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Section I

Scope of Responsibility

PJM PLANNING AND ENGINEERING COMMITTEE(*)
GENERATOR UNAVAILABILITY SUBCOMMITTEE
SCOPE OF RESPONSIBILITY

The PJM Generator Unavailability Subcommittee (GUS) is responsible to the PJM Planning and Engineering Committee (P&E) in all matters concerning the projection of generating unit unavailabilities, as required for PJM Reliability and Capacity Allocation studies. The Subcommittee shall also be responsible for other data required for specific planning applications.

To execute this charge, the Subcommittee shall develop and maintain unavailability rate definitions consistent with the purposes defined above. The Subcommittee shall also monitor and assess industry outage trends and tools to determine their utilization for PJM applications.

The Subcommittee is responsible for the preparation of two documents titled "Forced Outage Rates and Unavailable Capacity Due to Planned and Maintenance Outages for the PJM Supplemental Agreement" and "Forced Outage Rates and Scheduled Outage Data for Planning Studies." These documents provide data for Capacity Allocation and Reserve Requirement studies.

The Subcommittee shall also maintain, but will not be limited to, the PJM Generator Outage Rate Program (GORP) for historical data analysis.

Specific activities include:

(1) Update the "Report on Generating Unit Outage Definitions - Appendix B", as required.

(2) Update, annually, "Forced Outage Rates and Unavailable Capacity Due to Planned and Maintenance Outages for the PJM Supplemental Agreement" and "Forced Outage Rates and Scheduled Outage Data for Planning Studies."

(3) Provide projections of class average outage rates for new units.

(4) Monitor the industry for general trends and outage rate calculation tools.

(5) Provide miscellaneous reports and statistics required by other Committees/Subcommittees, e.g. "Production Cost Study Outage Rate Report."

(6) Recommend refinements in PJM outage data collection procedures, as required.

(7) Maintain the Generator Outage Rate Program for historical data analysis, and expand, as necessary, to fit other applications.

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(*) Excerpted from the November 28, 1978 letter to the Management Committee from S.C. Thomas, P&E Committee chairman, which transmitted revised Scopes of Responsibilities for all P&E committees.

## Section II

Acronyms

| | | |
|---|---|---|
| C&TPS | - | PJM Capacity and Transmission Planning Subcommittee |
| EEI | - | Edison Electric Institute |
| GADS | - | Generating Availability Data System |
| GCRPTF | - | PJM Generating Capability Rating Procedures Task Force |
| 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&CWG | - | PJM Load and Capacity Working Group |
| MC | - | PJM Management Committee |
| NERC | - | North American Electric Reliability Council |
| OC | - | PJM Operating Committee |
| PCTF | - | PJM Production Cost Task Force |
| P&E | - | PJM Planning and Engineering Committee |
| RMTF | - | PJM Reliability Methods Task Force |
| SRTF | - | PJM System Reliability Task Force |
| | | |
| FOR | - | Forced Outage Rate |
| $EFOR_D$ | - | Equivalent Demand Forced Outage Rate |
| $EEFOR_D$ | - | Effective Equivalent Demand Forced Outage Rate |
| EFOF | - | Equivalent Forced Outage Factor |
| MOF | - | Maintenance Outage Factor |
| EMOF | - | Equivalent Maintenance Outage Factor |
| POF | - | Planned Outage Factor |
| EPOF | - | Equivalent Planned Outage Factor |
| SOF | - | Scheduled Outage Factor |
| OAF | - | Operating Availability Factor |
| EAF | - | Equivalent Availability Factor |
| | | |
| AH | - | Available Hours |
| FOH | - | Full Forced Outage Hours |
| FPOH | - | Forced Partial Outage Hours |
| EFOH | - | Equivalent Full Forced Outage Hours |
| EFPOH | - | Equivalent Forced Partial Outage Hours |
| MOH | - | Full Maintenance Outage Hours |
| MPOH | - | Maintenance Partial Outage Hours |
| EMOH | - | Equivalent Full Maintenance Outage Hours |
| EMPOH | - | Equivalent Maintenance Partial Outage Hours |
| PH | - | Period Hours |
| POH | - | Full Planned Outage Hours |
| PPOH | - | Planned Partial Outage Hours |
| EPOH | - | Equivalent Full Planned Outage Hours |
| EPPOH | - | Equivalent Planned Partial Outage Hours |
| EPOEF | - | Equivalent Planned Outage Extension Factor |
| RSH | - | Reserve Shutdown Hours |
| SH | - | Service Hours |
| UOH | - | Unplanned Outage Hours |
| | | |
| $f_p$ | - | partial f-factor |
| $f_f$ | - | full f-factor |

# Section III
## Definitions and Equations

### Definitions

Forced Outage:
An outage that cannot be postponed beyond the end of the next weekend.

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.

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.

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.

Postponability Code 9 Outage:
A routine, periodic outage (e.g., deslagging, condenser cleaning, etc.) which both starts and ends during a single valley load period (i.e., the time period from 22:00:01 to 08:00:00, inclusive).

Deferred Maintenance:
The classification of forced outage time (full or partial) for a unit with repairs deferred for at least 90 days due solely to company financial constraints.

Period Hours:
The total clock time in the period of concern.

Service Hours:
The time a unit is electrically connected to the system.

Reserve Shutdown Hours:
The time a unit is available for service but not dispatched due to economics or other reasons.

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.

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, page 5.)

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, page 5.)

Section III

Definitions and Equations

Definitions (continued)

Equivalent Forced Outage Factor:
The portion of time a unit is unavailable due to forced outages. (Refer to Equation 3, page 5)

EPOEF:
The ratio of EPOF (with SE's included) to EPOF (with SE's excluded).

Equivalent Maintenance Outage Factor:
The portion of time a unit is unavailable due to maintenance outages. (Refer to Equation 4, page 5.)

Equivalent Planned Outage Factor:
The portion of time a unit is unavailable due to planned outages. (Refer to Equation 5, page 6.)

Operating Availability Factor:
The portion of time a unit is available to operate.

Equivalent Availability Factor:
The portion of time a unit is available to operate, recognizing equivalent partial outage time. (Refer to Equation 7, page 6.)

Effective Equivalent Demand Forced Outage Rate:
The forced outage rate used for reliability and reserve margin calculations. (Refer to Equation 8, page 6.)

Equivalent Scheduled Outage Factor:
The planned outage rate used for reliability and reserve margin calculations. (Refer to Equation 9, page 6.)

Variance:
A measure of the variability of a unit's partial forced outages which is used in reserve margin calculations. (Refer to Section V, Item E, page 35.)

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, page 6.)

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.

Mature Unit:
A unit having at least three full calendar years of operating experience for Supplemental Agreement usage or at least five full calendar years of operating experience for reliability calculations.

Immature Unit:
A unit having between zero and three full calendar years of operating experience for Supplemental Agreement usage or between zero and five full calendar years of operating experience for reliability calculations.

Future Unit:
A unit to be placed in service at some future time, as indicated in a forecast installed capacity schedule.

Section III

## Definitions and Equations

### Definitions (continued)

Inactive Status:
The classification of a unit which is unavailable for an extended period of time because of its removal from service for economic or non-equipment related reasons.

Mothballed Unit:
A unit placed on inactive status.

### Equations

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

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

where $E$ = equivalent outage hours,
$D_i$ = capacity deration 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:

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

Note:
EFPOH = EFOH - FOH

3. Equivalent Forced Outage Factor:

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

Note:
EFPOH = EFOH - FOH

or

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

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

4. Equivalent Maintenance Outage Factor:

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

Note:
EMPOH = EMOH - MOH

or

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

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

Section III

## Definitions and Equations

### Equations (continued)

5. Equivalent Planned Outage Factor:

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

Note: EPPOH = EPOH - POH

or

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

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

6. Equivalent Planned Outage Extension Factor:

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

7. Equivalent Availability Factor:

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

8. Effective Equivalent Demand Forced Outage Rate:[1]

$$EEFOR_D\ (\%) = EFOR_D\ (\%) + 1/4 * EMOF\ (\%)$$

9. Equivalent Scheduled Outage Factor:[1]
The equivalent scheduled outage factor can be expressed in either % or weeks/year using the equation

$$ESOF = EPOF + 3/4 * EMOF$$

10. f-factors:[2,3]

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

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

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

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

and

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

---

(1) Since GEBGE 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, pages 5-7 (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.

