



Working to Perfect the Flow of Energy

PJM Manual 22:

Generator Resource Performance Indices

Revision: 15

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Prepared by

Capacity Adequacy Planning

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PJM Manual 22

Generator Resource Performance Indices

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Approval

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Thomas Falin, Manager
Capacity Adequacy Planning

Current Revision

Revision 15 (06/01/07)

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

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 PJM set of manuals. This manual focuses on data definitions and determinations concerning the past history and future projection of generating unit performance, as required for PJM Reliability and Capacity Allocation 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 ii.

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 – MAAC Control Zone
- Reliability Assurance Agreement – PJM West Region
- PJM Manual for: [Capacity Obligations \(M-18\)](#)
- PJM Manual for: [Load Data Systems \(M-19\)](#)
- PJM Manual for: [PJM Reserve Requirements \(M-20\)](#)
- PJM Manual for: [Rules and Procedures for Determination of Generating Capability \(M-21\)](#)
- PJM Manual for: [PJM eGADS \(M-23\)](#)
- PJM Manual for: [PJM eCapacity \(M-24\)](#)
- PJM Manual for: [Billing \(M-29\)](#)
- PJM Manual for: [Definitions and Acronyms \(M-35\)](#)
- IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity - IEEE Std 762-2005(R2002)
- 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



Because we believe that explaining concepts is just as important as presenting the procedures, we start each section with an overview. Then, we present details and procedures. This philosophy is reflected in the way we organize the material in this manual. 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

Acronym Listing

AH	Available Hours
EAF	Equivalent Availability Factor
EEFOR _D	Effective Equivalent Demand Forced Outage Rate
EEl	Edison Electric Institute
EFOF	Equivalent Forced Outage Factor
EFOH	Equivalent Full Forced Outage Hours
EFOR _D	Equivalent Demand Forced Outage Rate
EFPOH	Equivalent Forced Partial Outage Hours
EMOF	Equivalent Maintenance Outage Factor
EMOH	Equivalent Full Maintenance Outage Hours
EMPOH	Equivalent Maintenance Partial Outage Hours
EPOEF	Equivalent Planned Outage Extension Factor
EPOF	Equivalent Planned Outage Factor
EPOH	Equivalent Full Planned Outage Hours
EPPOH	Equivalent Planned Partial Outage Hours
f_f	full f-factor
FOH	Full Forced Outage Hours
FOR	Forced Outage Rate
f_p	partial f-factor
FPOH	Forced Partial Outage Hours
GADS	Generating Availability Data System
GEBGE	General Electric, Baltimore Gas & Electric Reliability Program
GORP	Generator Outage Rate Program



GUS	PJM Generator Unavailability Subcommittee
GUSOUT	Synonym for GORP
IEEE	Institute of Electrical and Electronic Engineers
L&CS	PJM Load and Capacity Subcommittee
MOF	Maintenance Outage Factor
MOH	Full Maintenance Outage Hours
MPOH	Maintenance Partial Outage 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	Full Planned Outage Hours
PPOH	Planned Partial Outage Hours
PRISM	Probabilistic Reliability Index Study Model
RSH	Reserve Shutdown Hours
SH	Service Hours
SOF	Scheduled Outage Factor
UOH	Unplanned Outage Hours

