International Journal on Emerging Technologies **2**(2): 134-140(2011)
ISSN No. (Print) : 0975-8364
ISSN No. (Online) : 2249-3255

Benchmarking of Data for Power Quality Evaluation

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(Received 17 October, 2011, Accepted 14 November, 2011)

ABSTRACT : EPRI has been studying power quality (PQ) problems and solutions for over 15 years. This paper presents many new and innovative approaches to PQ monitoring, analysis, and planning that have been developed. This paper will serve as a useful reference for identifying suitable indices for benchmarking the quality of service and analytical methods for extending the capabilities of PQ monitoring instrumentation. In the overall context of a PQ program, benchmarking is an essential ingredient. Because of sensitive customer loads, there is a need to define the quality of electricity provided in a common and succinct manner that can be evaluated by the electricity supplier as well as by consumers or equipment suppliers. This paper describes recent developments in methods for benchmarking the performance of electricity supply.

Keywords: Power Quality, Benchmarking, Indices, PQ monitoring, service quality.

I. INTRODUCTION

Power quality benchmarking is an important aspect in the overall structure of a power quality program. The benchmarking process begins with defining the metrics to be used for benchmarking and evaluating service quality. The EPRI Reliability Benchmarking Methodology project (EPRI Reliability Benchmarking Methodology, EPRI TR-107938, EPRI, Palo Alto, California) defined a set of PQ indices that serve as metrics for quantifying quality of service. These indices are calculated from data measured on the system by specialized instrumentation. Many utilities around the world have implemented permanent PQ monitoring systems for benchmarking power quality. However, there are still considerably large gaps in coverage of the power system with PQ monitors. As part of the EPRI Reliability Benchmarking Methodology project, investigators explored the idea of estimating the voltages at locations without monitors given the data at only one monitor or a few monitors. This resulted in the development of the concept of the EPRI Power Quality State Estimator (PQSE), which uses feeder models and recorded data to estimate what would have been recorded on the customer side of the service transformer. A comprehensive set of power quality indices was defined for the Electric Power Research Institute (EPRI) Reliability Benchmarking Methodology (RBM) project1 to serve as metrics for quantifying quality of service. The power quality indices are used to evaluate compatibility between the voltage as delivered by the electric utility and the sensitivity of the end user's equipment.

II. BENCHMARKING PROCESS

Electric utilities throughout the world are embracing the concept of benchmarking service quality. Utilities realize that they must understand the levels of service quality provided throughout their distribution systems and determine if the levels provided are appropriate. This is certainly becoming more prevalent as more utilities contract with specific customers to provide a specified quality of service over some period of time. The typical steps in the power quality benchmarking process are

1. *Select benchmarking metrics:* The EPRI RBM project defined several performance indices for evaluating the electric service quality.4 A select group are described here in more detail.

2. *Collect power quality data:* This involves the placement of power quality monitors on the system and characterization of the performance of the system. A variety of instruments and monitoring systems have been recently developed to assist with this labor-intensive process.

3. *Select the benchmark:* This could be based on past performance, a standard adopted by similar utilities, or a standard established by a professional or standards organization such as the IEEE, IEC, ANSI, or NEMA.

4. *Determine target performance levels:* These are targets that are appropriate and economically feasible. Target levels may be limited to specific customers or customer groups and may exceed the benchmark values

Finally, after the appropriate data have been acquired, the service provider must determine what levels of quality are appropriate and economically feasible. Increasingly, utilities are making these decisions in conjunction with individual customers or regulatory agencies.

Most utilities have been benchmarking reliability for several decades. In the context of this book, reliability deals with sustained interruptions. IEEE Standard 1366-1998 was established to define the benchmarking metrics for this area of power quality. 5 The metrics are defined in terms of system average or customer average indices regarding such things as the number of interruptions and the duration of interruption (SAIDI, SAIFI, etc.).

In 1989, the EPRI initiated the EPRI Distribution Power Quality (DPQ) Project, RP 3098-1, to collect power quality data for distribution systems across the United States. Monitors were placed at nearly 300 locations on 100 distribution feeders, and data were collected for 27 months. The DPQ database contains over 30 gigabytes of power quality data and has served as the basis for standards efforts and many studies. 1,6 The results were made available to EPRI member utilities in 1996.

The indices were patterned after the traditional reliability indices with which utility engineers had already become comfortable.