Section III

Definitions and Equations

Equations (continued)

(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, page 25 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.

11. Forced Outage Hour Adjustment for a Unit Partially on Deferred Maintenance:(*)

A unit with a forced partial outage classified as Deferred Maintenance for Economic Reasons will have its outage rate adjusted to exclude the deferred partial outage hours. The total equivalent forced partial outage hours in the latest 'n' full calendar years of operating experience will be reduced based on the deferred maintenance partial outage hours occurring within that window as given by the following equation:

$$EFPOH' = EFPOH - (1 - EFOR_{Dn}) * (PH_{DF} - OH_{DF}) * (MW_{RED}/MW_{RAT})$$

where:

- $EFPOH'$ = adjusted equivalent forced partial outage hours,
- $EFPOH$ = equivalent forced partial outage hours for the current 'n' year period,
- $EFOR_{Dn}$ = equivalent demand forced outage rate for the last 'n' full calendar years of history prior to the start of Deferred Maintenance (per-unit),
- $PH_{DF}$ = deferment period hours encompassed by the current 'n' year period
- $OH_{DF}$ = full forced, maintenance and planned outage hours that occur within the deferment period hours of the current 'n' year period,
- $MW_{RED}$ = amount of capacity on deferred maintenance (MW),
- $MW_{RAT}$ = unit net summer installed capacity rating (MW), and
- $n$ = appropriate number of calendar years:
  - 3 for reserve allocation usage, or
  - 5 for reliability (GEBGE) usage.

The following time line shows the relationships of the above outage hours:

```
|<--------------- Current Three Year Period for Contract --------------->|
|                                                                        |
|<----------- Equivalent Forced Partial Outage Hours (EFPOH) ----------->|
|                                                                        |
|<--- Remaining Deferment Period (PH) --->|                              |
|       ( Unit @ Reduced Capacity )       |   ( Unit @ Full Capacity )   |
|                                         |                              |
|     |<-- Full Outage Hours (OH) -->|    |                              |
|                                         |                              |
|<------------- Maximum OH -------------->|                              |
|          for EFPOH calculation          |                              |
```

NOTE: Refer to Section V, Item D for additional information.

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(*) A company can request that the portion of a forced outage event, associated with a deferral of repairs for a period of at least 90 days due solely to company financial constraints, be excluded from consideration as a forced outage. The PJM Operating Committee has the jurisdiction to act on such requests with advice from the Maintenance Committee and Interconnection Office. Requests are to be submitted in accordance with the "Revised Guideline for Classification of Extended Duration Outages Resulting from Voluntary Deferral of Repairs to Generating Units," as transmitted to the Operating Committee via letter from Mr. D.J. Pratzon dated June 15, 1979.

# Section IV
## Periodic Reports

### Introduction

The Generator Unavailability Subcommittee is required to periodically compile and issue several reports for use by other groups within PJM. These reports provide outage rate information needed to perform reliability, reserve requirement, allocation of forecast reserve requirement and production studies for the Interconnection. The names, scheduled due dates and recipients of these reports are:

| Report | Due Date | Recipient(s) |
|---|---|---|
| Preliminary Supplemental Agreement Outage Data Report (Tables I, Ia & II) | April 1 | P&E |
| Supplemental Agreement Outage Data Report | June 1 | P&E |
| Planning Study Outage Data Report (Final Table II) | October 1<br>February 15 | P&E, C&TPS, L&CWG |

Cover letters for these reports are to be addressed to the incumbent Planning and Engineering chairman. Copies of the cover letters and reports are to be sent to the GUS members.

## Section IV
## Periodic Reports

### Preliminary Supplemental Agreement Outage Data Report

Outage data, based on the latest three full calendar years of operating experience excluding I.O. code 9 outages (i.e., routinely occurring off-peak outages), is used in the PJM capacity allocation formula to determine each member company's capacity requirement. This data is provided to the PJM Planning & Engineering Committee for use in estimating new forecast reserve obligations. The report contains the weighted average equivalent demand forced outage rate and the total unavailable capacity due to planned and maintenance outages summarized by company for 10 consecutive planning periods starting June 1 of the current year.

The information provided in this report is preliminary for several reasons:

(1) The company forced outage rates are calculated using the latest available NERC/GADS outage data which may contain errors or inconsistencies at the time this report is due;
(2) The unavailable capacity due to forced outages are calculated using the latest available NERC/GADS forced outage hours which may contain errors or inconsistencies as the Preliminary report is due. Also, the capacity plans are subject to change after the issuance of this report.
(3) The unavailable capacity due to planned and maintenance outages is subject to capacity and current year maintenance schedule changes between the issuance of this report and the Supplemental Agreement Outage Data Report.

The report is organized as follows:

Transmittal Letter
Table I. PJM Company Average Equivalent Demand Forced Outage Rates
Table Ia. PJM Company Average Forced Unavailable Megawatts
Table II. PJM Company Planned and Maintenance Average Unavailable Megawatts

The information contained in these tables is determined using the procedures outlined in the "Supplemental Agreement Outage Data Report" and will not be repeated here.

Each company's representative is to breakdown the company EFOR for the planning period being fixed and for last year's estimate for this same planning period into major contributors and distribute the results, as shown in Figure F1.2, to all Generator Unavailability Subcommittee members for their information. This information should be passed on to the P&E committee for its review.

The PJM member company representatives are responsible for determining and supplying the required information to the incumbent GUS chairman. The GUS chairman is responsible for compiling the tables and issuing the report.

An abbreviated sample of this report is included in Section VI, Figure F1.

## Section IV
## Periodic Reports

### Supplemental Agreement Outage Data Report

Outage data, based on the latest three full calendar years of operating data and excluding I.O. code 9 outages (i.e., routinely occurring off-peak outages), is used in the PJM capacity allocation formula to determine each member company’s capacity requirement. This data is provided to the PJM Planning & Engineering Committee for use in the Supplemental Agreement, Allocation of Forecast Requirement runs.

The report contains individual unit equivalent demand forced outage rates, weighted average equivalent demand forced outage rates, average unavailable capacity due to forced outages, and the average unavailable capacity due to planned and maintenance outages, all summarized by company for ten consecutive planning periods starting June 1 of the current year. The individual unit (hence, also the company average) equivalent demand forced outage rates are determined with planned outage extensions treated as planned outages.

The report is organized as follows:

| | |
|---|---|
| Transmittal Letter | |
| Cover Page: | Report Title, GUS Committee Representation |
| Body: | Foreword, Results |
| Table I: | PJM Company Average Equivalent Demand Forced Outage Rates |
| Table Ia: | PJM Company Average Forced Unavailable Megawatts |
| Table II: | PJM Company Average Planned and Maintenance Average Unavailable Megawatts |
| Table III: | Equivalent Outage Data for Classes of Future Units |
| Table IV: | Individual Equivalent Demand Forced Outage Rates for Existing and Future Capacity |
| Table V: | Capacity Allocation of PJM Units with Multiple Company Ownership |
| Appendix A: | Guidelines and Special Procedures for Outage Rate Calculations |
| Appendix B: | Summary of Units Placed on Deferred Maintenance for Economic Reasons |
| Appendix C: | Summary of Units Placed on Inactive Status |
| Appendix D: | Outage Rate Calculations for Large Units with Extended Outages |

The data source for this report is a GORP run made against the PJM outage data base which includes the outage history for the calendar year just ended. This GORP run must contain "Unit Summary Reports" of operating experience for each of the last five calendar years, cumulative for the last three years and the last five years, the "Probability of Unit Partial Outage State Report" and the "Unit Variance and Partial Outage State Report."

The incumbent GUS chairman is responsible for compiling and issuing this report. Responsibilities for each of the report’s components are identified in that component’s description.

An abbreviated sample of this report is included in Section VI, Figure F2.

Section IV
Periodic Reports

Supplemental Agreement Outage Data Report (continued)

Table I

PJM Company Average Equivalent Demand Forced Outage Rates
(Refer to Figure F2.4.2 for a sample Table I)

1. Individual Unit Equivalent Demand Forced Outage Rate Calculation:

Individual unit equivalent demand forced outage rates are computed first because they must be known to permit calculation of the company average rate for each planning period.

