

**BULK ELECTRICITY SYSTEM OPERATIONAL  
PERFORMANCE : MEASUREMENT SYSTEMS  
AND SURVEY RESULTS**

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**Prepared by Working Group 39.05 at the request of Mr J. Svoen,  
(Past Chairman) and Mr A. Merlin (Current Chairman) of Study Committee 39  
(Power System Operation and Control)**

**July 1989**



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BULK ELECTRICITY SYSTEM OPERATIONAL PERFORMANCE:  
MEASUREMENT SYSTEMS AND SURVEY RESULTS

by

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July 1989

Prepared by CIGRE Working Group 39.05 at the  
request of Mr. M.J. Svoen, (Past Chairman) and  
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FOREWORD

Work in CIGRE on Bulk Electricity System overall performance measurements began in the late 1970s, leading to the presentation of the paper "Measuring and Reporting Overall Reliability of Bulk Electricity Systems" at the CIGRE 1980 Session. The motivation for this work came from two beliefs - that the electricity supply industry should have quantified performance information about the product that it was delivering to its customers, and what cannot be measured cannot be well managed.

In 1983, CIGRE Study Committee 39, Power System Operation and Control, established Working Group 05 to carry on this work on operational performance measures. During the period up to 1988, the previous work was reviewed and improved, and new work areas were added, so that consideration was given to performance measures for all the principal operational objective areas.

This Brochure summarizes the work to date. It is considered that the performance measures adopted are sufficiently advanced and sufficiently useful so as to encourage utilities that do not now measure performance to do so - and to do so in a way that enlarges a standardized set of data, thus making the process more valuable to all concerned.

1.0 INTRODUCTION

The Bulk Electricity System (BES) consists of integrated generation and transmission systems. It supplies electricity to the Distribution Electricity System (DES). CIGRE Study Committee 39 has identified three objectives for BES operations management[1]:

Security - the capability to withstand failures which could lead to a blackout.

Quality - the supply to customers at any time of sufficient energy at defined quality levels of voltage and frequency.

Cost - the minimization of total costs influenced by the BES operations function.

Effective operations management for these objectives requires a process analogous to a feedback control loop. Measures and standards of performance must be established for each objective. Actual performance must be measured and compared to the standards. When observed performance differs from standard, controlling action may be desirable. This will require decisions in which alternatives such as modifications to operational practices or operating criteria are evaluated in terms of their expected resulting performance changes.

Thus, measurement systems are required to monitor overall operational performance. The first CIGRE work in this field was the development of a rudimentary measurement system for BES security and supply quality.[2] This work was in the name of the then Study Committee 32 (System Operations and Control).

Study Committee 39 established Working Group SC39.05 (now Operational Performance of Power Systems) in 1983. During the past five years WG05 has undertaken a number of activities which built upon this previously-laid foundation. As reported in this brochure, the previous work on Security and on the continuity aspect of Quality was reviewed and improved; work on frequency and voltage was added to the previous work on Quality, and work on Cost was included for the first time. The Working Group also developed a performance measurement system for Control Aids[3] and conducted a survey of results, as reported in Electra[4].

## 1.1 Measurement Philosophy

Consideration had to be given to whether the measurement systems should emphasize the collection of information in sufficient quantity and detail to permit analysis of reasons for performance differences, or whether emphasis should be placed on simpler systems that would point up differences in performance (but not the reasons therefore), and which would not create an undue burden in data collection sufficient to discourage use of the systems and participation in surveys.

Consideration also had to be given to maximizing the use of data already collected by the industry.

It was decided to focus on simplicity on the basis that the more urgent need was for a performance data base of sufficient size so as to legitimize performance comparisons, and so that surveys could be repeated over time with minimum additional effort, thus making it possible to detect performance trends.

Data on characteristics was kept to a minimum, only fundamental system characteristics and supply methodologies being included. This did permit some assessment of performance differences.

More complex analysis of differences, and the development and use of performance models will likely require an additional data base.

## 1.2 Organization of Material

Most of the balance of this Brochure is divided into three main sections which correspond to the three objectives of BES operations management - Security, Quality and Cost. These main sections describe the performance measurement systems adopted, performance indices and displays derived from these measurement systems, and the performance measurements and results obtained through surveys. There is also a brief concluding section.

## 2.0 SECURITY

Security is the capability of a system to withstand failures that could lead to blackouts, i.e., BES System Disturbances.

A BES Disturbance is defined as an event resulting in widespread interruption of customers and characterized by one or more of the following phenomena:

- loss of system stability,
- cascading outages of transmission lines, and
- abnormal range of frequency or voltage or both.

### 2.1 Measurement System

Two indices were adopted to measure the customer impact of a BES Disturbance; these were Severity and Degree of Severity.

Severity is measured in System Minutes and is defined as the unsupplied energy in an event, in MW-Minutes, divided by the annual peak system load in MW. One System Minute is equivalent to an interruption of the total system load for 1 minute at time of the annual system peak.

Normalization through division by the annual peak load facilitates year-to-year and utility-to-utility comparisons.

For ease of presentation and assessment, severity measurements were grouped by Degree of Severity in accordance with the following definitions:

Degree 0 - An unreliability condition normally considered acceptable.

Degree 1 - An unreliability condition which may have significant impact to one or more customers, but is not considered serious. Typically less than a factor of 10 above that which is normally considered acceptable.

Degree 2 - An unreliability condition which is of serious impact to customers. Typically the customer impact is 10 to 100 times above that which is normally considered acceptable.

Degree 3 - Very serious impact to customers. Typically 100 to 1 000 times above that which is normally considered acceptable.

The following scale for measuring the Degree of Severity of individual BES Disturbances was adopted:

<u>Degree of Severity</u>	<u>Severity</u>
Degree 0	Less than 1 System Minute
Degree 1	1 to 9 System Minutes
Degree 2	10 to 99 System Minutes
Degree 3	100 to 999 System Minutes

The following data are to be recorded for each BES Disturbance:

- Date and Time
- Duration
- Unsupplied Energy
- Cause
- Severity
- Degree of Severity

In addition to recording BES Disturbance data, this measurement system may be applied to measure other unreliability events, such as interruptible load cuts, rotational load cuts by underfrequency and undervoltage protection systems or by automatic system load rejection, etc.

BES Disturbance performance is reported by calculating the degree of severity of each disturbance and the frequency of disturbances in events per annum for each degree of severity, i.e.:

$$\text{Frequency} = \frac{\text{No. of BES Disturbances}}{\text{No. of Years}}$$

### 2.2 Survey

An international survey of utility disturbance performance was initiated by Working Group 05 in March 1983. A set of basic utility characteristics was defined to assist in explaining differences in performance, and also to allow utilities to compare their performance with systems with the same basic characteristics.

These characteristics were the utility's size, its relative location in the interconnected network, and the nature of its internal transmission limitation, as follows:

System Size Factor (SSF)

SSF A -  $\geq 10\ 000$  MW annual peak load

SSF B - 1 000 - 9 999 MW annual peak load

SSF C -  $\leq 999$  MW annual peak load

Relationship of the Utility In the Interconnected System

U1 - A utility which is part of a very much larger interconnection and occupies a central position in that interconnection.

U2 - A utility which is part of a very much larger interconnection but is on the periphery of that interconnection.

U3 - A utility which is not interconnected with neighbours or is by far the largest partner in any interconnection.

Nature of System Limitations

a - A utility having a multiple meshed transmission system with thermal rather than stability or voltage limits on transmission capability, and dispersed generation and demand.

b - A utility having a lightly meshed transmission system with stability or voltage rather than thermal limits, and localized centres of generation and demand.

Using these basic characteristics, AU1a describes a utility with an annual peak load not less than 10 000 MW, which is centrally located in a large interconnected system, and which has a thermally limited transmission system.

The recipients of the survey were requested to indicate their utility characteristics, and the number of Degree 1, 2, and 3 Disturbances during the 10-year period from 1973 to 1982. Degree 0 Disturbances, being of relatively insignificant impact, were omitted from the survey.

SYSTEM SIZE FACTOR (SSF)	U1	U2	U3	TOTAL
A	a 8 b 3	a 2 b 3	a 3 b 1	20
B	a 42 b 13	a 18 b 24	a 6 b 7	110
C	a 15 b 4	a 10 b 8	a 0 b 1	38
TOTAL	85	65	18	168

TABLE 1 - CHARACTERISTICS OF REPORTING UTILITIES

A total of 168 utilities participated in the survey, giving 1 333 utility years of experience. The responses included a significant number of utilities from both Europe (41) and North America (102). The distribution of responding utilities by their characteristics of system size, interconnection relation, and nature of system limitation is shown in Table 1.

2.3 Survey Results

As reported in a paper[5] at the 1986 Session, specific Disturbance Frequency results are given in Table 2. The data used in calculating Disturbance Frequency are enclosed in brackets in the form of (X/Y) where X is the number of disturbances of specified Degree of Severity and Y is the utility years of experience. From the data available in this table, a utility can compare its performance with the average performance of others with similar characteristics.

Degree 1:

	U1	U2	U3
A	a (4/80) 0.05 thermal 0.188 (3/16) b	a (1/17) 0.059 0.700 (21/30) b	a (17/22) 0.773 3.00 (30/10) b
B	a (32/381) 0.084 0.545 (42/77) b	a (105/156) 0.673 0.516 (95/184) b	a (108/52) 2.077 1.845 (120/65) b
C	a (11/119) 0.092 0.667 (8/12) b	a (11/100) 0.110 0.179 (7/39) b	a (0/0) 0.00 0.00 (0/0) b

Degree 2:

	U1	U2	U3
A	a (0/80) 0.00 0.125 (2/16) b	a (2/17) 0.118 0.20 (6/30) b	a (0/22) 0.00 1.10 (11/10) b
B	a (6/381) 0.016 0.429 (33/77) b	a (13/156) 0.083 0.163 (30/184) b	a (28/52) 0.538 0.323 (21/65) b
C	a (1/119) 0.008 0.417 (5/12) b	a (3/100) 0.030 0.154 (6/39) b	a (0/0) 0.00 0.80 (8/10) b

Degree 3:

	U1	U2	U3
A	a (1/80) 0.013 0.00 (0/16) b	a (0/17) 0.00 0.067 (2/30) b	a (0/22) 0.00 0.20 (2/10) b
B	a (1/381) 0.003 0.013 (1/77) b	a (1/156) 0.006 0.00 (0/184) b	a (3/52) 0.057 0.046 (3/65) b
C	a (0/119) 0.00 0.00 (0/12) b	a (0/100) 0.00 0.00 (0/39) b	a (0/0) 0.00 0.00 (0/10) b

TABLE 2 - DISTURBANCE FREQUENCY BY UTILITY CHARACTERISTICS

Figure 1 shows the overall performance results of all reporting utilities, irrespective of their utility characteristics. On average, the utilities have experienced one Degree 1 Disturbance approximately every 2 1/2 years, one Degree 2 Disturbance approximately every 8 years, and one Degree 3 Disturbance every 100 years.

Figure 2 shows the average performance of utilities grouped by their characteristics. The results indicate that thermally limited systems (denoted as "a") experience fewer disturbances in all Degrees of Severity than stability limited systems (denoted as "b"). The figure also shows that isolated systems (U3) have significantly more Degree 1 and Degree 2 Disturbances per year than those of U1 and U2 types.

The Degree 1 and Degree 2 Disturbance Frequencies of the large utilities (SSF A) are about the same as the SSF B utilities and are higher than the small utilities (SSF C). These results, however, must be treated with some caution, since about 70% (53/76) of the Degree 1 Disturbances are contributed by three SSF A utilities out of a total of 20 such utilities. Similarly, eight SSF B utilities out of a total of 110 have contributed about 50% (253/502) of the Degree 1 Disturbances.

