PJM Manual 22:

Generator Resource Performance Indices

Revision: 18

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Prepared by
Resource Adequacy Planning

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Approval

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Current Revision

Revision 18 (03/26/2020):

Periodic Review to include:

- Removed EEI from the acronym list (Section 1)
- Removed the definition of Demand Hours (Section 2.1)
- Refined the definition of f-factor (Section 2.1)
- Removed references to retired PJM committees and subcommittees (Section 3)
- Amended the first note (Section 3)
- Added a second clarifying note (Section 3)

Introduction

Welcome to the *PJM Manual for Generator Resource Performance Indices.* In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*").
- How to use this manual (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services
- Miscellaneous

About This Manual

The *PJM Manual for Generator Resource Performance Indices* is one of a series of manuals within the Reserve group. This manual focuses on data definitions and determinations concerning the past history and future projection of generating unit performance, as required for Planning and Market studies and also for other data required for specific planning applications.

The *PJM Manual for Generator Resource Performance Indices* consists of three sections. These sections are listed in the table of contents beginning on page 2.

Intended Audience

The intended audiences for the PJM Manual for Generator Resource Performance Indices are:

- PJM Board of Managers – The PJM Board Members are responsible for the administration and approval of the forecast obligation and techniques for determination.
- PJM Reliability Committee – Reliability Committee members are responsible for the review and submittal of the obligations with review of the PJM Board of Managers.
- PJM system planning staff – PJM staff are responsible for the calculation and submittal for approval of the installed reserve requirement, pool forced outage rate, forecast pool requirement, weather normalized coincident zonal peaks, peak period available ALM, and the PJM ALM Factor. These quantities are required to meet the RAA mandate of establishment of these quantities for applicable future planning periods.

- Other PJM Agreement signatory staff – The staff are responsible for supplying load and generator data in the required format and time period to assist in the calculation and submittal of required quantities.
- PJM audit staff – Auditors are responsible for ensuring Agreements of PJM Interconnection, L.L.C. are fair and consistent among the parties.
- PJM marketing services staff – PJM Marketing Services staff are responsible for monthly billing and maintenance of the accounted-for input data.

References

There are several references that provide background and details:

- PJM Operating Agreement
- PJM Open Access Transmission Tariff
- Reliability Assurance Agreement
- PJM Manual for: Generator Operational Requirements (M-14D)
- PJM Manual for: PJM Capacity Market (M-18)
- PJM Manual for: Load Forecasting and Analysis (M-19)
- PJM Manual for: PJM Resource Adequacy Analysis (M-20)
- PJM Manual for: Rules and Procedures for Determination of Generating Capability (M-21)
- PJM Manual for: Billing (M-29)
- IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity - IEEE Std 762-2006
- NERC Generating Availability Data System (GADS) Data Reporting Instructions

PJM Manual for Generator Resource Performance Indices does not replace any information in the reference documents. The reference documents are the primary source for specific requirements and implementation details.

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this PJM manual. We start each section with an overview. Then, we present details and procedures or references to procedures found in other PJM manuals. The following provides an orientation to this manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions

- A section at the end detailing all previous revisions of the PJM Manual

Section 1: Acronyms

1.1 Acronym Listing

AH	Available Hours
EAF	Equivalent Availability Factor
$EEFOR_d$	Effective Equivalent Demand Forced Outage Rate
EFOF	Equivalent Forced Outage Factor
EFOH	Equivalent Forced Outage Hours
$EFOR_d$	Equivalent Demand Forced Outage Rate
EFDH	Equivalent Forced Derated Hours
EMOF	Equivalent Maintenance Outage Factor
EMOH	Equivalent Maintenance Outage Hours
EMDH	Equivalent Maintenance Derated Hours
EPOEF	Equivalent Planned Outage Extension Factor
EPOF	Equivalent Planned Outage Factor
EPOH	Equivalent Planned Outage Hours
EPDH	Equivalent Planned Derated Hours
f_f	full f-factor
FOH	Forced Outage Hours
FOR	Forced Outage Rate
f_p	partial f-factor
FDH	Forced Derated Hours
GADS	Generator Availability Data System
GEBGE	General Electric, Baltimore Gas & Electric Reliability Program
GORP	Generator Outage Rate Program - This is a retired legacy program that has been replaced by an eGADS report entitled GORP.
IEEE	Institute of Electrical and Electronic Engineers
MOF	Maintenance Outage Factor
MOH	Maintenance Outage Hours

MDH	Maintenance Derated Hours
NERC	North American Electric Reliability Council
OAF	Operating Availability Factor
OC	PJM Operating Committee
PC	PJM Planning Committee
PH	Period Hours
POF	Planned Outage Factor
POH	Planned Outage Hours
PDH	Planned Derated Hours
PRISM	Probabilistic Reliability Index Study Model
RAAS	Resource Adequacy Analysis Subcommittee
RSH	Reserve Shutdown Hours
SH	Service Hours
SOF	Scheduled Outage Factor
UOH	Unplanned Outage Hours