The annual unit $EFOR_D$ will be 100% for any period of operation after 1992 during which minimum reporting requirements are not met. Minimum reporting requirements are defined as either GADS event data or actual hourly net generation for units less than 10 MW. Table III values for $EFOR_D$ will be used for all years prior to the first full year of operation and for all non-reported years prior to 1992.

Companies that are unable to comply with the minimum reporting requirements after 1992 have the option to appeal to the Planning and Engineering Committee for an alternative to the 100% $EFOR_D$ ruling.

The individual unit rates are listed in Table IV of this report.

a. Mature Unit
The equivalent demand forced outage rate (%) of a mature unit is calculated using the latest three full calendar years of operating experience. The three year equivalent forced outage rate, with f-factor, is taken directly from the appropriate GORP output, unless a manual adjustment is necessary.

b. Immature Unit
The equivalent demand forced outage rate (%) of an immature unit is the weighted combination of its historical and class-average rates (i.e., Table III rates). For example, the rate for a unit with less than three full calendar years of operating experience is:

$$EFOR_D\ (\%) = \frac{n * EFOR_D\ (\%,\ \text{historical}) + (3-n) * EFOR_D\ (\%,\ \text{Table III})}{3}$$

where $EFOR_D$ (%, historical) must be manually calculated using Equation 2 given in Section III, page 5.

c. Future Unit
The equivalent demand forced outage rate (%) of a future unit is the class-average rate for its size and type indicated in Table III of this report.

d. Deferred Maintenance Unit
The equivalent demand forced outage rate (%) of a unit entirely on deferred maintenance, regardless of size, is the rate calculated using the last 36 full calendar months of operating experience excluding the deferment period. The deferment period starts when the estimated repair time has elapsed and ends on or before the expected return date. This means that a forced outage event ending when the estimated repair time has elapsed must be included in the unit’s history when calculating its forced outage rate.

Section IV

Periodic Reports
Supplemental Agreement Outage Data Report

Table I (continued)

PJM Company Average Equivalent Demand Forced Outage Rates
(Refer to Figure F2.4.2 for a sample Table I)

1. Individual Unit Equivalent Demand Forced Outage Rate Calculations: (continued)

d. Deferred Maintenance Unit (continued)

The equivalent demand forced outage rate (%) of a unit partially on deferred maintenance is calculated using the latest three full calendar years of operating experience, after adjusting the equivalent forced partial outage hours. The partial outage hour adjustment and forced outage rate are manually calculated using Section III, Equations 10 and 2.

Refer to Section V, Item D: Deferred Maintenance Forced Outage Adjustment Calculation Guidelines for additional information.

e. Mothballed Unit

A mothballed unit is removed from the outage rate calculations until it is reactivated and included in the company's installed capacity.

f. 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. Refer to Section VI, Figure 4.

2. Company Average Equivalent Demand Forced Outage Rate Calculation:

The weighted average of the individual unit forced outage rates is calculated using the formula:

$$EFOR_D = \frac{\sum_{i=1}^{n} (EFOR_{Di} * C_i)}{\sum_{i=1}^{n} C_i}$$

where: $n$ = number of units,
$EFOR_{Di}$ = $EFOR_D$ of unit i, % or per-unit,
$C_i$ = net summer installed capacity of unit i, MW.

Since this rate is calculated for each of 10 consecutive planning periods starting June 1 of the current year, it reflects the effect of capacity changes occurring during that period. The forced outage rate for a capacity change that occurs after the start of a planning period is scaled to reflect the fraction of the period for which that capacity was installed.

The rates to be shown for the current and next planning periods are those fixed by virtue of the PJM Management Committee's acceptance of the Supplemental Agreement, Allocation of Forecast Requirement for those periods as determined two and one planning periods, respectively, prior to the current planning period. Footnotes should be used to document these two rates. (NOTE: For the preliminary report, these two rates are to be shown in parenthesis, for comparison purposes, next to the values determined for the same planning periods using the latest information.)

Section IV
<u>Periodic Reports</u>

<u>Supplemental Agreement Outage Data Report</u>

Table I (continued)

<u>PJM Company Average Equivalent Demand Forced Outage Rates</u>
(Refer to Figure F2.4.2 for a sample Table I)

2. <u>Company Average Equivalent Demand Forced Outage Rate Calculation: (continued)</u>

Each PJM member company representative is responsible for calculating and transmitting these values to the incumbent GUS chairman. The GUS chairman is responsible for compiling this table for inclusion in this report.

Table Ia

<u>PJM Company Average Forced Outage Unavailable Megawatts</u>
(Refer to Figure F2.4.3 for a sample Table Ia)

1. <u>Individual Unit Unavailability Capability Calculations:</u>

Individual unit unavailable capability due to forced outages are determined first because they must be known prior to calculating the company average values for each planning period.

The annual unit EFOF will be 52 weeks/year for any period of operation after 1992 during which minimum reporting requirements are not met. Minimum reporting requirements are defined as either GADS event data or actual hourly net generation for units less than 10 MW. Table III values for EFOF will be used for all years prior to the first full year of operation and for all non-reported years prior to 1992.

Companies that are unable to comply with minimum reporting requirements after 1992 have the option to appeal to the Planning and Engineering Committee for an alternative to the 52 weeks/year EFOF ruling.

a. <u>Mature Unit</u>
The unavailable capability due to forced outages (MW-wks/yr) of a mature unit is calculated by multiplying the summer installed capacity by the EFOF. The EFOF is calculated by dividing the three year equivalent forced outage hours by three years times 168 hours per week. The three year equivalent forced outage hours is taken directly from the appropriate GORP output unless a manual adjustment is necessary.

b. <u>Immature Unit</u>
The forced outage weeks per year of an immature unit is the weighted-average combination of its historical and class-average (Table III) values of the Equivalent Forced Outage Factor (EFOF) multiplied by the summer installed capacity. For example, the value for a unit with 'n' full calendar years of operating experience is:

$$\text{MW-wks/yr} = \left[\frac{n * \text{EFOF(wk/yr, historical)} + (3-n) * \text{EFOF(wk/yr,Table III)}}{3}\right] \times \text{Summer Installed Capacity}$$

where EFOF (wk/yr) must be manually calculated using Equation 3 given in Section III, page 5.

Section IV
Periodic Reports

Supplemental Agreement Outage Data Report

Table Ia (continued)

PJM Company Average Forced Outage Unavailable Megawatts
(Refer to Figure F2.4.3 for a sample Table Ia)

1. Individual Unit Unavailability Capability Calculations: (continued)

c. Future Unit

The unavailability capability due to forced outages (MW-wks/yr) of a future unit is the class-average EFOF for its type indicated in Table III of this report multiplied by the summer installed capacity.

d. Deferred Maintenance Unit

The unavailable capability due to forced outages (MW-wks/yr) of a unit entirely on deferred maintenance, regardless of size, is calculated using the last 36 full calendar months of operating experience excluding the deferment period. The deferment period starts when the estimated repair time has elapsed and ends on or before the expected return date. This means that a forced outage event ending when the estimated repair time has elapsed must be included in the unit’s history when calculating its forced outage factor.

The unavailable capability due to forced outages (MW-wks/yr) of a unit partially on deferred maintenance is calculated using the latest three full calendar years of operating experience, after adjusting the equivalent forced partial outage hours. The equivalent forced outage factor is manually calculated using Section III, Equation 3.

Refer to Section V, Item D: Deferred Maintenance Forced Outage Adjustment Calculation Guidelines for additional information.

e. Mothballed Unit

A mothballed unit contributes nothing to the unavailable capacity calculations because it is not part of the company’s installed capacity.

f. 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. Refer to Section VI, Figure 4.

2. Company Average Unavailable Capacity Due to Forced Outages:

The total company unavailable capability due to forced outages (MW-wks/yr) in any planning period is the sum of the individual unit unavailable capabilities. The average company unavailable capacity (MW) is obtained by dividing the total company unavailable capability (MW-wks/yr) by 52 weeks. A company average unavailable capacity value is calculated for each of 10 consecutive planning periods starting June 1 of the current year. The unavailable capacity due to forced outages for a capacity change that occurs after the start of a planning period is scaled to reflect the fraction of the period for which that capacity was installed.