All of the Degree 3 Disturbances have occurred on systems of size A and B. A possible explanation for this result is that the restoration process of large systems may be more complex than that of smaller systems.

Figure 3 illustrates the results of thermal and stability limited systems for each system size. It is evident that within each System Size Factor, the stability limited systems have a much higher Disturbance Frequency than thermally limited systems. The Degree 1 Disturbance Frequency of stability limited systems decreases as the System Size decreases, while the Disturbance Frequency of thermally limited systems does not vary markedly with the System Size Factor.

Comparison of the interconnection relationship with the system size and the system limitation, indicates, perhaps not surprisingly, that interconnected systems have better performance than isolated systems regardless of system size and system limitation.

The range of utility performance relative to utility characteristics is illustrated in the next three figures. Degree 1 Disturbance Frequency plotted against the percent of utilities are grouped by:

- (1) System Size Factor (Figure 4),
- (2) Thermal/Stability Limitation (Figure 5),
- (3) Interconnection Relation (Figure 6).

An example on how to interpret the results is given in the top right-hand corner of Figure 4. The horizontal axis is a normal probability scale.

Although the average frequency of Degree 1 Disturbances for utilities of SSF A characteristic is 0.434 (Figure 2), Figure 4 shows that only three utilities (15%) of SSF A have a frequency of one or more Degree 1 Disturbances per year. Furthermore, 75% have experienced better than average performance.

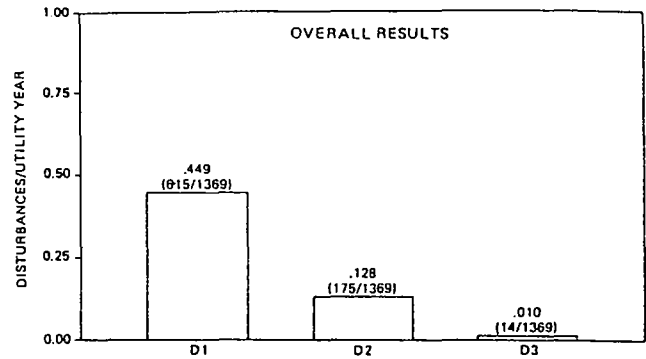


FIGURE 1 - OVERALL RESULTS OF BES DISTURBANCES

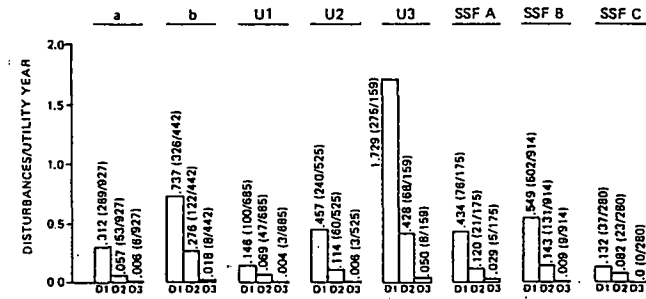


FIGURE 2 - RESULTS BY UTILITY CHARACTERISTICS

The same analysis can be made for the other characteristics. Using these figures, a utility can compare its performance to the range experienced by other utilities with similar characteristics.

Figures 2 and 6 show that utilities which are isolated, that is, Type U3, have a very high frequency of Degree 1 Disturbances. To examine the significance of their impact on overall performance, results are shown in Figure 7 with the data for U3 utilities removed.

A comparison between Figure 2 and Figure 7 shows that the Degree 1 Disturbance Frequency for both thermally and stability limited systems is reduced by 38% and 33% respectively. The stability limited systems, however, still show a higher Disturbance Frequency than thermally limited systems for all Degrees of Severity. In addition, the Degree 1 Disturbance Frequency for different system sizes shows a marked change in magnitude. SSF A, without U3 utilities, has its Degree 1 Disturbance Frequency reduced by approximately 53%. SSF B, without U3 utilities, has its Degree 1 Disturbance Frequency reduced by approximately 37%.

Figure 8 illustrates, for each utility classification, the percent of utilities that have "perfect" performance in all three Degrees of Severity, (ie, reported zero Degree 1, 2, and 3 Disturbances). Forty-four percent of all utilities have reported perfect performance. The pattern of results supports the observations made previously.

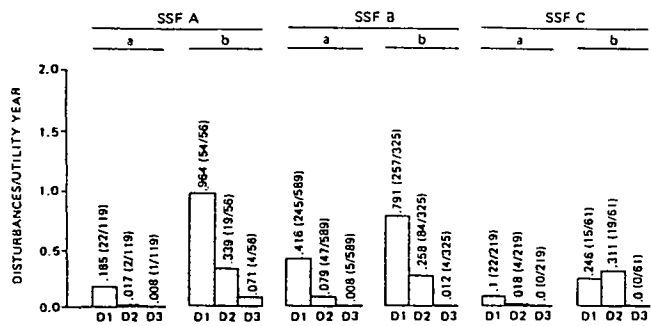


FIGURE 3 - COMPARISON OF THERMAL (a) AND STABILITY (b) LIMITATION FOR EACH SYSTEM SIZE FACTOR

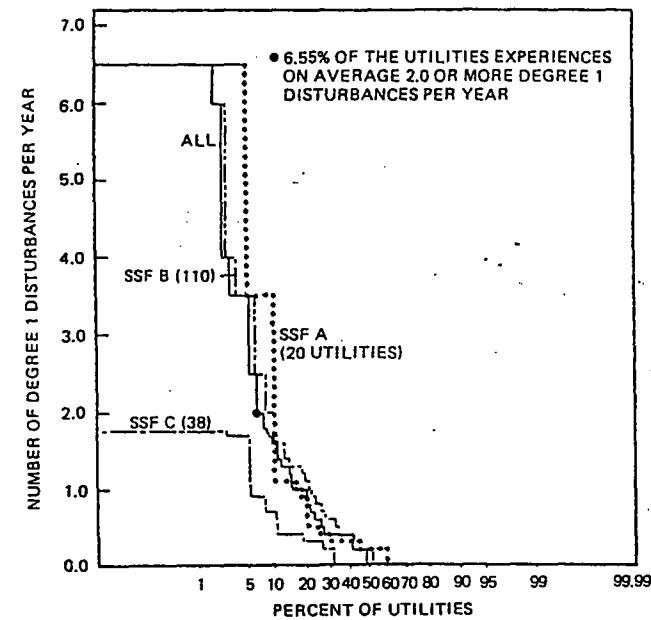


FIGURE 4 - DEGREE 1 DISTURBANCES GROUPED BY SYSTEM SIZE FACTOR

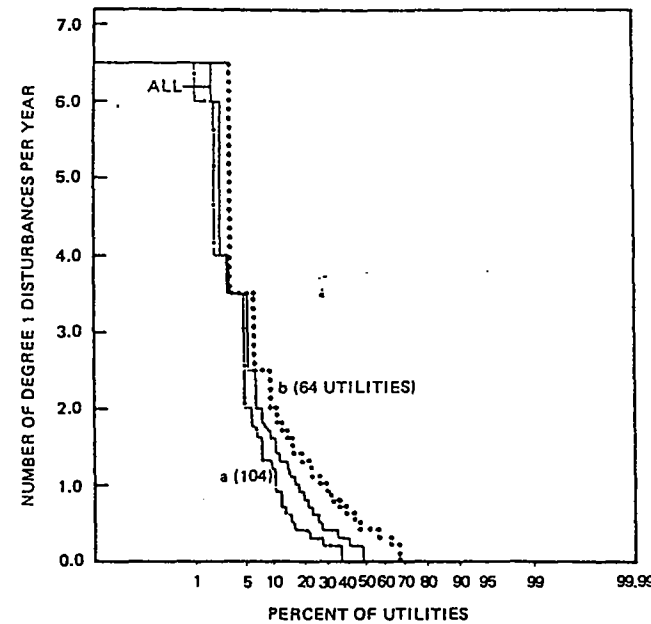


FIGURE 5 - DEGREE 1 DISTURBANCES GROUPED BY THERMAL/STABILITY LIMITATION

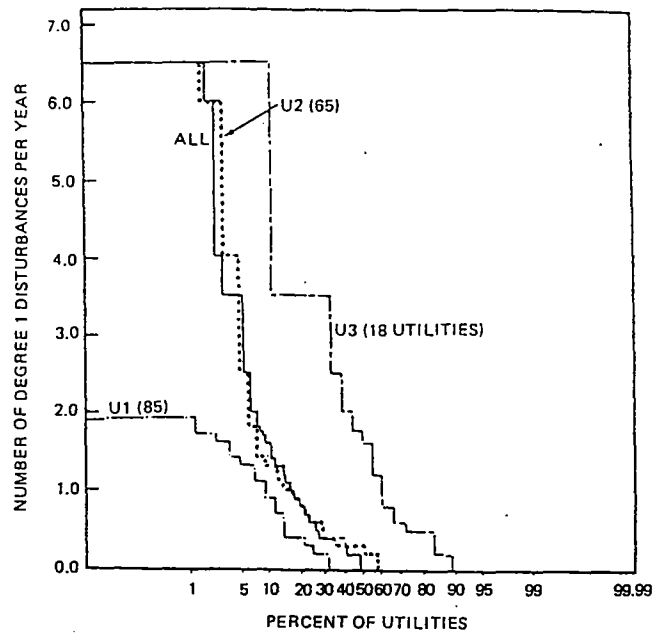


FIGURE 6 - DEGREE 1 DISTURBANCES GROUPED BY INTERCONNECTION RELATION

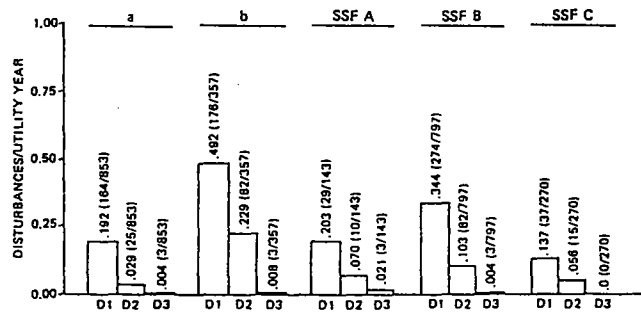


FIGURE 7 - RESULTS EXCLUDING ISOLATED SYSTEMS (U3)

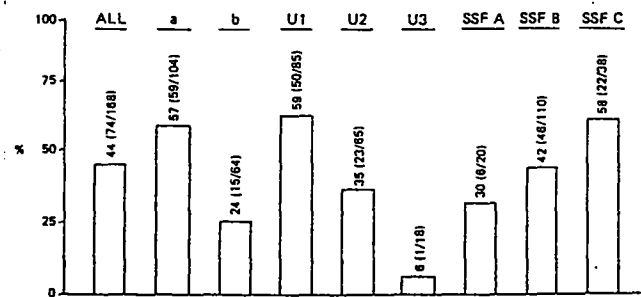


FIGURE 8 - UTILITIES WITH "PERFECT" PERFORMANCE GROUPED BY UTILITY CHARACTERISTICS

There were sufficiently large numbers of responses from Europe and North America to warrant separating out the performance results of utilities on the two continents. As shown in Figure 9, they have approximately the same Disturbance Frequency, on average, for all Degrees of Severity.

This also holds true for the range of performance experienced by the utilities on the two continents, as shown by Figure 10.

Subsequent to the preparation of the paper, an additional study of the survey responses was undertaken to observe the change in performance through time. The results (Figure 11), as reported at the 1986 SC39 Session meeting, show an increasing trend for Degree 1 Disturbances. There was insufficient data to analyze Degree 2 or Degree 3 performance trends.

In 1987, the Working Group published in *Electra* an article entitled "Further Analysis of Disturbance Performance on Bulk Electricity Systems"[6], which described application of the segmentation method to the data in the survey results. The analysis supported and provided additional insight to the observations in the paper.