Section 2: Definitions

Definitions

Available Hours	The time a unit is capable of producing energy, regardless of its capacity level.
Demand Hours	The time interval each day on a particular system in which there is a heavy demand for electricity. For PJM, it is the time period beginning 8:00:01 and ending 22:00:00, inclusive.
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 portion of time a unit is available to operate, recognizing equivalent partial outage time. (Refer to Equation 7.)
Equivalent Demand Forced Outage Rate	The portion of time a unit is in demand, but is unavailable due to a forced outage. (Refer to Equation 2.)
Equivalent Forced Outage Factor	The portion of time a unit is unavailable due to forced outages. (Refer to Equation 3.)
Equivalent Maintenance Outage Factor	The portion of time a unit is unavailable due to maintenance outages. (Refer to Equation 4.)
Equivalent Outage Hours	The number of hours a unit was involved in an outage, expressed as equivalent hours of full outage at its maximum net dependable capacity. Equivalent hours can be calculated for forced, maintenance, or planned outages. Overlapping partial outage hours are not permitted in PJM outage rate calculations and overlaps are eliminated according to an outage type hierarchy. (Refer to Equation 1.)
Equivalent Planned Outage Factor	The portion of time a unit is unavailable due to planned outages. (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 have been adopted by PJM to scale the total number of forced outage hours to reflect those which occur during demand hours. Separate factors exist to adjust full (f_f) and partial (f_p) outage hours. (Refer to Equation 10.)
Forced Outage	An outage 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 a forecast installed capacity schedule.
GORP	Generator Outage Rate Program
Immature Unit	A unit having between zero and five full calendar years of operating experience.
Inactive Status	The classification of a unit which is unavailable for an extended period of time because of its removal from both operating service and installed capacity for either economic or non-equipment related reasons.
Maintenance Outage	An outage that can be postponed beyond the end of the next weekend, but requires the unit be removed before the next planned outage.
Mature Unit	A unit having at least five full calendar years of operating experience
Mothballed Unit	A unit placed on inactive status.
Non-curtailing Outage	The removal from service of spare or redundant equipment (i.e., major components or entire systems) for repairs which causes no unit outage or capacity reduction.
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	An outage of predetermined length that is scheduled well in advance of its occurrence. The outage must be included in a regularly issued maintenance schedule at least one month prior to the starting date of the outage; i.e., the outage must appear in two consecutive issues of the PJM Unit Maintenance Schedule prior to starting the outage.



Planning Period	The continuous time period beginning 00:00: 01 on June 1 of a given year and ending 24:00: 00 on May 31 of the following year.
Reserve Shutdown Hours	The time a unit is available for service but not dispatched due to economics or other reasons.
Service Hours	The time a unit is electrically connected to the system.
Variance	A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations.

Section 3: Equations and Derivations

NOTE:

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.

Equations

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

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

where:

E = equivalent outage hours,

D_i = capacity duration for outage i , MW,

T_i = time accumulated during outage i , hours, and

C_i = unit maximum net dependable capacity at the time of this outage, MW

NOTE: The capacity can change if the outage extends over 1 or more months.

(2) Equivalent Demand Forced Outage Rate:

$$EFOR_D (\%) = \left(\frac{(f_f * FOH + f_p * EFPOH)}{SH + f_f * FOH} \right) * 100\%$$

Note : $EFPOH = EFOH - FOH$

(3) Equivalent Forced Outage Factor:

$$EFOF (\%) = \left(\frac{EFOH}{PH} \right) * 100\% = \left(\frac{FOH + EFPOH}{PH} \right) * 100\%$$

$$\text{Note : } EFPOH = EFOH - FOH$$

or

$$EFOF(\text{weeks / year}) = \left(\frac{EFOH}{PH} \right) * \left(\frac{PH}{n * 168} \right)$$

where n is the number of years of accumulated outage hours.

(4) Equivalent Maintenance Outage Factor:

$$EMOF (\%) = \left(\frac{EMOH}{PH} \right) * 100\% = \left(\frac{MOH + EMPOH}{PH} \right) * 100\%$$

$$\text{Note : } EMPOH = EMOH - MOH$$

or

$$EMOF(\text{weeks / year}) = \left(\frac{EMOH}{PH} \right) * \left(\frac{PH}{n * 168} \right)$$

where n is the number of years of accumulated outage hours.