Section 2: Definitions

2.1 Definitions

TERM	DEFINITION
Available Hours	The time a unit is capable of producing energy, regardless of its capacity level.
Deactivated Shutdown	The classification of a unit that is unavailable for service for an extended period of time for reasons not related to the equipment.
Effective Equivalent Demand Forced Outage Rate	The forced outage rate used for reliability and reserve margin calculations. (Refer to Equation 8.)
EPOEF	The ratio of EPOF (with SE's included) to EPOF (with SE's excluded).
Equivalent Availability Factor	The fraction of a given operating period in which a generating unit is available without any outages or equipment deratings. (Refer to Equation 7.)
Equivalent Demand Forced Outage Rate	The portion of time a unit is in demand, but is unavailable due to forced outages or deratings. (Refer to Equation 2.)
Equivalent Forced Outage Factor	The fraction of a given period in which a generating unit is not available due to forced outages and forced deratings. (Refer to Equation 3.)
Equivalent Maintenance Outage Factor	The fraction of a given period in which a generating unit is not available due to maintenance outages and maintenance deratings. (Refer to Equation 4.)
Equivalent Outage Hours	The number of hours a unit was involved in an outage or derating, expressed as equivalent hours of outage at its monthly net dependable capacity. Equivalent outage hours can be calculated for forced, maintenance, or planned outages and deratings. (Refer to Equation 1.)
Equivalent Planned Outage Factor	The fraction of a given period in which a generating unit is not available due to planned outages and planned deratings. (Refer to Equation 5.)
Equivalent Scheduled Outage Factor	The planned outage rate used for reliability and reserve margin calculations. (Refer to Equation 9.)
f-factor	Factors which scale the total number of forced outage hours to reflect those which occur when the unit is in demand by the operating system. Separate factors exist to adjust both outage (f_f) and derated (f_p) hours. (Refer to Equation 10.) These factors are delineated in IEEE STD 762-2006.

TERM	DEFINITION
Forced Outage	A complete reduction in the capability of a generating unit due to a failure that cannot be postponed beyond the end of the next weekend.
Forced Derating	A partial reduction in the capability of a generating unit due to a failure that cannot be postponed beyond the end of the next weekend
Future Unit	A unit to be placed in service at some future time, as indicated in RTEP.
GORP	Generator Outage Rate Program – This is a retired legacy program that has been replaced by an eGADS report entitled GORP.
Immature Unit	A unit having between zero and five full calendar years of operating experience for reliability calculations.
Inactive Reserve	The classification of a unit which is unavailable for service, but can be brought back into service in a relatively short period of time, typically measured in days. The PJM eGADS system requires that an IR event be a minimum of 3 months.
Maintenance Outage	A complete reduction in the capability of a generating unit, scheduled in advance with the approval of PJM, in order to perform necessary repairs on specific components of the facility that can be postponed beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage.
Maintenance Derating	A partial reduction in the capability of a generating unit, scheduled in advance with the approval of PJM, in order to perform necessary repairs on specific components of the facility that can be postponed beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage.
Mature Unit	A unit having at least five full calendar years of operating experience
Mothballed	The classification of a unit that is unavailable for service, but can be brought back into service with the appropriate amount of notification, typically weeks or months. The PJM eGADS system requires that a MB event be a minimum of 6 months in duration. A detailed explanation of the mothballed procedure can be found in PJM Manual 14D, Section 9.
Non-curtailing Outage	The removal from service of spare or redundant equipment (i.e., major components or entire systems) for repairs which causes no outage or derating in a generators capability.

TERM	DEFINITION
Operating Availability Factor	The portion of time a unit is available to operate.
Period Hours	The total clock time in the period of concern.
Planned Outage	A complete reduction in the capability of a generating unit, scheduled in advance, for inspection, maintenance or repair with approval of PJM.
Planned Derating	A partial reduction in the capability of a generating unit, scheduled in advance, for inspection, maintenance or repair with approval of PJM.
Reserve Shutdown Hours	The time a unit is available for service but not dispatched due to economics or other reasons.
Retired	The classification of a unit that is unavailable for service and not expected to return to service in the future. A detailed explanation of the retirement procedure can be found in PJM Manual 14D, Section 9
RTEP	Regional Transmission Expansion Plan
Service Hours	The time a unit is electrically connected to the system.
Variance	A measure of the variability of a unit's forced deratings which is used in reserve margin calculations.

Section 3: Equations and Derivations

The use of these equations and derivations is dependent upon the timely reporting of Generator Availability Data System (GADS) events and performance measures. The unit $EFOR_d$ will be 100% for any month of operation during which minimum reporting requirements are not met.