It was concluded statistically that system location (interconnection) has the biggest influence on system disturbance performance, followed by the system limitation and then system size.

#### 2.4 Summary

On average, utilities have experienced one Degree 1 Disturbance approximately every 2 1/2 years (ie, 40 per 100 years), one Degree 2 Disturbance approximately every 8 years (ie, 12 per 100 years), and one Degree 3 Disturbance every 100 years.

A number of observations have been made on the differences in disturbance performance in terms of the utility characteristics. These observations are based on the average performance of the utilities grouped by combinations of their characteristics. There is considerable dispersion about the averages and some of the groups contain relatively few utilities. The observations are therefore of a general and approximate nature.

- Interconnecting with neighbouring utilities is an important factor in lowering the frequency of Degree 1 Disturbances, especially for large systems (SSF A).
- Stability limited systems have experienced significantly more disturbances in all Degrees of Severity than thermally limited systems.
- Larger systems (SSF A and SSF B) have a similar number of disturbances in all Degrees of Severity while smaller systems (SSF C) have significantly fewer disturbances.
- Statistically, it has been shown that system location (interconnection) has the biggest influence on performance, followed by system limitation and the system size.

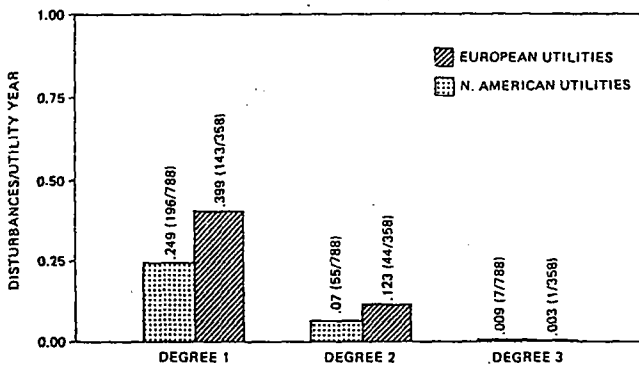


FIGURE 9 - RESULTS BY GEOGRAPHICAL AREA

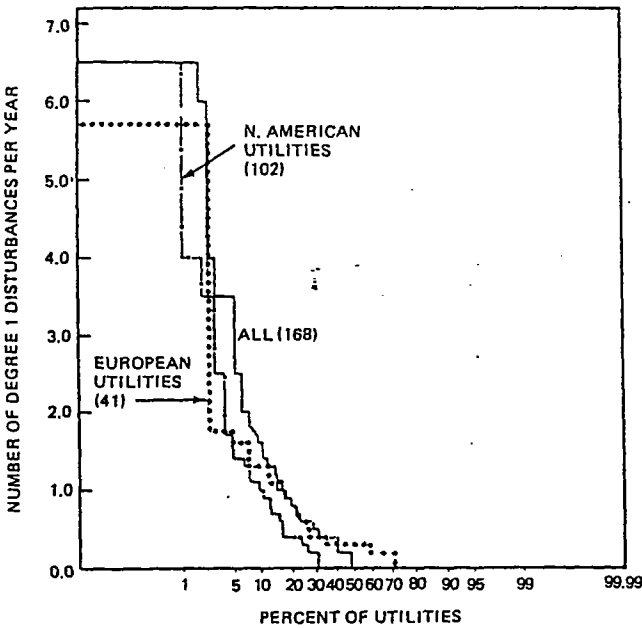


FIGURE 10 - DEGREE 1 RESULTS GROUPED BY GEOGRAPHICAL AREA

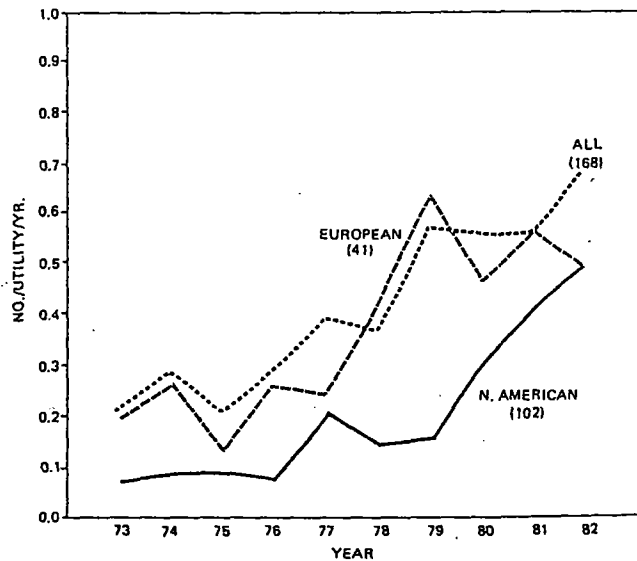


FIGURE 11 - TRENDS IN DEGREE 1 DISTURBANCE PERFORMANCE

- No Degree 3 Disturbance has been recorded for SSF C systems, possibly because restoration processes are less complex.
- North American and European utilities have approximately the same Disturbance Frequency in all Degrees of Severity.
- The frequency of Degree 1 Disturbances has been increasing through time.

A total of 74 utilities reported zero disturbances in all three Degrees of Severity; in other words, 44% of all responding utilities experienced no Degree 1, 2 or 3 Disturbances over the 10-year period.

### 3.0 QUALITY

Quality is defined as the supply to customers at any time of sufficient energy at defined quality levels of voltage and frequency.

### 3.1 BES Delivery Points

From the standpoint of BES operational management, the "customers" are interconnected utilities and the distribution systems. The busbars at the BES interfaces with these customers are designated as "Delivery Points."

#### 3.1.1 Measurement System

CIGRE SC 39 adopted a measurement system consisting of a classification system for Delivery Points, and a data collection system. The classification system is illustrated in Figure 12.

The BES supplies four types of Delivery Points:

- Type A busbars that supply electricity to a distribution system which is operated as a radial network without local production, such that an interruption of supply to the busbar will result in customer interruption. (The low voltage busbar at stepdown transformer stations where the voltage is stepped down from a transmission voltage or subtransmission voltage in the range of 50-150 kV to a distribution voltage of under 50 kV but above 5 kV.)

- Type B busbars that supply electricity to a distribution system which is operated as a meshed network. Interruption of a Type B busbar does not necessarily result in customer interruption. The load may be supplied partly or completely by alternate transmission and distribution facilities or local production. (The low voltage busbar at stepdown transformer stations where the voltage is stepped down from a transmission voltage or subtransmission voltage in the range of 50-150 kV to a distribution voltage of under 50 kV but above 5 kV.)

- Type C busbars that supply electricity to a neighbouring BES.

- Type D busbars internal to the BES. A utility may wish to monitor the performance of other important busbars in its system, such as those which are important to the reliability of supply of busbars in categories A, B, C, or some other critical load.

Two examples of switching arrangements, which illustrate the difference between Type A and Type B Delivery Points, are provided in Figure 13.

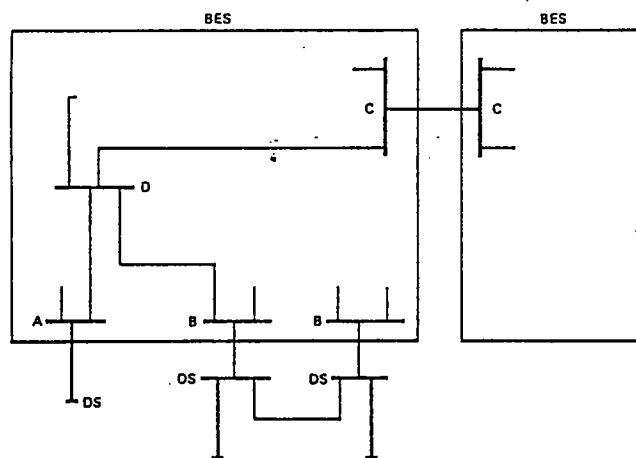
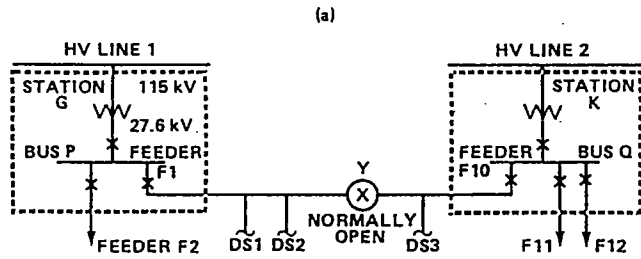
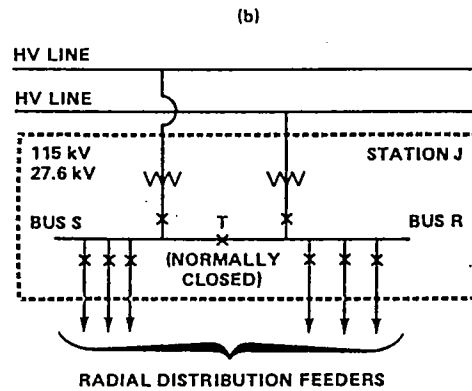


FIGURE 12 – ILLUSTRATION OF BES DELIVERY POINT CLASSIFICATION SYSTEM



BUSES P AND Q ARE TYPE A

NOTE IF POINT Y IS OPERATED CLOSED THIS WOULD BE CONSIDERED A MESHED DISTRIBUTION NETWORK AND BUSES P AND Q WOULD BE TYPE B



ALTHOUGH BUSES S AND R ARE CONNECTED AT THE STATION J THROUGH BUS TIE BREAKER (T), THE BUSES ARE INDIVIDUALLY SWITCHED FOR FAULTS AND BUSES S AND R ARE TYPE A

FIGURE 13 – EXAMPLES OF DELIVERY POINT CLASSIFICATION AS RELATED TO DISTRIBUTION NETWORKS

The data collection system consists of a record, for each BES delivery Point interruption, of the following:

- The type of busbar (A, B, C, or D).
- The date and time of the interruption.

A busbar is considered interrupted when its voltage supply is interrupted.

- The duration of each interruption, in accordance with the following convention.

The duration of an interruption should be recorded to the nearest minute. A duration of zero (0) minutes should be used for those interruptions which are restored by automatic reclosure facilities. These are referred to as Momentary Interruptions. The shortest restoration time for interruptions that are restored manually would then be 1 minute. These are referred to as Sustained Interruptions. This convention recognizes the generally quicker restoration achieved by automatic reclosure facilities and will allow a distinction to be made between these two types of restoration processes.

- Associated customer load interrupted (MW) and energy not supplied (MW-Minutes).

This system permits the following basic performance indices to be derived for each class of Delivery Point:

- Frequency of Interruptions Per Year (Momentary and Sustained)
- Duration of Sustained Interruptions Per Year
- Mean Duration of Sustained Interruptions
- Severity of Events (in System Minutes)
- Unsupplied Energy Per Year

BES product quality is affected as a result of generation events, BES Disturbances or loss of transmission continuity. BES Delivery Point performance reflects all such events if the result or action taken is at the Delivery Point level. It thus includes Delivery Point interruptions resulting from BES Disturbances and rotational load shedding if effected by interrupting complete Delivery Points. It does not include the effect of BES unreliability events where action is taken downstream of the Delivery Point, eg, rotational load shedding achieved by opening individual feeder breakers on distribution systems.

### 3.1.2 Survey

An international survey was conducted in 1986. In order to keep it as simple as possible, and thus to encourage the maximum number of responses, the recipients of the survey were requested to provide data for only Type A and Type B Delivery Points, and for only the total number and total duration of interruptions of 1 minute durations or longer for 1985, ie, interruptions restored by automatic reclosure were excluded.

The survey response summary is shown below. It includes the results for 19 586 Delivery Points supplied by 72 utilities in 23 countries. Thirty-four utilities had only Type A Delivery Points whereas four had only Type B. Type B Delivery Points represent only about 9% of the

total population of Delivery Points. The number of Delivery Points for reporting utilities varies over a wide range, with the smallest having less than 10 Delivery Points and the largest over 1 800.