(5) Equivalent Planned Outage Factor:

$$EPOF (\%) = \left(\frac{EPOH}{PH} \right) * 100\% = \left(\frac{POH + EPPOH}{PH} \right) * 100\%$$

$$\text{Note : } EPPOH = EPOH - POH$$

or

$$EPOF(\text{weeks / year}) = \left(\frac{EPOH}{PH} \right) * \left(\frac{PH}{n * 168} \right)$$

where n is the number of years of accumulated outage hours.

(6) Equivalent Planned Outage Extension Factor:

$$EPOEF = \left(\frac{EPOF (\text{w/SE included})}{EPOF (\text{w/SE excluded})} \right)$$

(7) Equivalent Availability Factor:

$$EAF (\%) = \left(\frac{AH - \sum (EFPOH + EMPOH + EPPOH)}{PH} \right) * 100\%$$

(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:

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

-
- (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.*

(10) f-factors:^(2,3)

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

where:

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

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

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

and

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

-
- (2) *The full f-factor was adopted for use by PJM with the acceptance of the "Report on Generating Unit Outage Definitions" issued in November, 1972 by the PJM Operating and P&E Committees. Refer to Section V, Item A, for the derivation of the full f-factor.*

- (3) The current definition of the partial f-factor was proposed by the Generator Unavailability Subcommittee, and approved for use by the Planning and Engineering Committee at its 260th meeting held March 8, 1982.

Data for Units with Five Full Calendar Years of Operating Experience

- (1) 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/res-adequacy/resource-reports.html> .

- a. **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 (with f-factor). The five-year cumulative statistics are to be taken directly from the GORP output which has scheduled extensions included, unless manual adjustments are necessary.
 - b. **Mothballed Unit:** Currently, a mothballed unit is treated as a Planned Outage until it is reactivated and included in the company's installed capacity.
 - c. **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.
- (2) Capacity Variance Calculation:
- a. **Mature Unit:** The capacity variance (MW²) 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 output and used, unless manual adjustments are required.
 - b. **Mothballed Unit:** Currently a mothballed unit is treated as a Planned Outage until it is reactivated and included in the company's installed capacity.
 - c. **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.

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

- (3) Scheduled Outage Data Calculation:

- d. **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.

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

(1) 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.

- e. **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:

$$EEFOR_D (\%) = \left(\frac{n * EEFOR_D (\%, historical) + (5 - n) * EEFOR_D (\%, Table III)}{5} \right)$$

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

- f. **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.
- g. **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.

(2) Capacity Variance Calculation:

- h. **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.

- i. **Future Unit:** The capacity variance (MW²) 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.

- j. **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.

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

(3) Scheduled Outage Data:

- a. **Immature Unit:** The scheduled outage data for an immature unit is comprised of the following components:

The equivalent planned outage extension factor (EPOEF);

The equivalent maintenance outage factor (EMOF) in weeks per year;

Years of service; and

The yearly calculation for scheduled outage data for a unit with 'n' full calendar years of operating experience is:

$$\text{Scheduled Outage (yearly)} = \left(\begin{aligned} & [((\text{Planned Main. (wks / yr)} * \text{EPOEF}) + (0.75 * \text{EMOF (wks / yr)})) * n] \\ & + [\text{Table 3 Scheduled Outage Weeks (wks/yr)} + (0.75 * \text{EMOF (Table 3)})] * (5 - n) \end{aligned} \right) / 5$$

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

- b. **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.
- c. **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.

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.