3.1 Equations

(1) Equivalent Outage Hours: The following equation is applicable to forced, maintenance and planned outages and deratings.

$$E = \sum_i \left(\frac{(D_i * T_i)}{C_i} \right)$$

Where:

E = equivalent outage hours,

D_i = capacity deration for event i, MW,

T_i = time accumulated during event i, hours, and

C_i = unit monthly net dependable capacity at the time of this event, MW

Note:
The unit monthly net dependable capacity can change if the outage extends over 1 or more months.

Also, in cases where the generator is experiencing a complete loss of capability (i.e. a full outage) $D_i = C_i$

(2) Equivalent Demand Forced Outage Rate:

$$EFOR_d(\%) = \left(\frac{(f_f * FOH + f_p * EFDH)}{SH + f_f * FOH} \right) * 100\%$$
$$Note: EFDH = EFOH - FOH$$

(3) Equivalent Forced Outage Factor:

$$EFOF(\%) = \left(\frac{EFOH}{PH} \right) * 100\% = \left(\frac{FOH + EFDH}{PH} \right) * 100\%$$
$$Note: EFDH = EFOH - FOH$$
$$or$$
$$EFOF(weeks/year) = \left(\frac{EFOH}{PH} \right) * \left(\frac{PH}{n * 168} \right)$$

Where, n is the number of years of accumulated outage hours.

(4) Equivalent Maintenance Outage Factor:

$$EMOF(\%) = \left(\frac{EMOH}{PH} \right) * 100\% = \left(\frac{MOH + EMDH}{PH} \right) * 100\%$$
$$Note: EMDH = EMOH - MOH$$
$$or$$
$$EMOF(weeks/year) = \left(\frac{EMOH}{PH} \right) * \left(\frac{PH}{n * 168} \right)$$

Where, n is the number of years of accumulated outage hours.

(5) Equivalent Planned Outage Factor:

$$EPOF(\%) = \left(\frac{EPOH}{PH} \right) * 100\% = \left(\frac{POH+EPDH}{PH} \right) * 100\%$$
$$Note: EPDH = EPOH - POH$$
$$or$$
$$EPOF(weeks/year) = \left(\frac{EPOH}{PH} \right) * \left(\frac{PH}{n*168} \right)$$

Where, n is the number of years of accumulated outage hours.

(6) Equivalent Planned Outage Extension Factor:

$$EPOEF = \left(\frac{EPOF(w/SEincluded)}{EPOF(w/SEexcluded)} \right)$$

(7) Equivalent Availability Factor:

$$EAF(\%) = \left(\frac{AH - \sum(EFDH + EMDH + EPDH)}{PH} \right) * 100\%$$

(8) Effective Equivalent Demand Forced Outage Rate:[1]

$$EEFOR_D(\%) = EFOR_D(\%) + \left(\frac{1}{4} \right) * EMOF(\%)$$

(9) Equivalent Scheduled Outage Factor:[1]

The equivalent scheduled outage factor can be expressed in either % or weeks/year using the equation:

$$ESOF = EPOF + \left(\frac{3}{4} \right) * EMOF$$

(10) f-factors: [2]

$$f_f = \left(\frac{1/r + 1/T}{1/r + 1/T + 1/D} \right)$$

Where:

$$r = average\ forced\ outage\ duration = \frac{FOH}{(number\ of\ forced\ outages)}$$

$$T = average\ time\ between\ calls\ for\ a\ unit\ to\ run = \frac{RSH}{(number\ of\ attempted\ starts)}$$

1 Since PRISM can only accommodate two outage rates, the maintenance outage factor must be allocated to one, or both, of these rates. A rationale for proportioning it as shown is contained in the document "Report on the Study of Load Models and Reliability Program Features," Section I GEBGE Options, (Random Maintenance), issued March, 1972 by the PJM Capacity and Transmission Planning Subcommittee. The original decision, presumably made by the PJM Planning and Engineering Committee, predates the indicated report.

2 Both the full and partial f-factors are delineated in IEEE STD 762-2006.

$$D = average\ run\ time = \frac{SH}{(number\ of\ successful\ starts)}$$

And

$$f_p = \left(\frac{SH}{AH} \right)$$

3.1.1 Data for Units with Five Full Calendar Years of Operating Experience

Individual Unit Effective Equivalent Demand Forced Outage Rate Calculation:
Included in the Effective Equivalent Demand Forced Outage Rate ($EEFOR_d$) calculation is the Equivalent Demand Forced outage rate ($EFOR_d$). Class Average Outage Rates for $EFOR_d$ will be used for any unit for which sufficient GADS data is not available. Class Average Outage Rates are posted on the PJM web site at http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx

- **Mature Unit:** The effective equivalent demand forced outage rate (%) of a mature unit is determined based on the latest five full calendar years of operating experience. It is calculated by adding 25% of the equivalent maintenance outage factor (%) to the equivalent demand forced outage rate. The five-year cumulative statistics are to be taken directly from the GORP report which has scheduled extensions included, unless manual adjustments are necessary.
- **Mothballed Status:** The classification of a unit which is unavailable for an extended period of time (minimum 6 months) because of its removal from operating service for either economic or non-equipment related reasons. For a unit to return from mothball status it must be succeeded by a planned or maintenance event in which repairs are made in order to allow it to return to service.
- **Combined Cycle Conversion of Existing CTs:** Combined Cycle units created by adding heat recovery boilers and steam turbines to existing combustion turbines will use Class Average Outage Rates until the combined cycle unit has mature operating history unless granted an exception.

Capacity Variance Calculation:

- **Mature Unit:** The capacity variance (MW^2) of a mature unit is calculated using the procedure given in Item E: Capacity Variance Calculation Procedure for Existing Units. This information is to be taken directly from the appropriate GORP report and used, unless manual adjustments are required.
- **Mothballed Status:** The classification of a unit which is unavailable for an extended period of time (minimum 6 months) because of its removal from operating service for either economic or non-equipment related reasons. For a unit to return from mothball status it must be succeeded by a planned or maintenance event in which repairs are made in order to allow it to return to service.
- **Combined Cycle Conversion of Existing CTs:** Combined Cycle units created by adding heat recovery boilers and steam turbines to existing combustion turbines will use the following variance formula until the combined cycle unit has mature operating history unless granted an exception.

$$V = MW^2 * (1 - EEFOR_d) * EEFOR_d$$

Scheduled Outage Data Calculation:

- **Mature Unit:** The scheduled outage data of a mature unit is calculated based on the latest five full calendar years of operating experience. Ten years of scheduled outage weeks are determined for each unit by multiplying the forecast maintenance weeks by the EPOEF (equation 6) and adding to each 75% of the EMOF (weeks/year). The five-year cumulative statistics are to be taken directly from the appropriate GORP output and used, unless manual adjustments are necessary.

3.1.2 Data for Units with Less Than Five Full Calendar Years of Operating Experience and Future Units

Individual Unit Effective Equivalent Demand Forced Outage Rate Calculation:

Included in the Effective Equivalent Demand Forced Outage Rate ($EEFOR_d$) calculation is the Equivalent Demand Forced outage rate ($EFOR_d$).

Class Average values for $EFOR_d$ will be used for any unit for which sufficient GADS data is not available.

- **Immature Unit:** The effective equivalent demand forced outage rate of an immature unit is the weighted combination of its historical and class average rates (i.e., Class Average Outage Rates). For example, the rate for a unit with 'n' full calendar years of operating experience is:

$$EEFOR_d(\%) = \left(\frac{n * EEFOR_d(\%, historical) + (5 - n) * EEFOR_d(\%, Class\ Average Value)}{5} \right)$$

Where, $EEFOR_d$ (%, historical) must be manually calculated using Equations 2, 4 and 8 given in Section 3.

- **Future Unit:** The effective equivalent demand forced outage rate (%) of a future unit is the class average rate for its size and type indicated in Class Average values.
- **Combined Cycle Conversion of Existing CTs:** Combined Cycle units created by adding heat recovery boilers and steam turbines to existing combustion turbines will use Table III class average rates until the combined cycle unit has mature operating history unless granted an exception.

Capacity Variance Calculation:

- **Immature Unit:** The forced outage capacity variance of an immature unit is the weighted combination of its historical and future unit values. For example, the variance for a unit with 'n' full calendar years of operating experience is:

$$\sigma^2(MW^2) = \left(\frac{n * V_h(MW^2, historical) + (5 - n) * V_f(MW^2, future)}{5} \right)$$

Where, V_h, is calculated using the procedure given in Section V, Item E and V_f is the future unit variance appropriate for the unit's size and type indicated in the Class Average Outage Rates of this report.

- **Future Unit:** The capacity variance (MW^2) of a future unit is the value appropriate for the unit's size and type indicated in the Class Average Outage Rates of this report.
- **Combined Cycle Conversion of Existing CTs:** Combined Cycle units created by adding heat recovery boilers and steam turbines to existing combustion turbines will use the following variance formula until the combined cycle unit has mature operating history unless granted an exception.

$$V = MW^2 * (1 - EEFOR_d) * EEFOR_d$$

Scheduled Outage Data:

- **Immature Unit:** The scheduled outage data for an immature unit is comprised of the following components:
    - o The equivalent planned outage extension factor (EPOEF);
    - o The equivalent maintenance outage factor (EMOF) in weeks per year;
    - o Years of service; and
    - o The yearly calculation for scheduled outage data for a unit with 'n' full calendar years of operating experience is:

$$ScheduledOutage(yearly) = \left(\begin{array}{c} [((PlannedMain(wks/yr)*EPOEF) + (0.75*EMOF(wks/yr)))*n] \\ + [ClassAverageValueScheduledOutageWeeks(wks/yr) + \\ (0.75*EMOF(ClassAverageValue))]*(5-n) \end{array} \right) / 5$$

Where, EPOEF and EMOF (historical) must be manually calculated using Equations 6 and 4 respectively, as given in Section 3.