	No. of Utilities	No. of Type A DPs	No. of Type B DPs	Total No. of DPs
North				
American	37	9 690	834	10 524
European	22	5 188	784	5 972
Other	13	2 952	138	3 090
Total	72	17 830	1 756	19 586

### 3.1.3 Survey Results

Results were reported in a paper[7] presented at the 1988 Session. Three parameters were used to assess BES Delivery Point performance, ie:

Interruption Frequency - The number of interruption events per Delivery Point during a specified period of time (in this survey 1 year).

Interruption Duration - The duration expressed as minutes per year that a Delivery Point is interrupted during a specified period of time (in this survey 1 year).

Restoration Time - The time in minutes to restore the BES supply to a Delivery Point following an interruption.

Average values of these parameters were calculated for the complete set of Delivery Points and for various subsets, ie:

$$\text{Average Interruption Frequency for a Group of Delivery Points} = \frac{\sum \text{Delivery Point Interruptions}}{\sum \text{Delivery Points}}$$

$$\text{Average Interruption Duration for a Group of Delivery Points} = \frac{\sum \text{Delivery Point Interruption Durations}}{\sum \text{Delivery Points}}$$

$$\text{Average Restoration Time for a Group of Delivery Points} = \frac{\sum \text{Delivery Point Interruption Durations}}{\sum \text{Delivery Points Interruptions}}$$

It should be noted that the Average Interruption Duration can be derived from multiplying the Average Interruption Frequency and the Average Restoration Time.

When a subset comprises all the Delivery Points of one utility the averages are referred to as the:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- System Average Restoration Index (SARI)

As shown in Figures 14, 15, and 16, Delivery Points were found to be interrupted about once every 2 years with an average annual duration of about 36 minutes. Once interrupted, Delivery Points were restored on average after 73 minutes.

Type A Delivery Points, those supplying radial distribution networks, experience about 60% more interruptions than Type B. However, their restoration time is considerably less.

Shorter restoration times for Type A Delivery Points may be attributed to the fact that all customer load is interrupted when the Delivery Point is interrupted. BES supply restoration then proceeds as quickly as practicable. The same urgency may not exist for Type B Delivery Points supplying a meshed network in which customers are not necessarily interrupted.

The distributed performance of the Delivery Points is shown in Figures 17 and 18. As there was a significant number of responses from North America and Europe, performance of Delivery

Points in each of these continents is also illustrated. It should be noted, however, that the survey responses do not provide comprehensive coverage.

Figure 17 displays the cumulative distribution of Delivery Points with respect to Interruption Frequency. The majority of the Delivery Points (76.1%) did not experience any interruptions and only 9.4% (ie, 1 832 out of 19 586) of all the Delivery Points had two or more interruptions. This is encouraging since utilities wishing to improve their performance need only to concentrate their efforts to a small percentage of their Delivery Points.

Figure 18 displays the distribution with respect to Interruption Duration. Interruption durations vary from 0 to 18 121 minutes for the year, (the extreme duration possibly being attributable to a non-urgent restoration). Only 10% of all Delivery Points were interrupted for more than 50 minutes for the year.

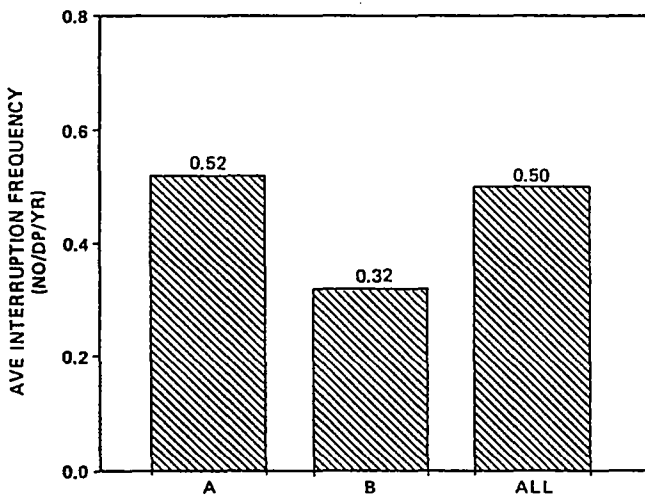


FIGURE 14 – AVERAGE INTERRUPTION FREQUENCY

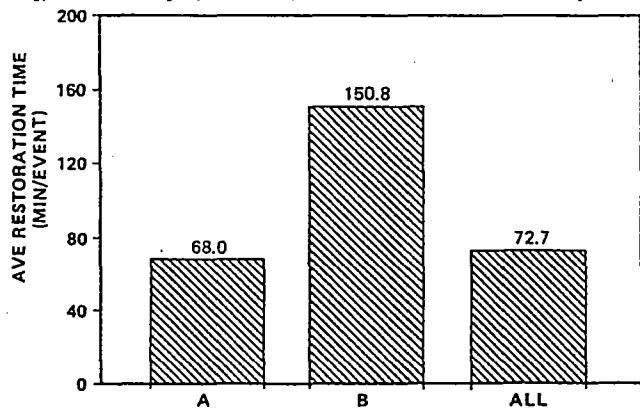


FIGURE 16 – AVERAGE RESTORATION TIME

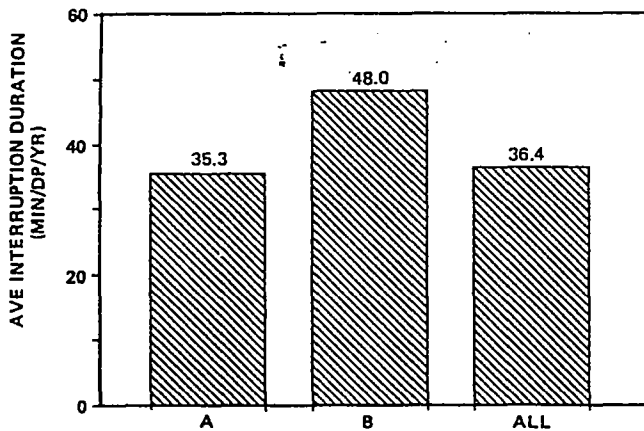


FIGURE 15 – AVERAGE INTERRUPTION DURATION

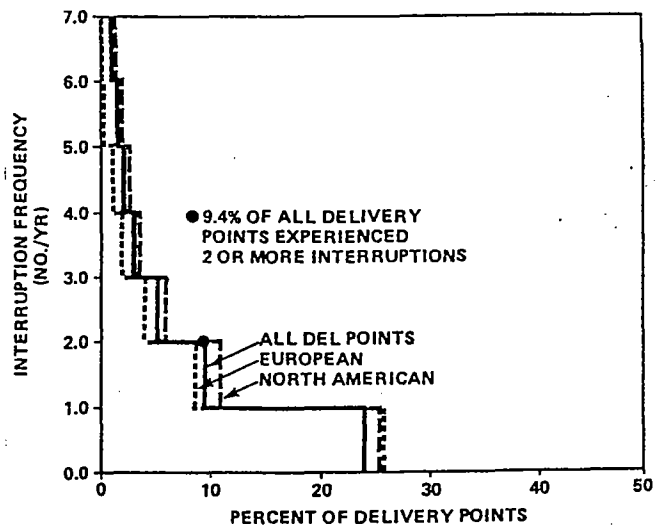


FIGURE 17 – CUMULATIVE DISTRIBUTION OF DP PERFORMANCE (INTERRUPTION FREQUENCY)

Figures 19 to 21 display the distribution of utility performance for SAIFI, SAIDI, and SARI. From Figure 29, it can be seen that there is a fairly wide range in the SAIFI which varies from 0.0 to 7.85 among the utilities. Eighty-five percent of the utilities had a SAIFI of less than one interruption per year.

Figure 20 shows the distribution of SAIDI. It also shows a wide range in performance among the utilities, varying from as low as 0 to a high of 561 minutes per year.

SARI is shown in Figure 21. While a few utilities experienced a relatively high SARI, 68% of all utilities had an index below the overall average of 75.7 minutes per interruption.

Figure 22 displays the mean, lower, and upper deciles and quartiles of the set of utility distributions for Delivery Point Interruption Duration.

A utility wishing to compare its performance with that of other utilities could do so by plotting its distribution on this figure, as indicated by the line for a hypothetical utility identified as utility X.

Similarly, Figure 23 displays the utility percentiles of Delivery Point Interruption Frequency.

An examination was made of the correlation between the average duration per Delivery Point interruption and the total number of interruptions. The results are shown in Figure 24 and a negative correlation is evident.

This suggests, as may be expected, that utilities may be willing to accept a higher interruption frequency if the duration per interruption is low.

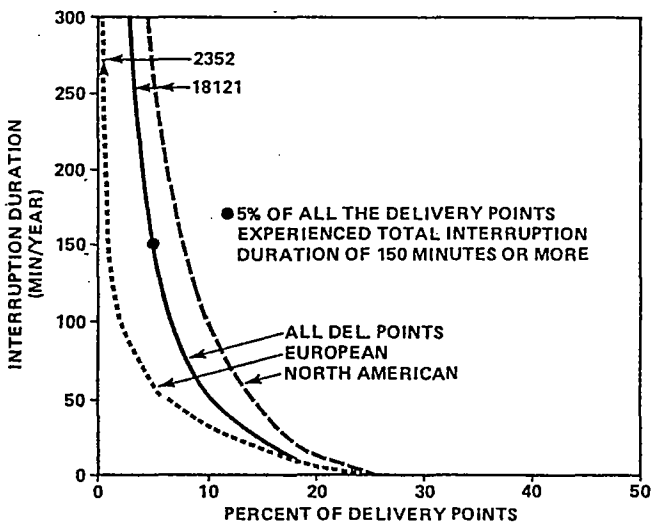


FIGURE 18 - CUMULATIVE DISTRIBUTION OF DP PERFORMANCE (INTERRUPTION DURATION)