## Supplemental Agreement Outage Data Report

### Table Ia (continued)

### PJM Company Average Forced Outage Unavailable Megawatts

(Refer to Figure F2.4.3 for a sample Table Ia)

2. Company Average Unavailable Capacity Due to Forced Outages: (continued)

The Values shown for the current and next planning periods are those fixed by virtue of the PJM Management Committee’s acceptance of the Supplemental Agreement, Allocation of Forecast Requirement for those periods as determined two and one planning periods, respectively, prior to the current planning period. Footnotes should be used to document these two values. (NOTE: For the preliminary report, these two values are to be shown in parenthesis, for comparison purposes, next to those determined for the same planning periods using the latest data.)

Each PJM member company representative is responsible for calculating and transmitting these values to the incumbent chairman. The GUS chairman is responsible for compiling this table for inclusion in this report.

### Table II

### PJM Company Average Unavailable Capacity Due to Planned and Maintenance Outages

(Refer to Figure F2.4.4 for a sample Table II)

1. Individual Unit Unavailable Capability Calculations:

Individual unit unavailable capabilities are determined first because they must be known prior to calculating the company average values for each planning period. If, when calculating these values, an explicit planned maintenance outage forecast for a unit is not available, then the unit must be assigned the planned outage weeks per year appropriate for the unit’s size and type as given in Table III of this report. The individual unit unavailable capabilities are not included in any report.

a. Mature Unit

The unavailable capability (MW-weeks) of a mature unit is determined by adding the historical maintenance outage weeks per year, based on the latest three full calendar years of data, to the forecast planned outage weeks per planning period and multiplying the sum by the unit’s net summer installed capacity (MW). The planned outage information is obtained from the "Ten Year Unit Planned Maintenance Forecast" report issued by the PJM Maintenance Committee each February.

b. Immature Unit

The maintenance outage weeks per year of an immature unit is the weighted-average combination of its historical and class-average (i.e., Table III) values. For example, the value for a unit with ’n’ full calendar years of operating experience is:

$$\text{EMOF(wk/yr)} = \frac{n * \text{EMOF(wk/yr, historical)} + (3-n) * \text{EMOF(wk/yr, Table III)}}{3}$$

Section IV
Periodic Reports

Supplemental Agreement Outage Data Report

Table II

PJM Company Average Unavailable Capacity Due to Planned and Maintenance Outages
(Refer to Figure F2.4.4 for a sample Table II)

1. Individual Unit Unavailable Capability Calculations: (continued)

b. Immature Unit (continued)

Adding this value to the planned outage weeks per year and multiplying the sum by the unit's net summer installed capacity (MW) yields its unavailable capability (MW-weeks).

c. Future Unit

The unavailable capability (MW-weeks) of a future unit is determined by adding the appropriate Table III class-average maintenance outage weeks per year to the forecast planned maintenance weeks per planning period and multiplying the sum by the unit's net summer installed capacity (MW).

d. Deferred Maintenance Unit

The unavailable capability (MW-weeks) of a unit entirely on deferred maintenance is determined by adding the equivalent maintenance outage weeks per year, from the same time period of operating experience used to determine its forced outage rate, to the forecast planned maintenance weeks per planning period and multiplying by the unit's net summer installed capacity.

The unavailable capability (MW-weeks) of a unit partially on deferred maintenance is determined by adding the equivalent maintenance outage weeks per year, from the latest three full calendar years of operating experience, to the forecast planned maintenance weeks per planning period and multiplying the sum by the unit's net available capacity (i.e., the unit's net summer capacity less the capacity on deferred maintenance). Add the product of the capacity on deferred maintenance and the number of deferred maintenance weeks encompassed by the planning period to this value for each appropriate planning period.

Refer to Section V, Item D for additional information.

e. Mothballed Unit

A mothballed unit contributes nothing to the unavailable capability calculations because it is not part of the company's installed capacity.

f. 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. Refer to Section VI, Figure 4.

Section IV
Periodic Reports

Supplemental Agreement Outage Data Report

Table II (continued)

PJM Company Average Unavailable Capacity Due to Planned and Maintenance Outages
(Refer to Figure F2.4.4 for a sample Table II)

2. Company Average Unavailable Capacity Due to Planning and Maintenance Outages:

The total company unavailable capability (MW-weeks) in any planning period is the sum of the individual unit unavailable capabilities. The unavailable capability of any capacity change that occurs during a planning period should be adjusted by prorating the maintenance outage weeks prior to summing with the planned outage weeks and multiplying the sum by the net summer installed capacity (MW). The average company unavailable capacity (MW) is obtained by dividing the total company unavailable capability (MW-weeks) by 52 weeks. A company average unavailable capacity value is calculated for each of 10 consecutive planning periods starting June 1 of the current year.

The values shown for the current and next planning periods are those fixed by virtue of the PJM Management Committee’s acceptance of the Supplemental Agreement, Allocation of Forecast Requirement for those periods as determined two and one planning periods, respectively, prior to the current planning period. Footnotes should be used to document these two values. (NOTE: For the preliminary report, these two values are to be shown in parenthesis, for comparison purposes, next to those determined for the same planning periods using the latest data.)

Each PJM member company representative is responsible for calculating and transmitting these values to the incumbent GUS chairman. The GUS chairman is responsible for compiling this table for inclusion in this report.

Table III

Equivalent Outage Data for Classes of Future Units
(Refer to Figures F2.5.1 - F2.5.3 for a sample Table III)

The outage information contained in this table has been determined by statistical analyses performed on one or more of the PJM, NRC and NERC/GADS outage event databases. These analyses are performed periodically, at the discretion of the Generator Unavailability Subcommittee, to ensure that the values used for future units are reasonable, based on the historical performance of similar units.

Values from this table are used in the Table I, Table Ia and Table II calculations for this report whenever suitable historical, or forecast, information is unavailable.

The incumbent GUS chairman is responsible for including the most recent table in this report.

## Section IV
## Periodic Reports

### Supplemental Agreement Outage Data Report

### Table IV

### Individual Equivalent Demand Forced Outage Rates for Existing and Future Capacity
(Refer to Figures F2.6.1 - F2.6.8 for a sample Table IV)

This table contains a summary of the individual equivalent demand forced outage rates used in calculating the company average equivalent demand forced outage rates for the planning periods of interest. The table is comprised of two parts: one listing all existing capacity (i.e., capacity installed as of 24:00 on May 31 of the current calendar year) and one listing the schedule of capacity changes projected for 10 planning periods beginning June 1 of the current calendar year. The dates of future capacity changes should agree with those submitted by the P&E Committee which are used as input to the Supplemental Agreement runs to forecast each company’s capacity obligation.

Each PJM member company representative is responsible for providing the incumbent GUS chairman with a Table IV for inclusion in this report. All company owned capacity should be shown in this table. Units owned jointly with other utilities should be indicated as such on each owning company’s table.

### Table V

### Capacity Allocation of PJM Units with Multiple Company Ownership
(Refer to Figures F2.7.1 - F2.7.2 for a sample Table V)

This table identifies all PJM units that are owned by two or more utilities and specifies the capacity (MW) owned by each. Only joint-owned units in service prior to June 1 of the current planning period are to be shown in this table. Changes in ownership occurring after June 1 are already identified in Section I, Table III, "PJM Generating Capacity Additions" of the annual "Load and Capacity Forecast and Allocation of Forecast Requirements Report."

The incumbent GUS chairman is responsible for compiling this table for inclusion in this report.

### Appendix A

### Guidelines and Special Procedures for Calculating Supplemental Agreement Information
(Refer to Figures F2.9.1 - F2.9.4 for a sample Appendix A)

This appendix highlights the guidelines and special procedures used in calculating the information provided for the Supplemental Agreement’s Allocation of Forecast Reserve Requirement calculations. Specifically, it indicates exceptions to the normal treatment of the outage history used to calculate the outage data provided for this report.

The incumbent GUS chairman is responsible for including the most recent version of this appendix in this report.

# Section IV
# Periodic Reports

## Supplemental Agreement Outage Data Report

### Appendix B

### Summary of Units Placed on Deferred Maintenance for Economic Reasons

(Refer to Figure F2.10 for a Sample Appendix B)

This appendix identifies the specific units which have been placed on Deferred Maintenance for economic reasons. The information in this appendix is comprised of two parts: one listing those units currently on Deferred Maintenance and one listing all units that were previously placed on Deferred Maintenance but have either been returned to service or retired.

The Interconnection Office representative is responsible for providing the incumbent GUS chairman with the most recent information available. The GUS chairman is responsible for including this appendix in this report.