- **Future Unit:** The scheduled outage data of future units are assigned the appropriate class average values for scheduled outages and maintenance cycles indicated in the Class Average Outage Rates.
- **Combined Cycle Conversion of Existing CTs:** Combined Cycle units created by adding heat recovery boilers and steam turbines to existing combustion turbines will use the Class Average Outage Rates values until the combined cycle unit has mature operating history unless granted an exception.

Note:
In cases where immature units have data for something other than a full year, adjusting the formulae so calculations can use months of data is appropriate

3.2 Item A: Full f-Factor Derivation (*)

The following diagram illustrates the relationships between the potential states in which a generator can reside. The term governing the transition from one state to another is shown on the diagram adjacent to the line indicating the direction of the transition.

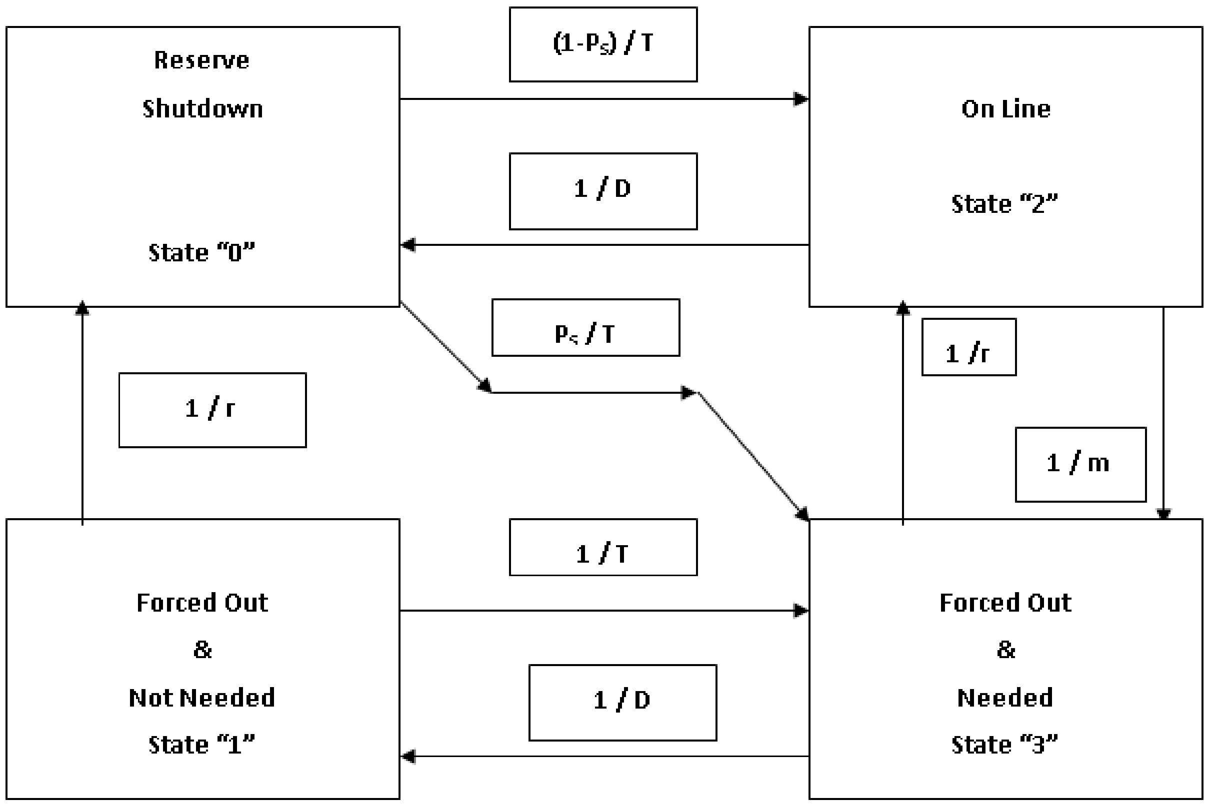

Exhibit 1: Generator States

(*) "A Four-State Model for Estimation of Outage Risk for Units in Peaking Service," Report of the IEEE Task Group on Models for Peaking Service Units, Application of Probability Methods Subcommittee, IEEE Transactions on Power Apparatus and Systems, March/April 1972.