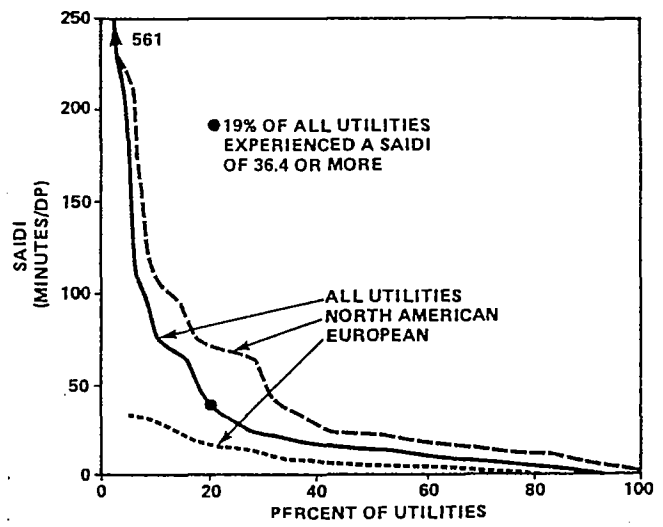


FIGURE 20 - CUMULATIVE DISTRIBUTION OF UTILITIES BASED ON SAIDI PERFORMANCE

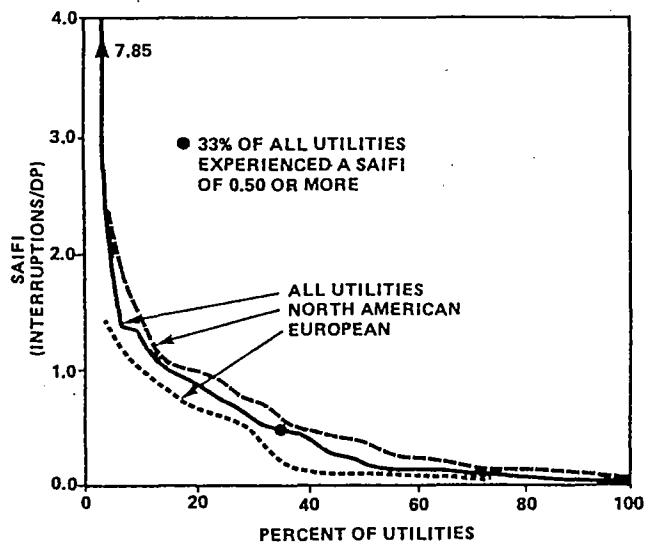


FIGURE 19 - CUMULATIVE DISTRIBUTION OF UTILITIES BASED ON SAIFI PERFORMANCE

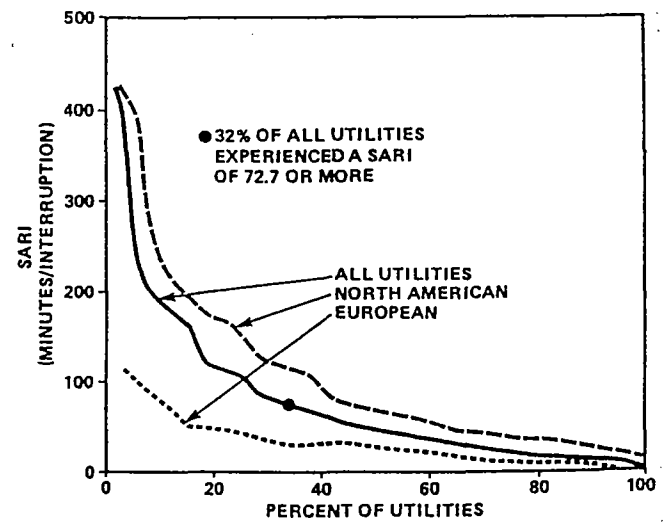


FIGURE 21 - CUMULATIVE DISTRIBUTION OF UTILITIES BASED ON SARI PERFORMANCE

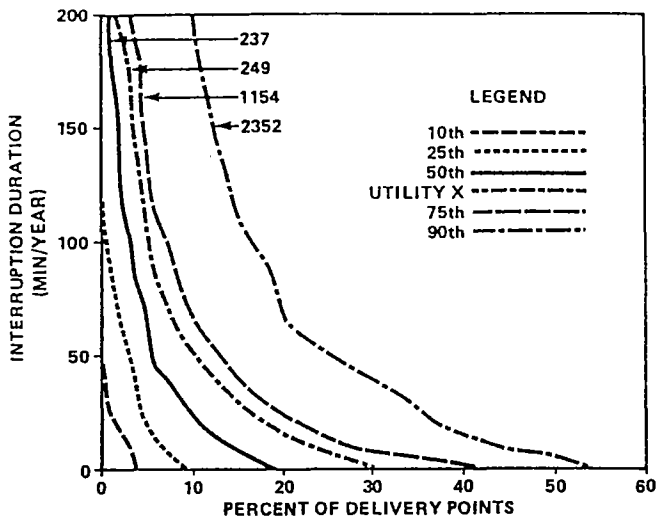


FIGURE 22 – UTILITY PERCENTILES OF TOTAL INTERRUPTION DURATION

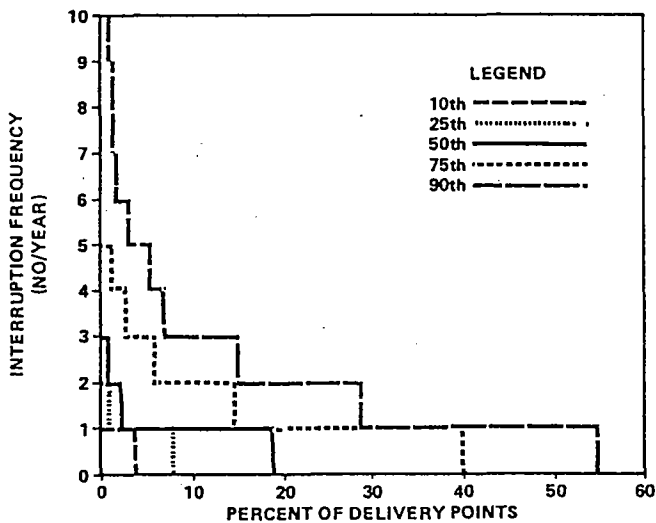


FIGURE 23 – UTILITY PERCENTILES OF TOTAL INTERRUPTION FREQUENCY

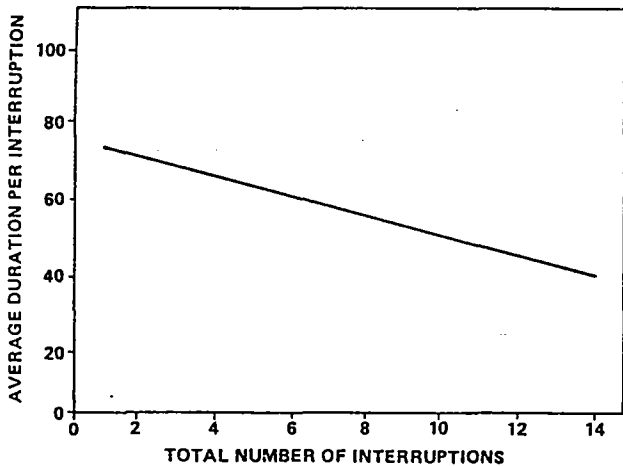


FIGURE 24 – CORRELATION OF NUMBER OF INTERRUPTIONS VERSUS AVERAGE DURATION PER INTERRUPTION

The data collected in the survey were for one year only, 1985. To determine if there was any evidence that utility performance is changing through time comparisons were made using data from four utilities that responded to the survey reported at the 1980 Session<sup>[2]</sup>, and were able, on short notice, to provide data for the period 1982 to 1986. Due to the limited sample size, however, no conclusions could be drawn.

### 3.1.4 Summary

The result of the CIGRE SC39.05 survey of BES Delivery Point Interruptions has been the establishment of an extensive data base providing Delivery Point Performance information hitherto not available in the utility industry. The 72 utilities whose responses form the basis of this analysis represent a wide cross section of the international community.

Performance has been differentiated on the basis of function, i.e., supplying meshed or radial distribution, by geography and by utility, thus providing some insight into BES performance variations and enabling individual utilities to assess their Delivery Point performance relative to others.

The following general observations highlight the Delivery Point survey results:

- A Delivery Point is interrupted, on average, once every two years for about 73 minutes.
- The majority of Delivery Points (76.1%) did not experience any interruptions.
- Type A Delivery Points had, on average, 60% more interruptions, but 25% shorter interruption duration, than Type B.
- On average, Delivery Points in North America had a somewhat higher interruption frequency and longer interruption duration than those in Europe.

### 3.2 BES Frequency Quality

Two aspects of BES frequency performance were considered:

- (1) Normal frequency variations, i.e., variations from nominal value that are normally experienced by customers (typically less than 0.5% from nominal).
- (2) Frequency deviation events. A deviation of 0.5% or more from the nominal of part or all of a system for 1 minute or more was defined as a Frequency Deviation Event (FDE). For large interconnected systems, these generally would be observed only when an electrical island is formed. For smaller isolated systems, loss of a large generating unit may be sufficient to initiate such an event.

#### 3.2.1 Measurement System

For normal frequency variations it was decided simply to record the frequency provided by the utility industry in the form of a set of curves of cumulative distribution of system frequency for one year. A system in this context is either an isolated utility or an interconnected system comprised of two or more utilities.

The Frequency Deviation Index (FDI) was developed to assess the second aspect of frequency quality, i.e., frequency deviation events. This index measures the amount of a utility's load that is subjected to one-half percent intervals of frequency departure from normal, and the duration. More specifically:

$$FDI = \sum (L \times D \times Fd) \text{ for each frequency departure interval in each event}$$

L = load affected (percent of total utility load)

D = duration (minutes)

Fd = frequency deviation (mid-point of interval in percent of nominal, i.e., 0.75 for the interval between 0.5% and 1.0% of nominal)

A Frequency Deviation Index of one is the equivalent of the total system load experiencing a frequency deviation of 1% from nominal for 1 minute.

### 3.2.2 Survey

A survey of Study Committee 39 members was conducted in 1987.

For normal variations the members were asked to respond on a system basis, as defined above.

Responses were received from eight systems varying in size from 2 000 MW to 330 000 MW of peak demand. The data were for 12-month periods within the 1985 and 1986 calendar years.

With respect to Frequency Deviation Events (FDE), utilities were requested to provide data on the duration and percent of load experiencing frequency deviations greater than  $\pm 0.5\%$ ,  $\pm 1.0\%$ ,  $\pm 1.5\%$ , etc, from nominal for each FDE in a 1-year period. Twelve replies were received giving data on 332 FDE.

### 3.2.3 Survey Results

The results of the survey were reported at the 1988 Session<sup>[7]</sup>. Figure 25 shows the frequency distribution of each of the responding systems.

Due to two nominal frequencies being in use (50 Hz and 60 Hz), variations are expressed as per unit of nominal.

Frequency is controlled within  $\pm 0.005$  pu 98% of the time. In general, and as might be expected, frequency quality varies more or less inversely with system size.

The responses to the frequency deviation survey are summarized in Table 3.

The first six utilities are parts of large interconnected systems. The percentage of utility load involved in Frequency Deviation Events was small, typically 1%. For these utilities, an FDE would likely only occur in an islanding situation.

The remaining utilities are isolated or part of a small interconnection whose entire loads are usually affected during an FDE.

There is a very significant difference in the performance of these two groups of systems. Also, there are significant performance differences within the second group.

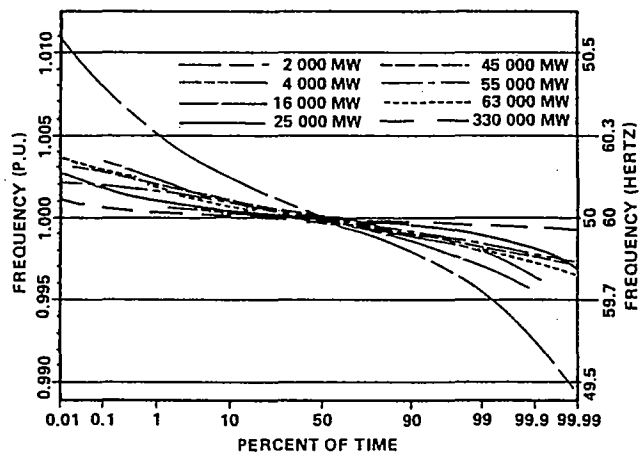


FIGURE 25 – CUMULATIVE DISTRIBUTION OF FREQUENCY

Utility	Number of FDEs	Total Duration (Minutes) for Deviation of					Utility or System Peak Demand (MW)	Associated Interconnection Peak Demand (MW)	FDI
		0.5–1%	1–1.5%	1.5–2%	2–2.5%	2.5–3%			
1	0	0	0	0	0	0	17 500	91 000	0
2	0	0	0	0	0	0	5 000	55 000	0
3	0	0	0	0	0	0	20 000	55 000	0
4	1	0	0	22	0	0	5 000	55 000	0.5
5	0	0	0	0	0	0	9 500	225 000	0
6	10	3	44	26	5	0	20 000	330 000	0.4
7	2	12	5	4	0	0	2 000	2 000	21
8	9	16	17	4	4	1	4 000	4 000	50
9	49	84	0	0	0	0	8 000	15 000	63
10	60	307	24	16	0	0	1 200	1 200	267
11	126	528	140	12	0	0	16 000	16 000	600
12	75	142	0	0	0	0	45 000	45 000	107

TABLE 3 – FREQUENCY DEVIATION RESULTS

### 3.3 BES Voltage Quality

The Working Group identified the following list of parameters considered relevant to the provision of satisfactory voltage quality to ultimate customers:

- (1) variation of steady-state voltage,
- (2) random voltage fluctuations (voltage dips and spikes),
- (3) voltage flicker,
- (4) phase voltage unbalance, and
- (5) harmonic content

However, no clear direction for a voltage quality measurement system emerged from discussions in the Working Group.

