064 – Pitch Gearbox
  - Rotor
    - Change 602 – Add Tip brake / Spoilers to the end.
    - Added 1065 – Coatings
  - Structures
    - Added 1066 – Ladders
    - Added 1067 – Climb Assist / Ladders
    - Added 1068 – Tower Filtration
    - Added 1069 – Lighting
    - Added 1070 – Hoist
    - Added 1076 – Corrosion Control
  - Added new system – Human Performance
    - Added 1071 – General
    - Added 1072 – Operator
    - Added 1073 – Maintenance
    - Added 1074 – Contractor
    - Added 1075 – Procedure Error
- *Appendix D* – Terms and Definitions
  - Added General subsection
    - Added – Revenue Meter
    - Added – Off-Taker
    - Added – Utility
    - Added – Plant
    - Added – Group
    - Added – Sub-Group

- Capacity and Generation subsection
  - Added – Turbine Net Maximum Capacity (TNMC)
  - Added – Net Dependable Energy (NDE)
- Turbine States and Hours Collection
  - Clarified the Reserve Shutdown Definition
  - Moved examples to the appendix
- Equivalent Hours
  - Defined Equivalent Hours
  - Added – Equivalent Forced Derated Turbine Hours (EFDTH)
  - Added – Equivalent Maintenance Derated Turbine Hours (EMDTH)
  - Added – Equivalent Planned Derated Turbine Hours (EPDTH)
- Delays
  - Defined Delay Hours
  - Added – Forced Delay Turbine Hours (FDTH)
  - Added – Maintenance Delay Turbine Hours (MDTH)
  - Added – Planned Delay Turbine Hours (PDTH)
- Updated Figures D2 and D3
- Added Figure D4 – Cross Reference Chart

- *Appendix E* – Performance Equations
  - Modified equations for equivalent hour derates
  - Added the word Pooled and the letter P to each of the pooled equations.
  - Corrected equations 3.B.8 to 3.B.12 and 4.B.8 to 4.B.12. Added RUTH to the denominator.
- *Appendix F* – Manufacturers
  - Changed the title to Reference Tables
  - Moved tables from the body to appendix
- *Appendix H* – Examples
  - Changed the title to Outage Classification Guidelines
  - Added a section on General Considerations
  - Updated the entire section with categories of events with general principles.
- *Appendix I* – Overlapping Events
- *Appendix J* – Data Submittal Quality Checks, *Appendix K* – Frequently Asked Questions
  - Rate versus factor
  - Equivalent hours
  - Weighting methods