Terms:

$$r = average\ forced\ outage\ duration$$

$$T = average\ time\ between\ calls\ for\ the\ unit\ to\ run$$

$$D = average\ run\ time\ during\ periods\ of\ demand$$

$$m = average\ run\ time\ between\ forced\ outages$$

$$P_S = probability\ of\ a\ start\ failure\ when\ the\ unit\ is\ called\ to\ run$$

On page 621 of the above referenced IEEE paper, the f-factor was defined for use as a mathematical trick to permit the substitution of known quantities for unknown quantities in the equation expressing the probability that a unit was unavailable during a demand period (equation 15). The known quantities were P_2 (the probability of being in service during a demand period; i.e., state 2) and P_1 + P_3 (the probabilities of being forced out during a demand period; i.e., states 1 and 3). Equation 15 is given as

$$P = \frac{P_3}{(P_2 + P_3)}$$

Define the f-factor as f = P_3 / (P_1 + P_3) and multiply both sides by the term (P_1 + P_3) to yield

$$P_3 = f^*(P_1 + P_3)$$

Now, substitute this equation into equation 15 to eliminate the lone P_3 term

$$P = \frac{f^*(P_1 + P_3)}{P_2 + f^*(P_1 + P_3)}$$

The known quantities of P_2 and P_1 + P_3, expressed in hours, are

$$P_2 = \frac{SH}{(AH + FOH)}$$

And

$$P_1 + P_3 = \frac{FOH}{(AH + FOH)}$$

Substituting these equations into the modified equation 15 given above yields

$$P = \frac{f^*FOH}{SH + f^*FOH}$$

from which we can see that the f-factor weights the forced outage hours to reflect only that portion which occur during periods of demand.

Because we still don't know how to separately define P_3, we need to redefine the f-factor in terms of data readily available from recorded outage statistics. Start by defining the frequency of being in state 1 as

$$\begin{aligned} F_1 &= P_1{}^*\text{rate of departure from state 1} \\ &= P_1{}^*\left(\frac{1}{r} + \frac{1}{T}\right) \end{aligned}$$

This can also be expressed as

$$\begin{aligned} F_1 &= P_3{}^*\text{rate of entry from state 3} \\ &= P_3{}^*\left(\frac{1}{D}\right) \end{aligned}$$

Equating these two expressions and solving for P_1 yields

$$P_1 = P_3{}^*\left(\frac{\frac{1}{D}}{\frac{1}{r} + \frac{1}{T}}\right)$$

Substituting this equation into the f-factor definition yields the expression

$$f_f = \frac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}}$$

which can be determined from the outage data statistics. This factor is designated as the full f-factor (f_f) because it is used to weight the full forced outage hours.