Indices were defined for

1. Short-duration rms voltage variations. These are voltage sags, swells, and interruptions of less than 1 minute.
2. Harmonic distortion.
3. Transient overvoltages. This category is largely capacitor-switching transients, but could also include lightning-induced transients.
4. Steady-state voltage variations such as voltage regulation and phase balance.

III. POWER QUALITY INDICES

A. RMS Voltage Variation Indices

For many years, the only indices defined to quantify rms variation service quality were the sustained interruption indices (SAIFI, CAIDI,etc.). Sustained interruptions are in fact only one type of rms variation. IEEE Standard 1159-19957 defines a sustained interruption as a reduction in the rms voltage to less than 10 percent of nominal voltage for longer than 1 min

(*i*) *Characterizing RMS Variation Events*

IEEE Standard 1159-19957 provides a common terminology that can be used to discuss and assess rms voltage variations, defining magnitude ranges for sags, swells, and interruptions. The standard suggests that the terms sag, swell, and interruption be preceded by a modifier describing the duration of the event (instantaneous, momentary, temporary, or sustained).

RMS variations are classified by the magnitude and duration of the disturbances. Therefore, before rms variation indices can be calculated, magnitude and duration characteristics must be extracted from the raw waveform data recorded for each event. Characterization is a term used to describe the process of extracting from a measurement useful pieces of information which describe the event so that not every detail of the event has to be retained. Characterization of rms variations can be very complicated. It is structured into three levels, each of which is identified as a type of event as follows:

(*a*) Phase or component event

(*b*) Measurement event

(*c*) Aggregate event.

(*ii*) *RMS variation performance indices*

The rms variation indices are designed to assess the service quality for a specified circuit area. The indices may be scaled to systems of different sizes. They may be applied to measurements recorded across a utility's entire distribution system resulting in SAIFI-like system averages, or the indices may be applied to a single feeder or a single customer PCC. There are many properties of rms variations that could be useful to quantify properties such as the frequency of occurrence, the duration of disturbances, and the number of phases involved. Many rms variation indices were defined in the EPRI RBM project to address these various issues. Space does not permit a description of all of these, so we will concentrate on one index that has, perhaps, become the most popular. The papers and reports included in the references contain details on others.

System average RMS (variation) frequency indexVoltage ($SARFI_x$).

$SARFI_x$ represents the average number of specified rms variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than x for sags or a magnitude greater than x for swells:

$$SARFI_x = \frac{\Sigma N_i}{N_T}$$

where x = rms voltage threshold; possible values are 140, 120, 110, 90, 80, 70, 50, and 10

N_i = number of customers experiencing short-duration voltage deviations with magnitudes above X percent for $X > 100$ or below X percent for $X < 100$ due to measurement event i.

N_T = total number of customers served from section of system to be assessed.

An increasing popular use of SARFI is to define the threshold as a curve. For example, SARFIITIC would represent the frequency of rms variation events outside the ITI curve voltage tolerance envelope.

Three such curve indices are commonly computed:

- SARFICBEMA
- SARFIITIC
- SARFISEMI

There are three additional indices that are subsets of SARFIx. These indices assess variations of a specific IEEE Standard 1159 duration category:

(*a*) System Instantaneous Average RMS (Variation) Frequency Index ($SIARFI_x$).

(*b*) System Momentary Average RMS (Variation) Frequency Index ($SMARFI_x$).

(*c*) System Temporary Average RMS (Variation) Frequency Index ($STARFI_x$).

(*iii*) *Index Computation*

This example is based on actual data recorded on one of the feeders monitored during the EPRI DPQ project. This illustrates some of the practical issues involved in computing the indices

Table 1: SARFI Statics from the EPRI DPQ Project.

	$SARFI_{90}$	$SARFI_{80}$	$SARFI_{70}$	$SARFI_{50}$	$SARFI_{10}$	$SARFI_{CBEMA}$	$SARFI_{ITIC}$	$SARFI_{SEMI}$
Minimum	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CP50†	11.887	5.594	0.000	0.000	0.000	5.316	2.791	2.362
CP50†	43.987	22.813	12.126	5.165	1.125	25.465	18.765	13.619
MEAN	56.308	28.729	18.422	8.926	3.694	33.293	25.390	18.535
CP95†	135.185	66.260	51.000	27.037	13.519	71.413	51.500	38.238
Maximum	207.644	103.405	70.535	56.311	35.689	149.488	140.768	140.768

(*iv*) *Utility applications*

Utilities are using the discussed rms variation indices to improve their systems. One productive use of the indices is to compute the separate indices for individual substations as well as the system index for several substations. The individual substation values are then compared to the system value.