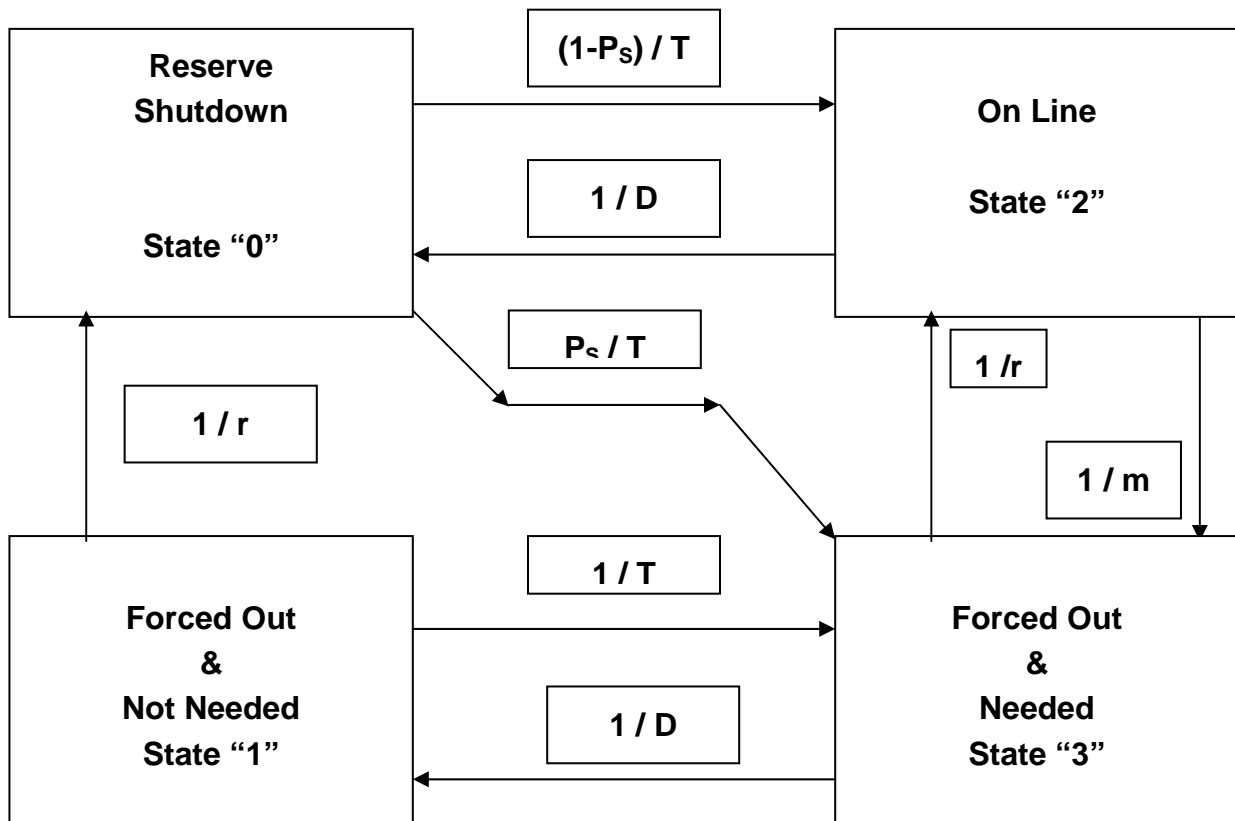


Exhibit 1: Generator States

(*) "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 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.