3.3 Item B: Partial f-Factor Derivation

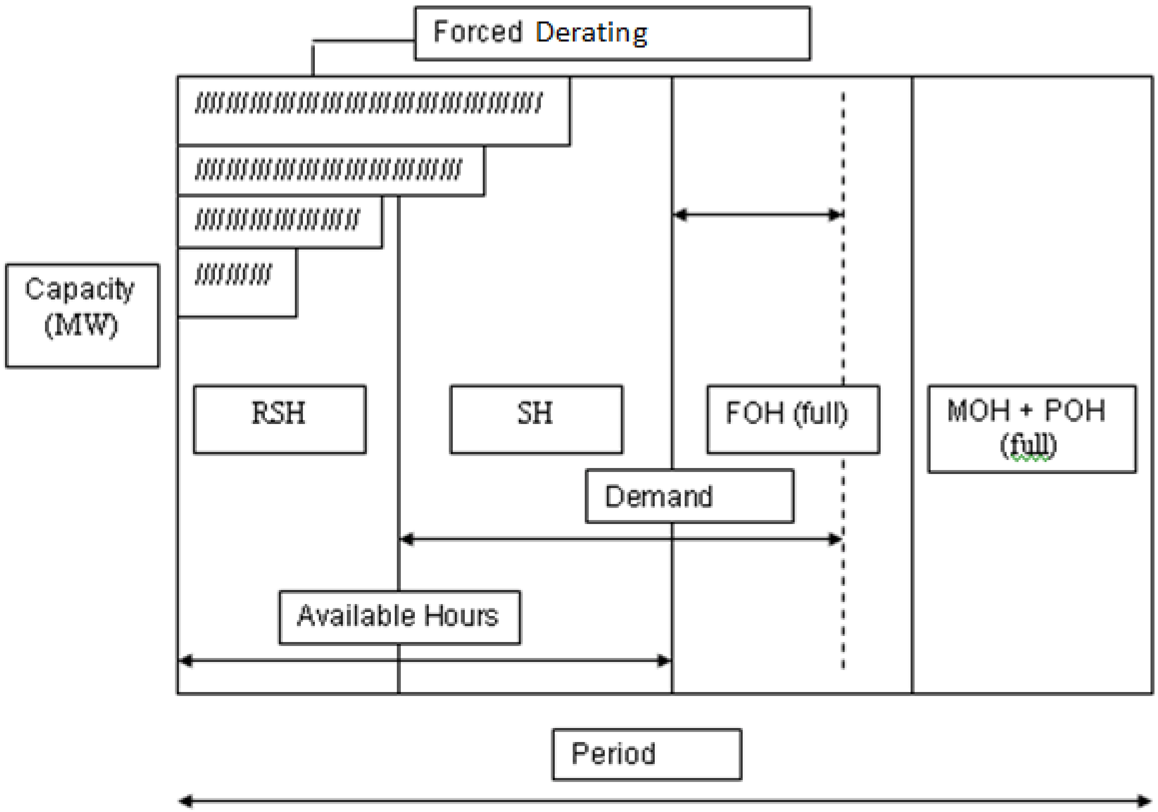

Exhibit 2: Partial f-Factor Time Period

The partial f-factor is a measure of the equivalent full forced outage hours that occur during times of demand. Theoretically, the partial f-factor is the ratio of the equivalent forced partial outage hours occurring during demand periods to the total equivalent forced partial outage hours. Assuming that the partial outages are distributed similarly during service hours and reserve shutdown hours, then the partial f-factor can be expressed as the ratio of service hours to the summation of service and reserve shutdown hours. Since available hours equals the summation of service and reserve shutdown hours, the partial f-factor can be expressed as the ratio of service hours to available hours, or

$$f_p = \frac{SH}{AH}$$

3.4 Item C: Modified Two-State Model for Reliability Calculations

The standard two-state model of a generator considers the unit as being either fully available or fully unavailable. The modified two-state model is a better representation for reliability calculations because it considers the distribution of outage states possible for a generator. The result of using the modified two-state generator availability model is a reduction in the amount of reserve capacity required to maintain a reliability index of 10 years per day, as compared to the reserve requirement determined using the standard model.

The standard two-state model calculates the mean available capacity as

$$\mu = (1 - EEFOR_d) * C$$

Where:

$$\mu = mean capacity, MW$$

$$C = unit's net summer installed capacity, MW, and$$

$$EEFOR_D = unit's effective equivalent demand forced outage rate, per-unit$$

The implied capacity variance about the mean with the standard two-state model is

$$\sigma^2 = (1 - EEFOR_d) * EEFOR_d * C^2$$

Where:

$$\sigma^2 = variance, MW^2$$

This is the maximum variance that can be experienced about the mean with the given effective equivalent demand forced outage rate. Any representation of partial outage states will tend to lower the variance.

The modified two-state model preserves both the mean and the variance of the original forced outage distribution by simultaneously solving the two-state mean and variance equations for unit capacity and effective equivalent demand forced outage rate using the two-state mean and variance values. The resulting modified two-state equations are:

$$C' = \frac{\mu}{1 - EEFOR_d'}$$

And

$$EEFOR_d' = \frac{\sigma^2}{\mu^2 + \sigma^2}$$

Where:

$$C' = modified two-state unit net capacity, MW, and$$

$$EEFOR_d' = modified two-state EEFOR_d, per-unit$$

3.5 Item D: Rules for Consistency of Generator Outage Rate Calculations

1. Any errors or inconsistencies found in the PJM Outage Data History File must be corrected.
    a. All revisions to outage rates, for reasons of data integrity, must be accomplished by revising the PJM GADS database via the PJM eGADS Tool.

2. Any outages due to natural disasters (e.g., 1972 Agnes Flood), which PJM determines to have a low probability of recurrence, can be eliminated from the outage history when calculating outage rates for use in forecasting. These special events are identified in the PJM eGADS Tool.

3.6 Item E: Capacity Variance Calculation Procedure for Existing Units

The capacity variance is one of the inputs to the PRISM program which is used to determine the PJM capacity reserve requirement. Theoretically, the capacity variance of a unit is calculated using the equations

$$\mu = \sum_{i=1}^{n} (C_i * P_i)$$

$$C_i = (1 - D_i) * C$$

And

$$\sigma^2 = \sum_{i=1}^{n} (C_i - \mu)^2 * P_i$$

Where:

$$\mu = mean, MW,$$

$$n = number\ of\ states,$$

$$C_i = capacity\ available\ at\ state\ i, MW,$$

$$P_i = probability\ of\ being\ in\ (i.e., the\ outage\ rate\ for)\ state\ i, per\text{-}unit$$

$$D_i = per\text{-}unit\ capacity\ deration\ at\ state\ i,$$

$$C = net\ summer\ installed\ capacity, MW, and$$

$$\sigma^2 = variance, (MW)^2$$

However, to utilize the information readily available in the outage statistics, a somewhat modified approach has been taken. For PJM reliability calculations, the effective equivalent demand forced outage rate represents the mean per unit unavailability. Therefore, the mean capacity can be expressed as