Table 2: Example RMS Variation Index Values Calculated Based on 1 Year of Actual Monitored Data.

X	$SARFI_x$	$SIARFI_x$	$SMARFI_x$	$STARFI_x$
140	0.0	0.0	0.0	0.0
120	0.0	0.0	0.0	0.0
110	0.5	0.5	0.0	0.0
90	27.5	22.7	4.3	0.5
80	13.6	8.8	4.3	0.5
70	7.3	2.5	4.3	0.5
50	4.8	0.5	3.8	0.5
10	4.3	Undefined	3.8	3.5

B. Harmonics Indices

Power electronic devices offer electrical efficiencies and flexibility but present a double-edged coordination problem with harmonics. Not only do they produce harmonics, but they also are typically more sensitive to the resulting distortion than more traditional electromechanical load devices. End users expecting an improved level of service may actually experience more problems. The fundamental quantity used to form the indices is the THD of the voltage. The THD may be found using Eqn. (1).

$$V_{THD} = \frac{\sqrt{\sum_{h=2}^{\infty} V_h^{\,2}}}{V_1} \qquad \dots (1)$$

This presents a problem in characterizing the harmonic distortion of a three-phase measurement which has varying distortion levels on each phase. There are two possible methods:

1. Consider each phase to be a separate measurement. The potential problem with this method is that a count of how often distortion levels exceed a specified level could be 3 times too large.
2. Average the distortion levels on the three phases. Each three-phase steady-state measurement contributes a single distortion level to the samples. A possible drawback is that a high distortion level on one phase is obscured if the other two phases exhibit low distortion levels.

(*i*) *System total harmonic distortion CP95* (*STHD95*).

STHD95 represents the CP95 value of a weighted distribution of the individual circuit segment CP95 values for voltage THD . STHD95 is defined by Eqs. (2) and (3):

$$\frac{\sum_{-\infty}^{STHD95} f_t(CP95_s)\times L_s}{\sum_{-\infty}^{\infty} f_t(CP95_s)\times L_s} = 0.95 \qquad \dots (2)$$

$$\frac{\sum_{-\infty}^{CP95_s} f_s(x_i)}{\sum_{-\infty}^{\infty} f_s(x_i)} = 0.95 \qquad \text{... (3)}$$

where,

s =circuit segment number

i = steady-state THD measurement number

L_s = connected kVA served from circuit segment s

$f_s(x_i)$ = probability distribution function comprised of sampled. THD values for circuit segment *s*.

$CP95_s$ = 95th percentile cumulative probability value; it is a statistical quantity representing the value of THD which is larger than exactly 95 percent of the samples comprising the THD distribution for segment *s*.

$f_t(CP95_s)$ = probability distribution function comprised of the individual circuit segment THD CP95 values.

(*ii*) *System average total harmonic distortion* (*SATHD*).

SATHD is based on the mean value of the distribution of voltage THD measurements recorded for each circuit segment rather than the CP95 value. SATHD represents the weighted average voltage THD experienced over the monitoring period normalized by the total connected kVA served from the assessed system. SATHD is defined by Eqs. (4) and (5):

$$SATHD = \frac{\sum_{s=1}^{k} L_s \times MEANTHD_s}{L_T} \qquad \text{... (4)}$$

$$MEANTHD_s = \frac{\sum_{t=1}^{N_{MW}} THD_t}{N_{MW}} \qquad \text{... (5)}$$

where,

s =circuit segment number

k = total number of circuit segments in the system being assessed

L_s = connected kVA served from circuit segment s

L_T = total connected kVA served from the system being assessed

i = steady-state measurement number

THD_i = voltage total harmonic distortion calculated for measurement window i

N_{MW} = total number of steady-state measurement windows collected for a given circuit segment over the duration of the monitoring period

$MEANTHD_s$ = statistical mean of the THD values obtained from each of the steady-state measurement windows for circuit segment *s*.