### Appendix C

### Summary of Units Placed on Inactive Status

(Refer to Figure F2.11 for a sample Appendix C)

This appendix identifies those units currently "mothballed" and placed on Inactive Status.

The Interconnection Office representative is responsible for providing the incumbent GUS chairman with the most recent information available. The GUS chairman is responsible for including this appendix in this report.

### Appendix D

### Outage Rate Calculations for Large Units with Extended Outages

(Refer to Figures F2.12.1 - F2.12.2 for a sample Appendix D)

This appendix identifies the units 600 MW or greater which have had outage durations that equalled or exceeded 12 consecutive months.

The incumbent GUS Chairman is responsible for including the most recent version of this appendix in this report.

# Section IV
## Periodic Reports

### Planning Study Outage Data Report

Planning study outage data is primarily intended for use by the Capacity and Transmission Planning Subcommittee to determine the PJM capacity reserve requirements. These data are also used to determine the Forced Outage Rate (F), Large Unit (U), and the Load Drop (D) adjustment factors used in the PJM Supplemental Agreement, Allocation of Forecast Requirement.

The report provides effective equivalent demand forced outage rates, capacity variances and scheduled outage data for all existing and future units included in the latest capacity schedule of each company. This information is based on the latest five full calendar years of operating experience and excludes I.O. code 9 outages (i.e., routinely occurring off-peak outages).

The report is organized as follows:

| | |
|---|---|
| Transmittal Letter | |
| Cover Page: | Report Title, GUS Committee Representation |
| Body: | Introduction, Results, Data Assumptions, Methodology |
| Table I: | Data for Units with Five Full Calendar Years of Operating Experience |
| Table IIa: | Data for Units with Less than Five Full Calendar Years of Operating Experience |
| Table IIb: | Data for Future Units |
| Table III: | Effective Equivalent Outage Data for Classes of Future Units |
| Table IV: | Forced and Scheduled Outage Data Components for Existing and Future Capacity |

The data source for this report are GORP runs made against the PJM GADS database which includes the outage history for the calendar year just ended. One run must contain "Unit Summary Reports" of operating experience for each of the last five years and cumulative for the last five years, the "Probability of Unit Partial Outage State Report" and the "Unit Variance and Partial Outage State Report." The second run must contain "Unit Summary Reports" of operating experience for last five years with scheduled extensions of maintenance and planned outages removed.

The incumbent GUS chairman is responsible for compiling and issuing this report. Responsibilities for each of the report’s components are identified in that component’s description.

An abbreviated sample of this report is included in Section VI, Figure F3.

### Table I

### Data for Units with Five Full Calendar Years of Operating Experience
(Refer to Figures F3.3.1 - F3.3.5 for a sample Table I)

Each PJM member company representative is responsible for providing to the incumbent GUS chairman a Table I for his own company’s capacity. However, information for joint-owned units should only appear in the table of the company operating those units.

Section IV
Periodic Reports

Planning Study Outage Data Report

Table I (continued)

Data for Units with Five Full Calendar Years of Operating Experience
(Refer to Figures F3.3.1 - F3.3.5 for a sample Table I)

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 ($EFOR_D$). The annual unit $EFOR_D$ will be 100% for any period of operation after 1992 during which minimum reporting requirements are not met. Minimum reporting requirements are defined as either GADS event data or actual hourly net generation for units less than 10 MW. Table III values for $EFOR_D$ will be used for all years prior to the first full year of operation and for all non-reported years prior to 1992.

Companies that are unable to comply with the minimum reporting requirements after 1992 have the option to appeal to the Planning and Engineering Committee for an alternative to the 100% $EFOR_D$ ruling.

The individual unit rates are listed in Table IV of this report.

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. Deferred Maintenance Unit

The effective equivalent demand forced outage rate (%) of a unit entirely on deferred maintenance is the rate calculated using the last 60 full calendar months of operating experience, excluding the deferment period. The deferment period starts when the estimated repair time has elapsed and ends on or before the expected return date.

The effective equivalent demand forced outage rate (%) of a unit partially on deferred maintenance is calculated using the latest five full calendar years of operating experience, after adjusting the equivalent forced partial outage hours. The partial outage hour adjustment and forced outage rate are manually calculated using equations 2, 8 and 10. Refer to Section V, Item D for additional information.

c. Mothballed Unit

A mothballed unit is ignored until it is reactivated and included in the company’s installed capacity.

d. 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. Refer to Section VI, Figure 4.

Section IV
Periodic Reports

Planning Study Outage Data Report

Table I (continued)

Data for Units with Five Full Calendar Years of Operating Experience
(Refer to Figures F3.3.1 - F3.3.5 for a sample Table I)

2. Capacity Variance Calculation:

a. Mature Unit
The capacity variance ($MW^2$) of a mature unit is calculated using the procedure given in Section V, 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. Deferred Maintenance Unit
The capacity variance ($MW^2$) of a unit on deferred maintenance is calculated using the procedure given in Section V, Item E: Capacity Variance Calculation Procedure for Existing Units. The information given in the appropriate GORP output will need to be manually adjusted until the deferment period is no longer part of the latest five full calendar years of operating experience.

c. Mothballed Unit
A mothballed unit is ignored until it is reactivated and included in the company's installed capacity.

d. 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.

$$V = MW^2 \times (1 - EEFOR_D) \times EEFOR_D$$

Refer to Section VI, Figure 4.

3. Scheduled Outage Data Calculation:

a. Mature Unit
The scheduled outage data of a mature unit is calculated based on the latest five full calendar years of operating experience and the "Ten Year Unit Planned Maintenance Forecast" used for the latest Supplemental Agreement Outage Data Report. 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.

Section IV
Periodic Reports

Planning Study Outage Data Report

Table I

Data for Units with Five Full Calendar Years of Operating Experience
(Refer to Figures F3.3.1 - F3.3.5 for a sample Table I)

3. Scheduled Outage Data Calculation: (continued)

b. Deferred Maintenance Unit

The scheduled outage data of a unit entirely on deferred maintenance is calculated based on the latest 60 full calendar months of operating experience, excluding the start of the deferment period, and the "Ten Year Unit Planned Maintenance Forecast" used for the latest Supplemental Agreement Outage Data Report. Ten years of scheduled outage weeks are determined for each unit by multiplying the forecast maintenance weeks by the EPOEF and adding to each 75% of the EMOF (weeks/year). The 60-month cumulative statistics are to be taken directly from the appropriate GORP output and used, unless manual adjustments are necessary.

The scheduled outage data of a unit partially on deferred maintenance is calculated based on the latest five full calendar years of operating experience and the "Ten Year Unit Planned Maintenance Forecast" used for the latest Supplemental Agreement Outage Data Report. Ten years of scheduled outage weeks are determined for each unit by multiplying the forecast maintenance weeks by the EPOEF 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.

Tables IIa & Table IIb

Data for Units with Less Than Five Full Calendar Years
of Operating Experience and Future Units
(Refer to Figures F3.4.1 - F3.4.3 for a sample Table II)

Each PJM member company representative is responsible for providing to the incumbent GUS chairman a Table IIa and Table IIb for his own company’s capacity. However, information for joint-owned units should only appear in the table of the company operating those 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 ($EFOR_D$).

Section IV
Periodic Reports

Planning Study Outage Data Report

Tables IIa & Table IIb

Data for Units with Less Than Five Full Calendar Years of Operating Experience and Future Units
(Refer to Figures F3.4.1 - F3.4.3 for a sample Table II)

1. Individual Unit Effective Equivalent Demand Forced Outage Rate Calculation: (continued)
The annual unit $EFOR_D$ will be 100% for any period of operation after 1992 during which minimum reporting requirements are not met. Minimum reporting requirements are defined as either GADS event data or actual hourly net generation for units less than 10 MW. Table III values for $EFOR_D$ will be used for all years prior to the first full year of operation and for all non-reported years prior to 1992.

Companies that are unable to comply with the minimum reporting requirements after 1992 have the option to appeal to the Planning and Engineering Committee for an alternative to the 100% $EFOR_D$ ruling.

The individual unit rates are listed in Table IV of this report.

a. 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., Table III rates). For example, the rate for a unit with ’n’ full calendar years of operating experience is:

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

where $EEFOR_D$ (%, historical) must be manually calculated using Equations 2, 4 and 8 given in Section III, pages 5 and 6.

b. 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 Table III of this report.