$$\mu = (1 - EEFOR_d) * C$$

Since the EEFOR includes 25% of the equivalent maintenance outage time, it is a measure of the unit's unavailability due to all unplanned outages. Therefore, the derated state probabilities must be based on the total unplanned outage time spent in each state. A maintenance f-factor has been introduced to transform the maintenance outage time from a period hour to a demand hour basis so it can be added to the forced outage time. The maintenance f-factor, which also included the 25% proportioning, is defined as

$$f_m = \frac{SH + f_f * FOH}{4 * PH} = \frac{DH}{4 * PH}$$

The total forced and maintenance outage time spent in each state is:

$$100\%\ forced\ out\ state(100\%\ out) H_{100} = f_f * FOH + f_m * MOH$$

$$forced\ derated\ state(i\% out) H_i = f_p * FDH_i + f_m * MDH_i$$

$$100\%\ available\ state\ (0\%\ out) H_0 = DH - H_{100} - \sum H_i$$

The probability of being in each state is simply the ratio of the time spent in each state to the total time, or

$$P_0 = \frac{H_0}{DH}$$

$$P_{100} = \frac{H_{100}}{DH}$$

$$P_i = \frac{H_i}{DH}$$

The individual state variances can now be calculated using the equation

$$\sigma^2 = \sum_{i=0}^{100} ((1 - D_i) * C - \mu)^2 * P_i$$

Where:

$$D_i = per\text{-}unit\ average\ unavailability\ of\ state\ i,$$

$$C = unit\ net\ summer\ installed\ capacity, MW,$$

$$\mu = mean\ capacity, MW, calculated\ using\ the\ unit's EEFOR$$

$$P_i = per\text{-}unit\ probability\ of\ being\ in\ state\ i$$

This procedure has been incorporated into the Generator Outage Rate Program (GORP) and is used to produce the information displayed in the "Implied Capacity Variance field."

Future Unit Variance

Variance values for future fossil and nuclear units were determined by examining the historical statistics for each unit type. A scatter diagram of the unit equivalent forced capacity C_f was plotted against the square root of variance to yield the following equations:

Fossil Steam Unit Variance

$$(V_F)^{.5} = 1.1 * C_f + 40$$

OR

$$V_F = (1.1 * C_f + 40)^2$$

Nuclear Unit Variance

$$(V_N)^{.5} = 0.8 * C_f + 140$$

OR

$$V_N = (0.8 * C_f + 140)^2$$

Where:

$$V_F = fossil\ \ unit\ \ variance$$

$$V_N = nuclear\ \ unit\ \ variance$$

$$C_f = unit\ \ capacity\ \ X\ \ unit\ \ EEFOR_d$$

Variance values for future internal combustion, combined cycle and hydro units were determined using the standard two-state model calculation:

Internal Combustion, Combined Cycle and Hydro Unit Variance

$$V = (\ 1 - EEFOR_d\ ) * EEFOR_d * C^2$$

Where:

$$V = Unit\ \ Variance$$

$$C = Unit\ \ Capacity$$

Revision History

Revision 17 (4/1/2017):

- Cover-to-Cover Periodic Review
- Changed terms of partial outage hours to derated hours for forced, maintenance and planned events.

Revision 16 (11/16/2011):

- General cleanup and checking the compatibility of all acronyms and definitions between PJM Manuals.

Revision 15 (06/01/2007):

- Revisions for the implementation of the Reliability Pricing Model and general clean-up.

Revision 14 (06/01/2005):

- Updated Exhibit 1 to include new PJM Manuals.
- Removed all references to the Planning Study Outage Data Report which was a report under the former Installed Capacity Accounting construct and revised commentary on derivations accordingly. Removed all reference to the Generator Unavailability Subcommittee and the PJM Class Average Outage Rates and added link to table of NERC-based Class Average values now on PJM web site

Revision 13 (05/01/2004):

- Changed name of Manual; removed references to Generator Unavailability Subcommittee (addressed under PJM Members Handbook); revised Class Average Outage Rate table

Revision 12 (08/23/2000):

- Modified text to refer to "Class Average Outage Rates" instead of "Table III". Reviewed for compliance with RAA.

Revision 11 (06/01/1999):

- Removed all references to Supplemental Agreement, removed references to data and procedures no longer supported and reformatted document for publishing on the PJM website.

Revision 10 (04/01/1996)

Revision 09 (11/01/1994)

Revision 08 (10/01/1994)

Revision 07 (07/01/1994)

Revision 06 (02/01/1993)

Revision 05 (09/01/1992)

Revision 04 (12/01/1991)

Revision 03 (03/01/1987)

Revision 02 (05/01/1986)

Revision 01 (02/01/1985)

Revision 00 Issued (04/01/1984)