(*iii*) *System average excessive total harmonic distortion ratio index THD level* ($SAETHDRI_{THD}$)

The system average is then computed by weighting each segment ratio by the load served from that segment. SAETHDRITHD is defined by

$$SAETHDRI_{THD} = \frac{\sum_{s=1}^{k} L_s \times \left(\frac{N_{THD_s}}{N_{MW_s}} \right)}{L_T} \qquad \text{... (6)}$$

where,

s = circuit segment number

k = total number of circuit segments in the system being assessed

L_s = connected kVA served from circuit segment s

L_T = total connected kVA served from the system being assessed

i = steady-state measurement number

THD = THD threshold specified for calculation of this index

N_{THD_s} = number of steady-state measurements that exhibit a THD value for segment s which exceeds the specified THD threshold value

N_{MW_s} = total number of steady-state measurements recorded for segment s over the assessment period.

IV. POWER QUALITY CONTRACTS

The deregulation of the electric power utilities in many areas further complicates things. As Kennedy 12 points out regarding future trends, there now might be up to five entities involved:

1. The transmission provider (TRANSCO).
2. The local distributor (DISTCO), or the "wires" company.
3. One or more independent power producers (IPPs) or market power producers (MPPs).
4. Retail energy marketers (RETAILCOs) or energy service companies (ESCOs).
5. The end user.

A. RMS variations agreements

Some of the key issues that should be addressed are

1. The number of interruptions expected each year.
2. The number of voltage sags below a certain level each year. The level can be defined in terms of a specific number such as 70 or 80 percent. Alternatively, it can be defined in terms of a curve such as the CBEMA or ITI curve.

3. The means by which end users can mitigate rms variations.
4. Responsibilities of utilities in analyzing the performance of the power delivery system, following up with fault events, etc.
5. Maintenance efforts to reduce the number of faults for events within the control of the utility.

B. Harmonics agreements

Agreements on harmonics should reflect this bilateral nature. Some of the key issues that should be addressed are:

1. Definition of the PCC.
2. Limitation of the harmonic current distortion level at the PCC to that set by IEEE Standard 519-1992 or to another value allowed by a specified exception.
3. Periodic maintenance schedules for filters and other mitigating equipment. Some equipment will require constant monitoring by permanently installed devices.
4. Responsibilities of utilities, such as

(*a*) Keeping the system out of harmonic resonance

(*b*) Keeping records about new loads coming onto the system (this is getting tougher to do with deregulation)

(*c*) Performing engineering analyses when new loads come onto the system to prevent exacerbation of existing problems

(*d*) Educating end users about mitigation options

(*e*) Periodic monitoring or constant monitoring by permanently installed devices to verify proper operation of the system.

5. Definition of responsibilities for mitigation costs when limits are exceeded. Is the last end user who created the excess load responsible or is the cost shared among a class of end users and the utility?

Monitoring of the power quality and computation of the service indices are of very high importance. Detroit Edison installed a power quality monitoring system at over 50 of the three customers' locations throughout its territory. The power quality monitoring system allows Detroit Edison to determine the frequency and severity of voltage sags that occur at the customer locations. Some of the key details follow.

The interruption targets for the DaimlerChrysler and General Motors locations are either 0 or 1. This means that only one interruption is allowed at some of these locations and none at other locations in each calendar year.

Five rules that establish a subset of sags that qualify for payment are:

1. The rms voltage on any of the three phases must drop below 0.75 pu. There is no minimum duration for qualifying voltage sags; all durations are eligible. The threshold was established based on the ITI curve and discussions with the customers. Actual experience is not a factor in the sag qualification.
2. Voltage sags that are caused by the customer are excluded from the qualifying sag list.
3. Voltage sags that are measured on a nonloaded feeder are not qualifying. This is automatically determined in the PQ View program from the maximum load current. Rules 2 and 3 are in place to ensure that the performance is only evaluated at the PCC.
4. Only the worst voltage sag (lowest rms voltage) in a 15-min interval at each location can qualify. The 15-min interval begins when the first sag in a chronological list of sags is detected and ends when either the last sag in the interval is detected or at a point 15 min after the first. Voltage sags that occur after that 15-min interval are considered part of the next interval and are assessed separately. This type of processing is called 15-min temporal aggregation with spatial aggregation by location.
5. If a voltage interruption is measured during a 15-min interval, then any voltage sags that are also measured at the location will not qualify.

The SMC agreement allows sag score targets to be recomputed for the eight groups at the start of each calendar year. The group sag score targets are determined by computing the average group sag score totals for the voltage sag data collected.

The payment due to a location is computed by determining the sag score sum in excess of the sag score target multiplied by the SGPA subject to an annual payment cap.