#### 3.3.1 Survey

To broaden the search, a survey was conducted amongst members of Study Committee 39 in 1987. The survey requested utilities to provide the following information with respect to the

parameter listing above:

- list of measurement systems currently in use
- list of acceptable limits or standards
- performance results

Thirteen utilities responded to the survey.

#### 3.3.2 Survey Results

The survey results reported at the 1988 Session<sup>[7]</sup> are summarized in Table 4. It was concluded that most utilities do not measure the voltage quality provided to customers by BES as such. Most BES voltage measurements and standards relate to the acceptability of conditions within the BES itself, i.e. relate to equipment ratings, validity of security limits, etc.

In general, voltage dips and spikes, flicker, phase voltage unbalance, and harmonic content are not monitored as they occur mainly at distribution voltage levels.

#### STEADY STATE VOLTAGE PERFORMANCE

STEADY STATE VOLTAGE PERFORMANCE		OTHER FACTORS
Measurement Devices in Addition to Operating Metering	Operating Voltage Limits	(Fluctuations, Flickers, Unbalance, Harmonics)
1. - Disturbance Recorders	- ± 10 percent	- None identified
2. - Off-line measurements	- Normally + 8 percent, - 6.5 percent, ± 10 percent with loss of single element	- None identified
3. - Voltage charts	- ± 5 percent customers < 25 kV ± 10 percent customers > 25 kV ± 5 percent on BES	- Some harmonics problems relating to feeders in industrial customer
4.	- Usually + 10 percent, - 5.0 percent on BES	- Installing measuring system for dips, spikes flicker at key locations - Phase voltage imbalance in industrial areas - Regular sampling of waveform in identified problem areas
5.		- Daily measurements at four locations of phase voltage imbalance - Flicker investigated on as needed basis
6. - Digital records, each 5 min and fault recorders		- Accessed as needed - No problems except under fault conditions
7.	- Varies with voltage level of BES equipment	- Problems do occur at distribution levels
8.	- ± 5 percent at Delivery Points	- Considering recording of duration of time that voltage variation > ± 5.0 percent of each delivery point
9. - Voltage recorders at some main substations - Hourly voltages digitally stored at Control Centre	- Varies with voltage level on BES	- Measurements where needed - One continuous measurement of harmonics at 400 kV
10.	- Varies with voltage level	- Recrd number of customer complaints attributable to BES - Measurements taken when problems occur, usually on distribution system
11. - Voltage recorders at main substations	- Upper limit of + 10 percent - Alarms at - 2 percent	- Investigated when needed
12.		- Phase voltage unbalance and voltage fluctuations monitored where needed
13. - Voltage recorders at main substations	- ± 6 percent at Delivery Points	- Limits exist for voltage fluctuations, flickers, phase voltage unbalance and voltage harmonics - Measurement taken as needed

TABLE 4 - SUMMARY OF VOLTAGE SURVEY REPLIES

4.0 MEASURES OF COST PERFORMANCE

A survey was conducted of SC39 members to determine the types of BES operational cost performance measurements being used. The measures fell into three main categories, ie, global, operationally-comprehensive and utility-specific.

The global measures, such as the unit energy price of energy delivered by the utility, or the cost of the output of a particular type of generation, are regarded as being less useful to operational management than the other types of measures, but are recorded because such measures are often employed to judge utilities by those outside the business.

Their use should be treated with caution, because global measurements can conceal important information about the individual programs within the global program. As examples:

- inadequate maintenance can appear as a short term efficiency improvement.
- overall costs could decrease if a sub-program costs are increased eg, hydraulic efficiency expenditures on a hydro-thermal system,
- overall staff per unit of production can increase if economic new generation is more labour intensive than existing generation.

Within the limited set of utilities covered by SC39 membership, there are several operationally-comprehensive costs measurement systems in use. In general terms, these systems track actual operational costs relative to computed ideal cost, and divide the difference into categories that, by magnitude, indicate where a management focus is warranted or that, by trend, indicate improving performance or otherwise. The users of these systems made the point that it is inappropriate to use the measurement results for inter-utility comparisons as they are very dependent upon the characteristics of the individual utility eg, type of load served, type of generation installed.

Three such systems will be described.

Many utility-specific cost measures were reported, and a comprehensive listing has been included. This should prove useful to those wishing to introduce a new measurement system or to expand an existing system.

4.1 Operational-Comprehensive Measurement Systems

The three utilities that employ operationally-comprehensive measurement systems are Ontario Hydro (Canada), SEP (Netherlands) and EGAT (Thailand). Following is a brief description of their systems.

4.1.1 Ontario Hydro's Operational Cost of Fuel Used

Ontario Hydro uses both direct and indirect measures to assess its performance in the Product Cost area. The description which follows is for a system to measure the Operational Cost of Fuel Used (OCFU). A conceptual illustration of the OCFU measurement system is shown in Figure 26.

OCFU is composed of three main cost components. The first component is related solely to the actual energy and capacity demands and it assumes theoretically ideal operation of an intact production and transmission system; that is, it assumes perfect human, system, and equipment performance. This component is termed the Base Cost of Fuel Used (BCFU) and it represents the absolute minimum fuel cost to meet these demands for the period under consideration. As such, it is beyond attainment.

The second component is related to those additional fuel costs which result from transmission-associated constraints. These are considered to fall into two categories. Firstly, there are those resulting from consideration of the maximum power transfer capability of an individual transmission component or group of components and, secondly, there are those resulting from the electrical losses associated with the transmission of electrical energy.

Transmission Outage Costs (TOC) and Security Limits Dispatch Costs (SLDC) fall within the first category. They are the result of either the higher replacement cost of bottled capability or the out-of-merit running of generating plant for security considerations. The category of TOC is limited to those costs incurred due to any constraint resulting from a transmission outage or derating on the BES. The category of SLDC is limited to those costs incurred due to any transmission constraint on the BES which is inherent in the intact (both in terms of circuit elements and of element capability) transmission system, ie, any constraint which is not the result of a transmission outage or derating.

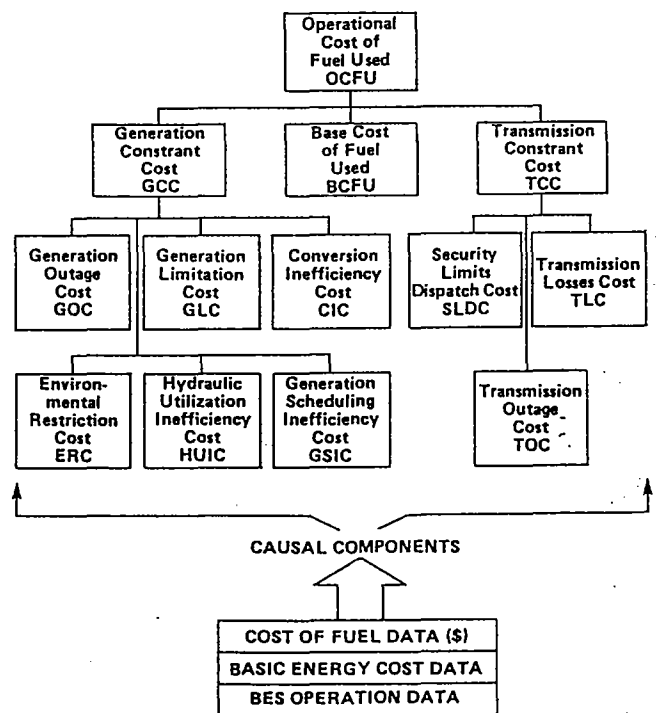


FIGURE 26 - CONCEPTUAL ILLUSTRATION OF OCFU MEASUREMENT SYSTEM

Transmission Losses Costs (TLC) come within the second category. They represent the difference between the power entering the transmission system and that leaving it at the BES Delivery Points and secondary sales interfaces.

The third component is related to those additional fuel costs which result from generation-associated constraints. Again, these are considered to fall into two categories. Firstly, there are those resulting from limitations directly related to the generating plant and, secondly, there are those resulting from limitations indirectly related to the generating plant. The first category encompasses the components of Generation Outage Costs (GOC), Generation Limitation Costs (GLC), and Conversion Inefficiency Costs (CIC). The second category encompasses the components of Environmental Restriction Costs (ERC), Hydraulic Utilization Inefficiency Costs (HUIC), and Generation Scheduling Inefficiency Costs (GSIC).

Generation Outage Costs and Generation Limitation Costs result from either the higher cost replacement of unavailable capacity or the out-of-merit running of plant for inflexibility considerations. The category of GOC is limited to those costs incurred due to any constraint associated with a generation outage or derating. The category of GLC is limited to those costs incurred due to the inability of generating plant to operate in an ideally flexible manner under intact plant conditions. Conversion Inefficiency Costs represent the additional fuel that has to be burnt due to plant operating at less than that demonstrated conversion efficiency which can be achieved when all equipment is available and is in the best practical working order.

Environmental Restriction Costs occur due to the non-optimum operation of plant in order to accommodate mandatory environmental requirements. This includes such items as the management of air-quality which necessitates the uneconomic loading or shutdown of in-merit generating plant, the adjustment of the operation of hydraulic generation facilities to accommodate legislated requirements for water flows, etc. Hydraulic Utilization Inefficiency Costs represent the additional fuel costs incurred as a result of the inability to operate the hydraulic system in an ideally flexible manner. This includes such items as the voluntary adjustment of hydraulic generation or environmental consideration.

Generation Scheduling Inefficiency Costs represent the additional fuel costs incurred by the non-optimum use of generation resources for any reason not assigned to another classification. This includes such items as non-optimum dispatch, overcommitment, undercommitment, reserve capacity, the voluntary adjustment of thermal generation for environmental considerations, etc.

#### 4.1.2 SEP Netherlands

In 1986, the Bulk Electricity System in the Netherlands was restructured from 11 producing companies coordinated by SEP, to an active power pool structure along with SEP. The generation and bulk transmission was organizationally separated from distribution. In 1987 the new structure was put in operation, now with five producing companies delivering to SEP.

In order to monitor economic performance of the BES an economic performance model has been established. The model differentiates between the production process and the product, the delivered energy in MWh.

#### Economy and Quality of the Production Process

The cost model of the production process is as follows:

Total Variable Production Cost = "Ideal + Costs Due to Non-Ideal Conditions and Faults" ("non-ideal costs")

"Ideal Costs" are those costs that arise when under normal conditions, all costs that can be avoided are avoided. "Non-ideal costs" are separated into costs that cannot be influenced without additional long term investments (eg, network restrictions, environmental constraints, etc) and costs that can be influenced by control measures.

Costs that can be influenced are the so called "Quality Costs". Quality Costs consist of costs for prevention, inspection and faults, malfunction, non-optimum operation, etc.

The aim is to define the key factors that determine the ideal production costs, the costs due to restrictions and the Quality Cost.

At present the approach to monitor these cost components is the following.

The ideal costs are defined as the production costs being calculated by an optimization program without any technical restriction that could be influenced (by investments or by other measures). Ideal costs can be compared with the calculated cost in the medium term planning. The medium term planning figures could be considered as a sort of "performance standard." The quality performance standard for the medium term planning itself is a certain loss of load probability.

The costs that can not be influenced without investments are calculated by adding the restrictions to the optimization calculation. The effect on cost increase can be studied per restriction.

The remainder of the actual production costs is considered to be quality cost.