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 Table III class average rates until the combined cycle unit has mature operating history unless granted an exception. Refer to Section VI, Figure 4.

Section IV
Periodic Reports

Planning Study Outage Data Report

Tables IIa & Table IIb (continued)

Data for Units with Less Than Five Full Calendar Years
of Operating Experience and Future Units
(Refer to Figures F3.4.1 - F3.4.3 for a sample Table II)

2. Capacity Variance Calculation:

a. 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:

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

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 Table III of this report.

b. Future Unit

The capacity variance ($MW^2$) of a future unit is the value appropriate for the unit's size and type indicated in Table III of this report.

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.

$$V = MW^2 \text{ X } (1 - EEFOR_D) \text{ X } EEFOR_D$$

Refer to Section VI, Figure 4.

3. Scheduled Outage Data

a. Immature Unit

The scheduled outage data for an immature unit (Table IIa), is comprised of the following components:

1) Ten Year Planned Maintenance Forecast;
2) The equivalent planned outage extension factor (EPOEF);
3) The equivalent maintenance outage factor (EMOF) in weeks per year;
4) Years of service; and
5) The ten year scheduled outage weeks (Table III).

Section IV
Periodic Reports

Planning Study Outage Data Report

Tables IIa & Table IIb

Data for Units with Less Than Five Full Calendar Years of Operating Experience and Future Units
(Refer to Figures F3.4.1 - F3.4.3 for a sample Table II)

3. Scheduled Outage Data (continued)

a. Immature Unit (continued)
The yearly calculation for scheduled outage data for a unit with 'n' full calendar years of operating experience is:

Scheduled Outage (Yearly) =

[ [((Planned Maint.(wks/yr) X EPOEF) + (0.75 X EMOF (wks/yr))) X n]

+

[Table 3 Scheduled Outage Weeks (wks/yr) + (0.75 X EMOF (Table 3))] X (5 - n) ] / 5

where EPOEF and EMOF (historical) must be manually calculated using Equations 6 and 4 respectively as given in Section III, pages 5 and 6.

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 Table III of this report.

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 Table III class average values until the combined cycle unit has mature operating history unless granted an exception. Refer to Section VI, Figure 4.

Table III
Effective Equivalent Outage Data for Classes of Future Units
(Refer to Figure F3.6 for a Sample Table III)

The outage information contained in this table has been determined by statistical analyses performed on one or more of the PJM/GADS, NRC and NERC/GADS outage event databases. These analyses are performed periodically, at the discretion of the Generator Unavailability Subcommittee, to ensure that the values used for future units are reasonable, based on the historical performance of similar units. Values from this table are used in the Table I, Table IIa and Table IIb calculations for this report whenever suitable historical, or forecast, information is unavailable.

The incumbent GUS chairman is responsible for including the most recent version of this table in this report.

# Section IV
## Periodic Reports

### Adequacy and Reliability Assessment Report

The Adequacy and Reliability Assessment Report is prepared annually under the Planning & Engineering Committee's direction to provide assessment of the PJM system performance. This report is prepared jointly with the following groups: Planning & Engineering Committee, Capacity & Transmission Planning Subcommittee, Load Analysis Subcommittee, System Reliability Task Force, Generation Unavailability Subcommittee, and Load and Capacity Working Group.

The GUS section of the Adequacy and Reliability Assessment Report contains the following two tables:

1) PJM Unavailable Capacity at Peak Hour for Selected Heavy Load Days

2) PJM Internal Capacity and Reserves at Peak Hour for Selected Heavy Load Days

The incumbent GUS chairman has the responsibility of the delegation of the compilation and issuing of these tables. Responsibilities for each of the tables are identified as follows:

### PJM Unavailable Capacity at Peak Hour for Selected Heavy Load Days
(Refer to Figures F5.1 for a sample table)

Each PJM member company representative is responsible for providing to the designated GUS member a table entitled "Unavailable Capacity at Peak Hour for Selected Heavy Load Days" for his own company's capacity.

This table contains a section for both Planned and Unplanned Outages. The Unplanned outages include both forced and maintenance outages. Each section includes the unavailable capacity for each of the following categories: Hydro, Nuclear, Coal, Oil/Gas, CT & Diesel, and NUG. Unavailable capacity totals are calculated for each selected day with subtotals for both the Planned and Unplanned outages.

The PJM member companies' tables are compiled to create a single table to represent the PJM capacity. Refer to Section VI, Figure 5.1.

### PJM Internal Capacity and Reserves at Peak Hour for Selected Heavy Load Days
(Refer to Figure 5.2 for a sample table)

The designated GUS member compiles a table called "PJM Internal Capacity and Reserves at Peak Hour for Selected Heavy Load Days. The GUS selects the specified days and times by which this and the previous table is constructed. The specified days and times are submitted to the Planning and Engineering Committee for approval.

This table contains the following items:

1) PJM Actual Peak (MW)
2) PJM Forecasted Weekly Peak (MW)
3) PJM Available Internal Capacity (MW)
4) Reserve as % of Actual Peak
5) Reserve as % of Forecasted Peak
6) PJM Internal Capacity (MW)
7) PJM Planned Outages (MW)
8) PJM Unplanned Outages (MW)
9) PJM Total Outages (MW)
10) Unplanned Outages as % of Internal Capacity

I. PJM Available Internal Capacity is calculated as follows:

PJM Internal Capacity - PJM Total Outages

(PJM Internal Capacity = PJM Installed Capacity - Firm Installed Capacity Purchases)

II. The Reserve as % of Actual Peak is calculated as follows:

[(PJM Available Internal Capacity - PJM Actual Peak) / PJM Actual Peak] x 100

III. The Reserve as % of Forecasted Peak is calculated as follows:

[(PJM Available Internal Capacity - PJM Forecasted Weekly Peak) / PJM Forecasted Weekly Peak] x 100

The PJM Planned, Unplanned and Total Outages are taken from the "PJM Unavailable Capacity at Peak Hour for Selected Heavy Load Days" Table.

Unplanned Outages as a % of Internal Capacity is calculated as follows:

[PJM Unplanned Outages / PJM Internal Capacity] x 100

## Section V
## Miscellaneous Documentation

### 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.

```
+---------------+            (1 - P_s) / T         +---------------+
|   Reserve     | ---------------------------------->>|               |
|   Shutdown    |                                   |    On Line    |
|               |                1 / D              |               |
|   State "0"   |<<-------------------------------- |   State "2"   |
+---------------\                                   +---------------+
  A              \                                    A          |
  |               \            P_s / T                |          |
  | 1 / r          +->>-----------------+       1 / r |   1 / m  |
  |                                      \            |          |
  |                                       \           |          V
+---------------+                1 / T          +->>+---------------+
|  Forced Out   | ---------------------------------->>|  Forced Out   |
|       &       |                                   |       &       |
|  Not Needed   |                1 / D              |    Needed     |
|   State "1"   |<<-------------------------------- |   State "3"   |
+---------------+                                   +---------------+
```

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

$$P = P_3 / (P_2 + P_3).$$

---

(*) "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, pages 618-627.

Section V
Miscellaneous Documentation

Item A

Full f-Factor Derivation (continued)

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

$$P_2 = SH / (AH + FOH) \quad \text{and} \quad P_1 + P_3 = FOH / (AH + FOH).$$

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

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

This can also be expressed as

$$\begin{aligned} F_1 &= P_3 * \text{rate of entry from state 3} \\ &= P_3 * (1/D). \end{aligned}$$

Equating these two expressions and solving for $P_1$ yields

$$P_1 = P_3 * \frac{1/D}{1/r + 1/T}.$$

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

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

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.