Item B: Partial f-Factor Derivation

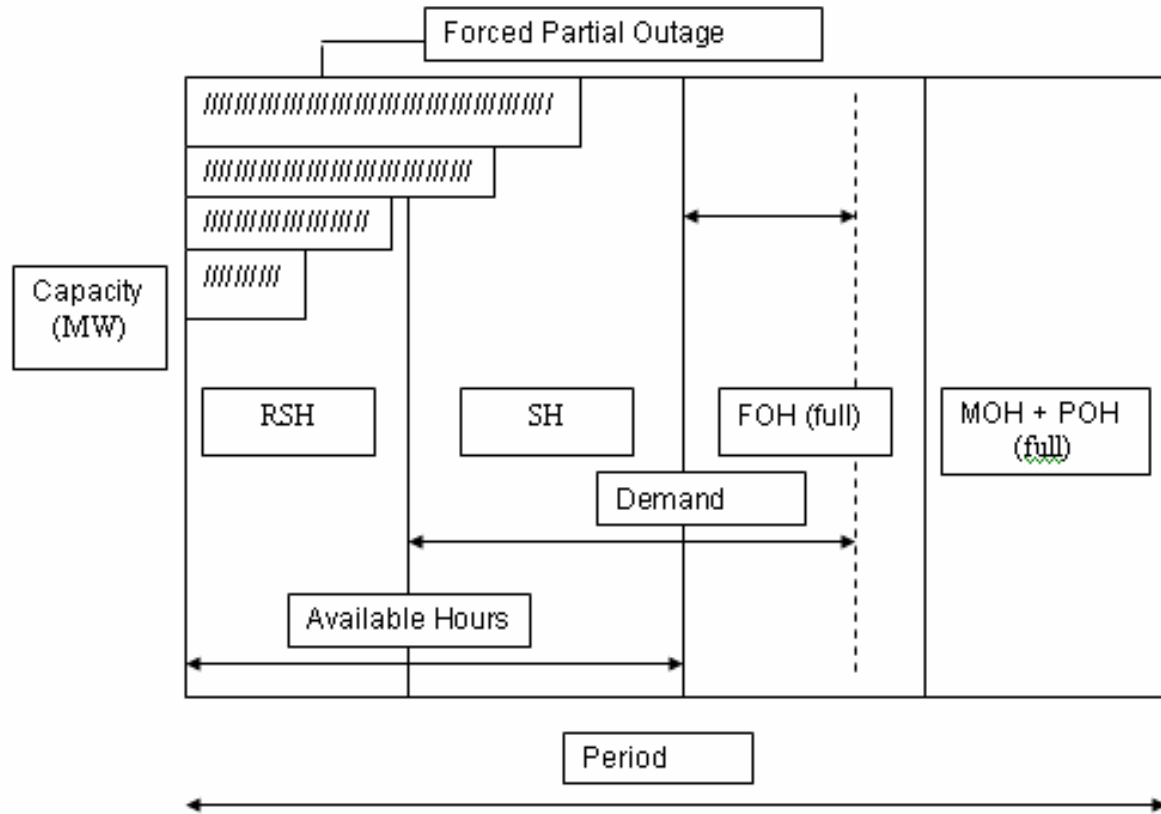


Exhibit 2: Partial f-Factor Time Period

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

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

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:

μ = 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:

$$\sigma^2 = \text{variance, MW}^2$$

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

$$EEFOR_D' = \text{modified two - state } EEFOR_D, \text{ per - unit}$$

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 Outage Data History File.
- (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 recorded in the GORP modification file.

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:

μ = 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 - unit

D_i = per - unit capacity deration at state i ,

C = net summer installed capacity, MW, and

* These rules were formulated by the Generator Unavailability Subcommittee, approved by the PJM Planning and Engineering Committee at its November, 1974 (172nd) meeting, and published in the December, 1974 GUS report to P&E titled "Forced Outage Rates and Unavailable Capability Due to Planned and Maintenance Outages for the PJM Supplemental Agreement."

$$\sigma^2 = \text{variance}, (MW)^2$$

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 partial outage 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:

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

$$\text{partial forced out state (i\% out)} \quad H_i = f_p * FPOH_i + f_m * MPOH_i$$

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

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

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

where:

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

$$C = \text{unit net summer installed capacity, MW,}$$

μ = mean capacity, MW, calculated using the unit's EEFOR

P_i = per - 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 "Unit Variance and Partial Outage State Report."

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 14 (06/01/05)

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 (05/01/04)

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 (06/01/99)

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 (04/01/96)

Revision 09 (11/01/94)

Revision 08 (10/01/94)

Revision 07 (07/01/94)

Revision 06 (02/01/93)

Revision 05 (09/01/92)

Revision 04 (12/01/91)

Revision 03 (03/01/87)

Revision 02 (05/01/86)

Revision 01 (02/01/85)

Revision 00 Issued (04/01/84)