#### Economy and Quality of the Product

The economy of the production process completely determines the cost of the product. The quality of the product (voltage, frequency, continuity of supply) is determined by the quality of the process. In the case of SEP no precise quality standards to the delivered kWh at the delivery points of the BES are defined. The quality is mainly a result of the high quality standards of the BES components, the postulated loss of load probability at medium term planning and the N-1 security criterium, which is applied when planning and operating the system. As a matter of fact quality of supply in the interconnected system is in most cases determined by network restrictions and unreliability of network elements. The actual quality in terms of continuity is probably higher than required if such a precise requirement would exist.

#### 4.1.3 Electricity Generating Authority of Thailand (EGAT)

EGAT is now in the early stage of setting up a measurement system to assess the economic performance of the power system operation. A "relative" approach, by which certain aspects of the economic performance are compared against some references, has been used. The measurement system is as follows:

- (1) Assessment of the economic performance of the power plants.
- (2) Assessment of the economic performance of the production cost.

The first approach assesses the fuel conversion efficiency of each power plant, under the name of STEP (Station Thermal Efficiency Performance) factor scheme. The target thermal efficiency is assessed from the actual load imposed on the plant during each month. This actual load and other operating conditions are used to calculate a number of parameters of the generator as if it is in the "as new" condition, and the values of these parameters combine to give the target thermal efficiency. Finally, this target efficiency is compared with the actual thermal efficiency which is obtained from the actual measurements. The scheme was first introduced in 1986. The STEP factors of different plants can be compared and the additional loss can be categorized and further analyzed for improvements. These values of thermal efficiency can also be converted into costs when desired. The second approach exploits the available facilities of the system control centre. In this approach the computer determines the generation schedules for power plants (by the Hydro-Thermal Optimization Program) and the allocation of generation among the committed units (by the Economic Dispatch Program) in the most economical manner. The cost resulting from such optimal scheduling is a theoretical, ideal cost, assuming no operational constraints whatsoever. The actual production cost is computed and compared to this ideal cost. The difference is an additional cost due to all kinds of constraints, such as generation outage, transmission line outage, security constraint, voltage constraint, water constraint, fuel supply limit, etc.

#### 4.2 Utility-Specific Measurements

Responses containing utility-specific measurements were received from 21 utilities in 15 countries.

The performance measurements in the responses were compiled into listings under the following headings:

- (1) Generation Cost Measures: Currency Based.
- (2) Generation Cost Measures: Indirect.
- (3) Transmission Cost Measures.
- (4) Operational Planning, Scheduling, and Dispatching Cost Measures.

Utilities reported a great variety of measures used to assess cost performance. Some are obviously directly related to cost although not measured in currency terms. For others the relationship is less obvious.

For example, Reliability measures such as forced outage rate have a great bearing on cost when applied to lower-cost base-loaded generation, but are less applicable on higher-cost units. The starting reliability of peaking units is likewise an important economic consideration on some systems, but not on others. The Working Group did not attempt to pass judgment on the validity of these measures as cost performance measures. If included in the response by a utility user, then it was deemed a valid cost performance measure.

Also, it should be noted that the Working Group did not attempt to establish cost performance standards. Terminology differences were eliminated, but only to avoid the repetition of measures that were similar or the same except for language. Extensive use was made of acronyms, but only so that the material could be presented in an easy-to-read format.

The listings found in Appendix A, then, are a compilation of the information submitted in a format that should make it useful to utilities wishing to examine the cost performance measures used by others in establishment or modification of their own systems.

#### 5.0 CONCLUSION

As a result of the work undertaken in the period 1983-1988 on operational performance measurements for Bulk Electricity Systems, the electric utility industry now has available to it:

- A standard performance measurement system for Security - the System Disturbance Performance Measurement System.
- A System Disturbance performance data base of respectable size, containing 1 333 utility-years of data collected from 168 utilities worldwide.
- Convenient means of comparison so that a utility can readily compare its performance to the average performance of other utilities, or to their ranges of performance, and relative to the entire set or to subsets with specified characteristics.
- A standard performance measurement system for the continuity aspect of Quality - the BES Delivery Point Performance Measurement System.
- A Delivery Point performance data base of respectable size, containing one year's performance data for 19 586 Delivery Points in 72 utilities worldwide.
- Convenient means of comparison so that a utility can readily compare its performance to the average performance of other utilities, or to the range of their performances, and relative to the entire set or to the subsets supplying radial or meshed distribution.
- A standard performance measurement system for Frequency Deviation Events, together with a performance data base, which though small, ie, 12 utilities, indicates the wide range of performance attributable to different system circumstances.

- A listing of operational cost performance measurements in use in utilities in 15 countries worldwide, and a description of three comprehensive cost performance measurement systems.

By no means, however, does this work establish a complete base for those who wish to manage performance directly relative to operational objectives. Objective standards must be set and means such as analytical models must be developed to assess how changes in utility practice will result in changes to performance.

The utility of the data bases will be enhanced if they are expanded so that there is broader coverage, and so that assessments can be made of changes over time.

To this end, utilities establishing or modifying their own operational performance data bases are encouraged to do so in a fashion that is at least compatible with those described herein.

## 6.0 ACKNOWLEDGEMENTS

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 Ireland: P. Haren  
 Italy: E. Mariani  
 Norway: A.T. Holen  
 Spain: A.M. Diu  
 Sweden: R. Kearsley

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- [7] Winter, W.H., LeReverend, B.K. "Voltage, Frequency and Delivery Point Performance of Bulk Electricity Systems" (CIGRE 39.05)

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## APPENDIX A

### GENERATION COST MEASURES: CURRENCY BASED

- (1) Basic Unit Energy Cost (BUEC) or Fueling Unit Energy Cost (FUEC)

Cost of fuel per unit of energy production. Fueling cost is typically the cost of fuel burned to generate electricity (including water use fees for hydraulic), excluding the interest costs on fuel inventory.

- (2) OM&A Unit Energy Cost (OM&A UEC)

Is typically the cost of operation, maintenance, and administration per unit of energy production.

- (3) Production Unit Energy Cost (PUEC)

Is the sum of BUEC and OM&A UEC.

- (4) Total Unit Energy Cost (TUEC)

Is the sum of PUEC and interest and depreciation per unit of energy production.

- (5) OM&A Unit Capacity Cost (OM&A UCC)

Is typically the cost of operation, maintenance per unit of capacity produced.

- (6) Total Unit Capacity Cost (TUC)

Is typically the sum of OM&A UCC and interest and depreciation per unit of capacity produced.

- (7) OM&A Unit Capacity Cost Reliable [OMUCC(r)]

$$OMUCC(r) = \frac{OM\&A}{MCR (Net) \times CbF (Gross)}$$

where:

MCR is the maximum continuous rating of the unit.

CbF, the equipment capability factor, is equal to:

$$1 - \frac{\text{Outage Time}}{\text{Number of Hours in Period}}$$

(8) Capital Unit Capacity Cost Reliable [CUCC(r)]

$$CUCC(r) = \frac{\text{Interest and Depreciation}}{\text{MCR (Net) x CBF (Gross)}}$$

(9) Total Unit Capacity Cost Reliable [TUCC(r)]

TUCC(r) is the sum of OMUCC(r) and CUCC(r).

Many of the foregoing measures are used for a variety of purposes, ie, to measure a utility, a type of generation (eg, nuclear), a generating station or individual generating units. Also, they are employed for a variety of time frames, ie, monthly, annually, lifetime.

(10) Conversion Inefficiency Cost

Calculation of the additional fueling cost incurred as the result of operation of generation at less than demonstrated conversion efficiency when all equipment is available and in the best practical working order.

(11) Cost of Operational Limitations

Calculation of the additional fueling cost incurred as the result of inability to operate generation in an ideally flexible manner under intact plant conditions. Included are minimum run times, limitations on loading and unloading rates, minimum load limits.

(12) Cost of Hydraulic Spillage

Calculation of the increased fueling costs incurred as the result of:

- (a) Equipment out of service.
- (b) Storage limitations.

(13) Cost of Operating Hydraulic Beyond Best Efficiency

Comparison of the value received for energy generated from hydraulic unit operation beyond best efficiency to the calculated future worth had the water remained in storage.

GENERATION COST MEASURES: INDIRECT

(1) Forced Outage Rate (FOR)

$$FOR = \frac{\text{Forced Outage Time}}{\text{Forced Outage Time \& Operating Time}}$$

(2) Derating Adjusted - Forced Outage Rate (DAFOR)

A requirement of FOR.

$$DAFOR = \frac{\text{Forced Outage Time}}{\text{Equivalent Forced Outage Time and Operating Time}}$$

Where the Equivalent Forced Outage Time includes the effect of deratings.

(3) Derating Adjusted Utilization Forced Outage Probability (DAUFOP)

A special version of DAFOR used generally for higher cost generating units which adjusts DAFOR to reflect the fact that these units may not be

needed by the system when on forced outage or derated.

(4) Capability Factor (CBF)

The ratio of the energy that a generating source could have delivered over a period of time (with due regard to outages and deratings) if there were no constraints external to the source, to the energy which would be delivered if the source operated continuously at Maximum Continuous Rating over the period.

(5) Capacity Available When Needed (CAWN)

- (a) Measures the ability of a generation source to supply Maximum Continuous Rating when needed.

$$CAWN = \frac{\text{Hours When Needed} - \text{Hours Unavailable}}{\text{Hours When Needed}} \times 100$$

- (b) Two versions are utilized CAWN (a) and CAWN (p) which, respectively compute CAWN annual and for the peak month or months of the year.
- (c) It is assumed that a unit is not needed when it is available, but not in service, and when it has been granted a planned outage or scheduled derating.

(6) Start Rate (SR)

$$SR = \frac{\text{Start Successes}}{\text{Start Attempts}} \times 100$$

- (a) A start success is a start attempt that results in a generating unit being synchronized within 15 minutes of its scheduled starting time, and remaining synchronized for at least 30 minutes unless shut down by a system dispatch order.
- (b) A start attempt has occurred when a boiler purge has been initiated in response to a system dispatch order to start.

(7) Delivery Rate

$$DR = \frac{\text{MWh (Net) Generated} \times 100}{\text{MWh (Net) Generated} + (\text{Forced Derated Adjusted Hours} \times (\text{Average Station's Running Load}))}$$

Measures how well a unit was able to meet the energy needs of the system whilst operating. It assumes that a unit would be expected to operate at the same average load as all other units at that station during the time period in question.

(8) Peaking Delivery Rate (PDR)

$$PDR = \frac{\text{MW.h(net) generated above MCR}}{(\text{Operating Hours Above MCR}) \times (\text{PK Cap} - \text{MCR})} = \frac{\text{Sum of Actual Peak MWh Produced}}{\text{Sum of Potential MW.h for the Event}}$$

Where:

PK Cap is Peak Capacity and MCR is Maximum Continuous Rating.

(9) Sudden Outage Frequency (SOF)

(a) A sudden outage is an unscheduled outage initiated from within the generating unit boundary while the unit is loaded above 25% of its maximum electrical output and whose starting time cannot be postponed beyond 10 minutes following the occurrence of its initiating cause.

(b) The SOF for unit groupings is calculated using the following expression:

$$SOF = \frac{\text{Total Number of Sudden Outages}}{1\ 000 \text{ Operating Hours}} = \frac{\sum_{i=1}^n \text{Number of Sudden Outages for Unit } i}{\sum_{i=1}^n \text{Operating Time of unit } i} \times 1\ 000$$

Where:

n = Number of units in the group

(c) SOF is expressed in terms of events per 1 000 operating hours

(10) Sudden Reduction Frequency (SRF)

$$SRF = \frac{\text{Number of Sudden Reductions}}{1\ 000 \text{ Operating Hours}}$$

(a) A Sudden Reduction is an unscheduled load reduction to station service load initiated from within the generating unit boundary while the unit is loaded above 25% of its maximum electrical output, and whose starting time cannot be postponed beyond 10 minutes following the occurrence of its initiating cause. The unit remains synchronized to the system following the load reduction.