Section V

Miscellaneous Documentation

Item A

Partial f-Factor Derivation

```
                +--- Forced Partial Outage Hours
        +------|--------+---------+-----+---------------+---------------+
        |///// | ////////////////|     |         |     |               |
        |///// V ///////////+-----'    | f_f* FOH       |               |
        |/////////////+-----'          |<------->|     |               |
        |///////+-----' |              |               |               |
        |-------'       |              |         |     |               |
Capacity|               |              |               |               |
  (MW)  |      RSH      |      SH      |      FOH      |   MOH + POH   |
        |               |              |     (full)    |    (full)     |
        |               |<----- Demand Time ----->|    |               |
        |               |              |               |               |
        |<------ Available Hours ------>|        |     |               |
        |               |              |               |               |
        +---------------+--------------+---------------+---------------+

        <-----------------------  Period Hours  ------------------------>
```

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

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

Section V

Miscellaneous Documentation

Item B

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

$$T = (1 - EEFOR_D) * C$$

where $T$ = 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

$$[^2 = (1 - EEFOR_D) * EEFOR_D * C^2$$

where $[^2$ = 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:

$$C' = \frac{T}{1 - EEFOR_D'} \quad \text{and} \quad EEFOR_D' = \frac{[^2}{T^2 + [^2}$$

where $C'$ = modified two-state unit net capacity, MW, and
$EEFOR_D'$ = modified two-state $EEFOR_D$, per-unit.

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## Miscellaneous Documentation

### Item C

### Rules for Consistency of Generator Outage Rate Calculations(*)

1. Any errors or inconsistencies found in the PJM Outage Data History File must be corrected.

2. All revisions to outage rates, for reasons of data integrity, must be accomplished by revising the PJM Outage Data History File. If this is not possible, manual revisions to the rates calculated by the Generator Outage Rate Program must meet the following conditions:

   a) The manual adjustment must be documented and presented to the Generator Unavailability Subcommittee no later than one month prior to the rate publication deadline.

   b) The manual adjustment must be approved by a majority of the Generator Unavailability Subcommittee members.

   c) The manual adjustment must be documented in the rate publication.

   d) The discrepancies found in the PJM Outage Data History File which necessitated the manual adjustment must be corrected through established data correction channels to avoid future manual adjustment.

3. Any outages due to natural disasters (e.g., 1972 Agnes Flood), which the Generator Unavailability Subcommittee 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.

4. A unit’s forced outage rate may be discounted to reflect an official capacity derating provided the following conditions are met:

   a) The derating caused the termination of a forced partial reduction which reflected the unit’s reduced capability during the period from January 1, 1972 through May 31, 1974 (1).

   b) Formal documentation of the derating adjustment must be presented to the Generator Unavailability Subcommittee no later than one month prior to the rate publication deadline.

   c) The derating adjustment must be approved by a majority of the Generator Unavailability Subcommittee members.

   d) The derating adjustment must be documented in the rate publication.

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Miscellaneous Documentation

Item C

Rules for Consistency of Generator Outage Rate Calculations(*) (continued)

4. (continued)

The rate discounting is accomplished by deleting the reported forced partial outage time from the Outage Data History File and subtracting the forced partial reduction capacity from any net maximum dependable capacity that was reported concurrently with the reduction (2).

5. The annual unit $EFOR_D$ will be 100% for any period of operation after 1992 during which minimum reporting requirements are not met. Minimum reporting requirements are defined as either GADS event data or actual hourly net generation for units less than 10 MW. Table III values for $EFOR_D$ will be used for all years prior to the first full year of operation and for all non-reported years prior to 1992.

Companies that are unable to comply with the minimum reporting requirements after 1992 have the option to appeal to the Planning and Engineering Committee for an alternative to the 100% $EFOR_D$ ruling.

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(*) 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."

(1) It would not be feasible to adjust for deratings prior to this period due to less stringent data reporting requirements that were in effect. Adjustments for deratings occurring subsequent to this period are not legitimate. The PJM contract contains provisions to rerate units within a reasonable time. During periods where a unit is overrated and a forced partial reduction is reported, the higher capacity tends to compensate for the increased forced outage rate and future forecast capacity obligation. Thus, an adjustment for the partial reduction in the outage history would provide a redundant credit.

(2) An example of a unit satisfying condition 4a. is England 1. The reported maximum net dependable capacity of this unit for the period 1/1/72 through 5/31/74 was 132MW. For the entire 29 month period, the unit had a 5MW forced capacity reduction. The unit was derated 5MW effective 6/1/74. In compliance with these rules, the 5MW forced reduction was deleted from the PJM Outage History File and the net maximum dependable capacity was changed to 127MW (132MW minus 5MW) for use in determining the equivalent outage hours.

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Item D

Deferred Maintenance Forced Outage Adjustment Calculation Guidelines

Units with Deferred Maintenance are afforded special treatment so as not to penalize the company for its inability to repair a unit because of financial constraints. Capacity can also be put in this category if the company has more than it needs to meet its requirements and does not need to repair the unit.

The event for which the Deferred Maintenance classification was requested had to be a forced outage, since extensions of planned and maintenance outages for the same cause as the original outage are treated as planned and maintenance outages, respectively. Furthermore, forced outages are penalized in the determination of each PJM member company's installed capacity obligation. Hence, only forced outage events would require adjustment. The time the unit is on deferred maintenance has two components: Estimated Repair Time and Deferment Period. The unit's history will include a forced outage event which is assumed to start immediately and has a duration which includes the Estimated Repair Time. When the estimated repair time has elapsed, the Deferment Period begins and continues until the date and time requested when application was made for Deferred Maintenance.

For units entirely on deferred maintenance, the outage statistics for the 'm' full calendar months prior to the start of the Deferment Period are to be used for all outage data calculations, unless manual adjustments are necessary to correct event data errors. Once the unit has been returned to active status, the 'm-x' full calendar months before and 'x' full calendar months after the Deferment Period comprise the 'm' full calendar months of operating experience data needed to calculate the equivalent forced outage rate (i.e., 36 for reserve allocation and 60 for reliability usage). It will be necessary to use this split time interval until three full calendar years of operating experience are again continuous.

For units partially on deferred maintenance, the outage statistics for the latest 'n' full calendar years (including the deferment period) are to be used. Manual calculations are necessary to remove the effects of the forced outage event during the deferment period. The equation used to adjust the equivalent forced partial outage hours is:

$$EFPOH' = EFPOH - (1 - EFOR_{Dn}) * (PH_{DF} - OH_{DF}) * (MW_{RED} / MW_{RAT})$$

where:

$EFPOH'$ = adjusted equivalent forced partial outage hours,

$EFPOH$ = equivalent forced partial outage hours for the current 'n' year period,

$EFOR_{Dn}$ = equivalent demand forced outage rate for the last 'n' full calendar years of history prior to the start of Deferred Maintenance (per-unit),

$PH_{DF}$ = deferment period hours encompassed by the current 'n' year period,

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Miscellaneous Documentation

Item D

Deferred Maintenance Forced Outage Adjustment Calculation Guidelines (continued)

$OH_{DF}$ = full forced, maintenance and planned outage hours that occur within the deferment period hours of the current 'n' year period,

$MW_{RED}$ = amount of capacity on deferred maintenance (MW),

$MW_{RAT}$ = unit net summer installed capacity rating (MW), and

n = appropriate number of calendar years:

3 for reserve allocation usage, or

5 for reliability (GEBGE) usage.

The following time line and time window explanations indicate the appropriate PH and OH values to use in the EFOH adjustment equation.

```
       |                                                                    |
       |<-----  Total Time Unit has Capacity on Deferred Maintenance  ----->|
       |                          |                                         |
       |<---  Estimated Time  --->|<----------  Deferment Period  --------->|
       |        of Repair         |                                         |
       |   (Forced Outage Time)   |            |<-- Full Outage -->|        |
       |                          |            O1         O2       O3       |
       T0                         T1                      T2                T3

   <---  Window 1  ------->|
   <------------------------  Window 2  ---------------->|
                           |<-------------------------------  Window 3  ---------->
                           |                             |
                       calendar                      calendar
                       year end                      year end
```

Window 1:

Since the deferment period has not yet begun, the outage data for the latest 'n' full calendar years must be taken directly from the appropriate GORP run. The forced outage hours will include the event for which Deferred Maintenance has been requested and no adjustments are to be made to the equivalent forced partial outage hours, EFPOH. The estimated time of repair has not yet elapsed.

Window 2:

Since the window includes part of the deferment period, a manual adjustment is now necessary. For the adjustment, the period hours in the deferment period, PH(DF), are shown in the diagram as the time from T1 to T2. The total full outage hours due to forced, maintenance and planned outages, OH(DF), are shown in the diagram as the time from O1 to O2.