V. POWER QUALITY INSURANCE

The premium PQ service program uses a business model involving premiums and claims. The utility offers PQ services under an insurance plan. Customers pay premiums for a defined level of service, and the utility pays the customer directly for events exceeding the terms of that service. Customers are motivated to pay a premium to reduce the uncertainty and/or the expected value of their damage costs. Utilities assume the financial risk associated with the claims in exchange for a return on the aggregate premiums. The utility's insurance service can make use of a purely financial policy or a policy that incorporates investments in PQ equipment or service. In both cases, the critical advantage of the insurance approach over a cost-of-service approach is that it allows customers to self-select an appropriate solution from policies that are designed without use of customer damage cost data.

(*i*) *Insurance as a financial product :* The utility can create a purely financial insurance product in which it offers to pay customers for reliability events covered by the policy, and customers pay premiums. Utilities will use customer location to estimate an expected frequency of claims.

(*ii*) *Incorporating PQ investments into insurance products :* A utility can greatly increase the types of PQ insurance products it can offer if it considers the role that PQ investments can play. By making such investments, the utility can offer insurance products with higher payout ratios and improve customer service quality

(*iii*) *Designing an insurance policy :*

Table 3: Proposed Claim Payment Structure for PQ Insurance in Five General Categories.

PQ Category	*Claim Payment Structure*
RMS Variations	$/event categorised by amount of variation as necessary. Incorporate any impact of duration into an event total.
Sustained Interruptions	$/event $/hour
Voltage Regulations	$/hour categorised as necessary by magnitude indices.
Harmonics	$/hour categorised as necessary by component and magnitude indices.
Transients	$/hour categorised as necessary by magnitude indices.

The goals of a PQ insurance scheme are to recover the cost of providing the plan, treat all customers within a group equally at cost-based premiums, improve efficient use of resources, and be comprehensible and acceptable.

(*a*) *Fairness :* An insurance scheme is considered fair if the expected cost of claims equals the premiums paid. For example, assume a customer's value of service (net of the energy rate) to be $\$x$/kW, which is unobservable. Suppose the probability of an outage is r and the expected benefit to the customer of electricity consumption is $(1 - r)x$. Now consider an insurance scheme in which a premium of $\$p$/kW results in an insurance payment of $\$x$/kW in the event of an outage. This means that the customer by buying insurance will obtain $[rx + (1 - r)x - p] = x - p$ with certainty. The customer will buy the insurance if $x - p > rx$ when $p = (1 - r)x$, the insurance scheme is fair and cost-based.

(*b*) *Implementation :* Designing a basic area financial insurance option involves the following steps:

Step 1. Compute the area-specific probability of outage using historic outage data. For example, the probability of an outage with a duration of more than 1*h* is

$$r(>1h) = \frac{\text{Annual unserved hours for such outages}}{8760h}$$

Step 2. Compute the fair insurance premium for a given payoff. For example, if payoff = $1/kW unserved and $r(>1h) = 0.0002$, the fair premium is $0.0002/kW unserved.

Step 3. Adjust the premium to collect margin. Suppose the adder is $0.0001/kW unserved; then the posted premium is $0.0003/kW unserved.

Step 4. Design service conditions.

VI. POWER QUALITY STATIC ESTIMATION

Ideally, power quality state estimation would work best with fully capable PQ monitors near the substation and on all the major branches of a three-phase feeder. The limitations are three levels of monitoring are listed in the table.

Monitor configuration level	*Capabilities*
1. Substation only	Adequate for cases in which it can be assumed all customers on the feeder see the same voltage.
2. Substation + Customer side monitors	Accuracy of prediction of voltage along the feeder is considerably enhanced if customer sites are significantly downline from the substation. However, it is still difficult to predict fault location accurately since the fault current path is not known.
3. Substation + PQ monitors on main three-phase feeder	Should yield the most accurate results. Improves on capabilities gained by adding customer side monitors by providing information on the feeder current flow.

VII. CONCLUSION

Recommended indices are available for characterizing distribution power quality performance. However, little benchmarking information is available using these indices in a consistent manner. There is a need for ongoing system performance assessment and benchmarking so that system performance expectations can be refined. For voltage sags and momentary interruptions, it is very difficult to make general predictions or requirements for system performance. However, it is important for utilities to be able to characterize the performance of individual systems in the same way that reliability levels are characterized. This continues to be important information for industrial and commercial customers.

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