(b) The quantity is given by the same mathematical relationships as SOF when the number of Sudden Reductions is substituted for the number of Sudden Outages.

(11) Stress Frequency (SF)

SF = Sudden Outage Frequency + Sudden Reduction Frequency

(12) Survival Rate (SR)

$$SR = \frac{TNS - ISE}{TNS} \times 100$$

Where:

TNS = Total Number of Survivals of System

TNS = Total Number of Systems

ISE = Imposed Stress Events

(a) A stress event is either:

- a separation of the generating unit from the BES initiated from outside the generating station boundary

- a disturbance on the BES which may require a full or partial load rejection. This may be caused by:

• unit operation above 60.2 Hz or below 59.8 Hz

• operating with system voltage deviations of more than ±10%

• local system faults, eg, lightning

(b) The unit itself may be required to separate from the system, depending on the severity of the disturbance, to protect itself. A unit suffers a non-survival of a stress event if:

- The unit:

• should have remained connected to the system delivering energy but did not.

• should have separated from the system but did not.

- The unit separated (automatically or manually) from the system for protection and was not available for reloading within 20 minutes of the stress event (or when required if reloading was delayed at the request of system dispatch).

- The unit separated from the system due to a generation rejection scheme and was not available for reloading within 20 minutes of the stress event (or when required if reloading was delayed at the request of system dispatch).

(13) Start-Up Performance Rate (SPR)

$$SPR = \frac{\sum \frac{R}{X}}{n} \times 100$$

Where:

X = Actual Heat Input

R = Reference Heat Input

n = Number of Starts

$$\frac{\text{Net Reference Heat Rate}}{\text{Net Actual Heat Rate}} \times 100$$

The average load is determined for the time period the unit is running between minimum and maximum load (how often, ie, every 12 hours, 24 hours, etc). From this, the net actual heat rate is calculated. Using the same load, the net reference heat rate is determined (this is based on acceptance test data).

This is a measure of the actual heat rate for a unit (or station) while generating above minimum load compared to a reference heat rate based on acceptance tests (or, in some instances, based on the current state of the unit as determined internally or by an independent inspection company).

(14) Thermal Efficiency Performance Ratio (TEPR)

The ratio of the actual heat rate for a generating unit when generating above minimum load to a reference heat rate based on acceptance tests (or, in some instances, based on the current state of the unit as determined internally or by an independent inspection company).

(15) Coal Usage

The extent to which thermal plant measured coal usage matches a computed value of the coal that would have produced the same output at best efficiency for the actual output levels.

(16) Staffing

A variety of indices are employed, ie, staff per generating unit, staff per MWh, staff per MW.

(17) Hydraulic Storage Utilization Index (HSI)

$$\text{HSI} = \frac{\text{Avoidable Energy Remaining in Storage at the Commencement of Freshet}}{\text{Total Energy Storage Capability}}$$

(18) Hydraulic Unit Loading

- (a) The extent to which identical generating units at a hydraulic generating stations are loaded equally and at the desired output level.
- (b) The loss of energy caused by deviation from the best efficiency point of hydraulic generating units.

(19) Hydraulic Conversion Effectiveness

Comparison of actual efficiency with efficiency established previously by test. This detects deterioration in efficiency through time.

(20) Maximum and Minimum Power

Periodic tests are carried out to verify the maximum and minimum power capability of power plants.

(21) Ramp Rates

Periodic tests are carried out to verify the ramp rates of power plants.

TRANSMISSION COST MEASURES

Relatively few transmission operational cost performance measurements were reported.

(1) OM&A Transmission Unit Energy Delivered Cost

Expressed in currency units/KWh.

(2) OM&A Transmission Unit Capacity Unit Cost

Expressed in

- (a) currency units/circuit km, or
- (b) kilovolt.ampere.km.

(3) OM&A Transmission Station Facilities Unit Cost

Expressed in currency units/circuit termination.

(4) Transmission Outage Cost Monitoring

The cost of outages to transmission system equipment are monitored and comparisons made between planned and actual costs. Outages are categorized as construction or maintenance, and planned or forced.

(5) Intact Transmission System Limit Cost

The cost of fueling increases caused by transmission system operating limits. The system is normalized to an intact system, ie, to a system with all transmission in service and capable of operating at approved ratings so as to differentiate between outage costs and system limits costs.

(6) Usage Duration of Transmission System Elements

The usage duration of UHV transmission lines and transformers.

(7) Utilization of Major Transmission System Elements

The percentage of actual transfers relative to rated transfer capability.

OPERATIONAL PLANNING, SCHEDULING AND DISPATCHING COST MEASURES

Utilities also reported a great variety of measures used to assess performance in the areas of operational planning, scheduling, and dispatching. Most are in non-currency terms:

(1) Thermal Generation Scheduling Inefficiency Cost

(a) Thermal Generation Scheduling Inefficiency Costs represent those additional fuel costs which were incurred as a result of non-optimum use of thermal plant.

(b) Examples are costs associated with the following:

- Operating reserve requirements.
- Retaining thermal units in service overnight in order to avoid startup failures the next day.
- Plant heating requirements.
- Co-production limitation (plant would not be required but must be operated to provide heat to a town). The town pays for the heat but not the additional cost of keeping the plant on-line.

(2) A Posteriori Production Costing

Comparison of the daily, weekly or monthly actual primary fuel cost against a simplified ideal minimum primary fuel cost.

(3) Generator Output Off Optimum

The cumulative deviation of individual generator outputs from the optimal schedules are measured.

(4) Dispatch Accuracy Monitoring

Comparison of forecast and actual values of one or more of:

- daily maximum loading, conventional thermal
- daily minimum loading, conventional thermal
- daily minimum loading of individual midmerit generating units
- daily energy, conventional thermal
- daily maximum loading, gas turbine generation
- daily minimum loading, gas turbine generation
- daily maximum loading, hydraulic generation
- daily minimum loading, hydraulic generation
- daily energy, hydraulic generation
- daily maximum interchange with other utilities
- daily minimum interchange with other utilities
- daily energy, interchange with other utilities
- daily pumped storage loading
- daily pumped storage energy
- daily thermal spinning reserve at time of peak
- daily hydraulic spinning reserve at time of peak
- daily thermal unit availability
- daily hydraulic factors, eg, streamflows
- weekend hydraulic reservoir levels

(5) Operational Planning Accuracy Monitoring

Comparison of forecast and actual values of one or more of:

- monthly conventional thermal energy production
- monthly hydraulic energy production
- monthly energy, interchange with other utilities
- "utilization hours" of conventional thermal (energy generated divided by rated power)
- month end hydraulic reservoir levels
- annual conventional thermal energy production
- annual hydraulic energy production
- annual energy, interchange with other utilities
- annual kcal/kWh for each thermal unit and for classes
- annual availability index for each thermal unit and for classes
- dates of hydraulic reservoir maximum and minimum levels

(6) Number of Start-Ups

Monitoring and comparison of number of start-ups of generating units versus planned start-ups.

(7) Condensing Power Production

Monitoring of condensing power production forecast accuracy.

(8) Night-Time Generating Unit Minimum Load Checks

Check on night-time minimum loads achieved by the midmerit generating units (to maintain operating flexibility and high load factors on base load generating units).

(9) Cold Plant Changes

Monitoring of changes in use of cold plant-returns are made of cold plant brought into use and vice versa.

(10) Two-Shift Capability - Benefit

During the night minimum period some conventional fossil-fired plants are often not required for generation purposes and substantial fuel costs savings can result if such plants are shut down. The savings are measured.

(11) Two-Shift Capability - Operations

The number of thermal generating unit two-shift operations effected versus the number that should have been effected to achieve minimum cost.

(12) Gas Turbine Operation

Monitoring of the number of operations of the most expensive generation type with associated daily cost, amount of energy produced, and reason for operation.

(13) Load Management

Actual results of load management operations (demand reductions) along with cumulative hours are monitored and compared with planned figures.

(14) Generator Outages

Delayed or shorter scheduled and non-scheduled outages are monitored on an individual generator basis.

(15) Accuracy of Operational Load Forecasts

Comparison of forecast and actual values of one or more of:

- daily/weekly peak hour load
- daily minimum hour load
- daily energy
- weekly energy
- daily/weekly weather-corrected peak hour load
- daily/weekly weather-corrected energy

(16) Inadvertent Energy

Monitoring of inadvertent energy flows between interconnected utilities.

(17) Savings Through Use of Voltage Reduction in Operating Reserve

The saving in fueling costs is calculated to assess the impact of a change in operating policy.

(18) Stretch Capability

Stretch (or peaking) capability of generation plant is the capability to generate at output levels in excess of maximum continuous rating for extended periods of time. As a general statement, it may be said that stretch is used to protect the primary demand or to provide a secondary sales capability to any utility provided that a certain minimum level of sales profit is achieved, and to save running costs of having to bring another plant in operation.

The benefit of stretch is the savings in fuel cost. To bring the benefits of stretch to a common base for each generating station (and, in this instance to allow some year-to-year comparison), an index of "Benefit/Unit Hour of Operation" is employed.

(19) Generator Outage Scheduling Cost Per MW Day

The Generator Outage Scheduling Cost (GOSC) Per MW Day provides a measure of the average cost of scheduled outages; it is restricted to outages of nuclear and fossil-fired plants. The definitions of Generator Outage Scheduling per MW Day is given below.

$$GOSC = \frac{TCSO}{TSO}$$

Where:

TCSO = Total Additional Fuel Cost of Scheduled Outages

TSO = Total MW Days of Scheduled Outages

(20) Tie Line Restoration Index (TLRI)

$$TLRI = \frac{A}{B}$$

Where:

A = Number of times tie line flows are restored to schedule in 10 minutes.

B = Number of generation losses greater than "x" MW and not exceeding first contingency loss.

The required amount of synchronized operating reserve varies with performance relative to this index.

(21) Ten Minute Reserve Index (TMRI)

$$TMRI = \frac{NH}{ND} \times 100$$

Where:

NH = Number of daily peak hours in which the 10 minute reserve requirement was exceeded.

ND = Number of days in reporting period.

(22) Citizenship Events

(a) The number and cost of events where departures from economic hydraulic operation were undertaken in response to requests to improve conditions for specific situations, eg, control of flows and currents to assist recreational events.

(b) The number and cost of events where departures from economic operation were undertaken to improve air quality before levels attained legal limits.

(23) Market Penetration for Off-System Opportunity Sales Index (MPSI)

$$MPSI = \frac{\text{Actual Sales Volume}}{\text{Total sales into market area}} \times 100$$

(24) Surplus Generation Utilization Index (SGUI)

$$SGUI = \frac{ASV}{DSGV} \times 100$$

Where:

ASV = Actual Sales Volume

DSGV = Deliverable Surplus Generation Volume

(25) Opportunity Purchase Savings Optimization Index (PSOI)

$$PSOI = \frac{\text{Actual Purchase Savings}}{\text{Optimal Purchase Savings}} \times 100$$

(26) Defense Plan or Control Aid Net Benefit

(a) Calculation of the cost benefits attributable to the installation of schemes such as generation rejection and load and generation rejection schemes to increase allowable transmission loading.

(b) The benefit is the sum of the fuel savings and increased opportunity sales and purchase transactions benefits.

(27) Outage Coordination Net Benefits

(a) The calculated benefits attributable to the development of the coordinated transmission and generation outage schedules.

(b) The benefit is the sum of the fuel savings and increased transaction benefits minus any additional site costs for the outage work.

(28) A Posteriori Cold Reserve Time Monitoring

The calculation of the frequency of unnecessary shutdowns of large thermal generating units (where start-up fuel is expensive).

(29) Transmission Element Outages

Comparisons are made of the actual planned and unplanned outages of transmission elements to standards.