## Item D

### Deferred Maintenance Forced Outage Adjustment Calculation Guidelines
(continued)

Window 3:

Since the window still includes part of the deferment period, a manual adjustment is necessary. For the adjustment, the period hours in the deferment period, PH(DF), are shown in the diagram as the time from T1 to T3. The total full outage hours due to forced, maintenance and planned outages, OH(DF), are shown in the diagram as the time from O1 to O3. The equivalent forced outage rate used in the equation is that previously determined for Window 1. The equivalent forced partial outage hours to be used in the equation are those occurring in Window 3 which are determined from the appropriate GORP output by subtracting the unit's full forced outage hours from its equivalent full forced outage hours (EFPOH = EFOH - FOH). A Window 3-type adjustment must be made until the deferment period is no longer included in the 'n' full calendar years of the window.

The equivalent forced outage rate (EFOR) can now be calculated using Section III, Equation 2 given on page 5.

## Item E

### Capacity Variance Calculation Procedure for Existing Units

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

$$T = \sum_{i=1}^{n} (C_i * P_i) \quad , \qquad C_i = (1-D_i) * C$$

and

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

where
- $T$ = 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
- $\sigma^2$ = variance, $MW^2$.

## Section V

# Miscellaneous Documentation

### Item E

### Capacity Variance Calculation Procedure for Existing Units (continued)

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

$$T = (1 - EEFOR_D) * C \quad .$$

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

partial forced out state (i% out) ---> $H_i = f_p * FPOH_i + f_m * MPOH_i$

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

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

$$P_o = \frac{H_o}{DH} \qquad P_{100} = \frac{H_{100}}{DH} \quad \text{and} \quad P_i = \frac{H_i}{DH}$$

The individual state variances can now be calculated using the equation

$$\sigma_i^2 = \sum_{i=0}^{100} ((1 - D_i) * C - T)^2 * P_i \;,$$

where $D_i$ = per-unit average unavailability of state i,
$C$ = unit net summer installed capacity, MW,
$T$ = mean capacity, MW, calculated using the unit's EEFOR
$P_i$ = per-unit probability of being in state i.

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Miscellaneous Documentation

Item E

Capacity Variance Calculation Procedure for Existing Units
(continued)

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

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## Miscellaneous Documentation

### Item F

### Generator Unavailability Subcommittee Programs

### Introduction

To prepare the three reports described in Section IV, it is necessary for the Generator Unavailability Subcommittee members to analyze the raw outage events and process it to yield outage data for all of the existing units. For PJM Supplemental Agreement work, the individual unit force outage rates are used to determine the company average forced outage rate. Although this work can be done manually, several computer programs have been written to facilitate processing the outage data events and calculating the necessary outage rates. The programs currently available are:

- Generator Outage Rate Program (GORP)
- Supplemental Agreement Average Company EFOR Program

A summary describing each program is presented on the following pages.

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Miscellaneous Documentation

Item F

Generator Unavailability Subcommittee Programs (continued)

1. Generator Outage Rate Program (GORP)

The Generator Outage Rate Program was developed for use by PJM with the primary purpose of developing outage rates for use in reliability studies and in capacity reserve allocations. Specifications for this program were developed by the PJM Generator Unavailability Subcommittee and program development was performed by the PJM Program Development Subcommittee (*).

GORP is actually two programs, an edit and a main program, which can be executed separately. The GORP EDIT program processes the PJM GADS Outage Rate History File and the PJM Monthly Data File to produce an edited and reorganized file for use by the MAIN program. Errors detected during the edit are listed in an output report and the data in question is either modified or deleted from the output file produced by this program. The file reorganization is designed to improve the execution speed of the MAIN program.

The EDIT program can produce a back-up file consisting of all the data sets required by the MAIN program. It can also read the back-up file and recreate these data sets in the form required by the MAIN program. This feature enables transferring the data files for use at a different computer installation within the Interconnection.

Finally, the EDIT program can output the Attribute and Cause Code Description Files used by the MAIN program. The Cause Code File can be modified using control cards. The Attribute File can be modified by altering the card image input to the EDIT program routine which creates the Attribute File.

The MAIN program processes user input control cards which define the scope and desired output for a given study. The files produced by the EDIT program are then processed to accumulate outage data into the various groupings defined by the user. After accumulating the outage data, the Main program calculates the various rates and other statistics in accordance with the user defined specifications for this run. The desired reports are then produced.

The MAIN program can produce five reports. A brief description of the information provided in each follows:

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(*) Refer to the document titled "Specifications for the PJM Outage Rate Program for Installed Capacity Studies," prepared by the Generator Unavailability Subcommittee and transmitted to the PJM Planning and Engineering Committee via J.A. Hynds letter to R.J. Donaldson, Jr., P&E Committee chairman, dated April 9, 1973.

Section V
Miscellaneous Documentation

Item F

Generator Unavailability Subcommittee Programs (continued)

1. Generator Outage Rate Program (GORP) (continued)

Unit Summary Report

This report provides outage rates and related data for individual units or groups of units. Information in this report is the basis for determining outage rates used in reliability studies and capacity allocation runs.

Cause Code Component Outage Rate Report

This report categorizes the information in the Unit Summary Report according to equipment components. It is useful in determining problem areas for specific units.

Probability of Unit Partial Outage State Report

This report categorizes partial outage events into ten partial outage states representing reductions in unit capacity. Each state represents 10% of the unit's full load capability. This information, along with data for the 100% available and 100% forced out states, is used to calculate the capacity variance of each unit for use in reliability studies.

I.O. Code Component Outage Rate Report

This report summarizes the forced and maintenance outage event information into classifications defined by the postponability of the outages. This information should be useful to other groups, such as the PJM Maintenance and Operating Committees, who need to define outages differently than the PJM Planning and Engineering Committee.

Unit Variance and Partial Outage State Report

This report displays the effective forced outage rate, scheduled outage factor and capacity variance values required for the "Planning Study Outage Data Report." Also, the outage state summary shows all of the capacity state values used to calculate the capacity variance. Of the 101 potential outage states, only those with values are displayed.

Consult the program's User Guide to obtain detailed input and output information.

A sample, typical output from GORP is provided on pages 41-43 of this document.

2. Supplemental Agreement Average Company EFOR Program

This program was developed for use by PJM with the primary purpose of calculating company average forced outage rates for use in developing company forecast installed capacity obligations in accordance with the PJM Supplemental Agreement.

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Miscellaneous Documentation

Item F

Generator Unavailability Subcommittee Programs (continued)

2. Supplemental Agreement Average Company EFOR Program (continued)

It is a simple, straightforward program which calculates weighted average forced outage rates on a planning period basis for as many period as required by the input data. The program requires four pieces of information for each capacity change entered:

- capacity designation (up to 15 characters),
- service date, e.g., '12 94' (blank for existing capacity),
- installed capacity value, MW (negative for retirement),
- forced outage rate, per-unit.

Capacity changes that occur within a given planning period are assigned weighting factors which prorate the capacity to reflect the portion of the period for which it will be inservice. The program interprets a capacity change with a service date of '5 94' as taking place at 24:00 on May 31, 1994, meaning it will be in effect for the entire planning period, and is assigned a weighting factor of 1.0. A capacity change with an entered service date of '10 94' is interpreted as taking place at 24:00 on October 31, 1994, meaning it will be in effect from November through May or seven months of the planning period, and is assigned a 7/12ths, or 0.58333..., weighting factor.

The weighted capacity values for each change is multiplied by its forced outage rate to yield its contribution to the forced outage capacity. For each planning period, these forced capacity values are summed and divided by the summation of the weighted installed capacity values to yield a weighted average forced outage rate. The value calculated for existing installed capacity applies to all subsequent planning periods until a capacity change occurs. Similarly, the value calculated for any given planning period applies to all subsequent planning periods until another capacity change occurs.

NOTE: Since the program cannot distinguish an equivalent demand forced outage rate from a forced outage rate calculated according to any other method, it will accept any input value between 0 and 1. However, the PJM Supplemental Agreement inherently requires that company forced outage rates be determined using equivalent demand forced outage rates because it requires the use of unit forced outage rates as determined by the Planning and Engineering Committee, which has approved the use of equivalent demand forced outage rates." (*)

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(*) Refer to the PJM Supplemental Agreement: Schedule 2.11 (b)(5), "Guidelines for Calculation of Forecast Requirements of the Interconnection," issued April 1, 1974, effective June 1, 1974; and Schedule 2.212, Revision No. 1, (d-g), "Forced Outage Rate Adjustments (F)," issued June 15, 1977, effective August 1, 1977.