IEEE Recommended Practice for Evaluating Electric Power System Compatibility With Electronic Process Equipment

Sponsor

Standards Coordinating Committee 22 on Power Quality

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Abstract: A standard methodology for the technical and financial analysis of voltage sag compatibility between process equipment and electric power systems is recommended. The methodology presented is intended to be used as a planning tool to quantify the voltage sag environment and process sensitivity. It shows how technical and financial alternatives can be evaluated. Performance limits for utility systems, power distribution systems, or electronic process equipment are not included.
Keywords: power quality, power quality monitoring, sensitive equipment, voltage loss, voltage sags

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Introduction

(This introduction is not part of IEEE Std 1346-1998, IEEE Recommended Practice for Evaluating Electric Power System Compatibility With Electronic Process Equipment.)

The proliferation of microprocessors and power electronics in commercial and industrial facilities has greatly increased the financial losses of power quality to business. There are no large-scale studies on the cost of power quality to business. However, estimates of the cost range up to tens of billions of dollars (U.S.) each year in the U.S. alone due to inattention to compatibility. Before electronics invaded lighting, machine tools, and heating and cooling equipment, power compatibility meant verifying that the equipment nameplate voltage and frequency were consistent with the supply. Unfortunately, the electronics in today's equipment that provide expanded features and flexibility demand more careful attention to their application with the power system.

Traditionally, power quality has focused on the technical issues associated with the electric supply. The emphasis has been on fixing existing problems rather than preventing future problems. This document recommends a method to evaluate the power quality environment and process sensitivity. First, a method to determine the financial loss due to the disruption is presented. Then a method for determining the annual number of power quality related disruptions is provided. From that information, the financial cost of compatibility can be found and alternatives to reduce the loss can be evaluated.

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IEEE Recommended Practice for Evaluating Electric Power System Compatibility With Electronic Process Equipment

1. Overview

1.1 Purpose

The purpose of this document is to recommend a standard methodology for the technical and financial analysis of compatibility of process equipment with an electric power system.

This recommended practice does not intend to set performance limits for utility systems, power distribution systems, or electronic process equipment. Rather, it shows how the performance data for each of these entities can be analyzed to evaluate their compatibility as a system in financial terms. The recommended methodology also provides standardization of methods, data, and analysis of power systems and equipment in evaluating compatibility so that compatibility can be discussed from a common frame of reference.

1.2 Scope

This recommended practice is intended to be applied at the planning or design stage of a system where power supply and equipment choices are still flexible and incompatibilities can be resolved. The cost of trying to fix an incompatible system after installation is hundreds to thousands of times more than addressing it in the planning stage. Consequently, this document does not discuss troubleshooting or correcting existing power quality problems.

Since voltage sags present the greatest financial loss due to compatibility, this first edition of the recommended practice develops a compatibility methodology specifically for voltage sags. However, compatibility encompasses many other issues such as harmonics, surges, radiated interference, etc. As better information is available on the environment/equipment response and experience is gained with this approach, compatibility methodologies will be developed for other issues. To aid the evaluation of the non-sag compatibility issues, a guideline list is included in 4.3.

This recommended practice does not discuss technical options to improve compatibility. The alternatives are so numerous and evolving so quickly that such a listing would detract from the basic purpose of the document, which is to plan for compatibility.

Clause 4 is the heart of the document and contains the worksheets used for evaluating compatibility. Completed worksheets provide an estimate of the number of disruptions, the financial loss, and financial analysis of alternatives associated with the compatibility of a system. The annexes provide the background and techniques necessary to apply the worksheets. They are financial analyses, power system performance, equipment performance, and constructing the compatibility charts. An example analysis is provided in Annex E.

2. References

This recommended practice shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision shall apply:

IEC 61000-4-11 (1994), Electromagnetic compatibility (EMC)—Part 4: Testing and measuring techniques—Section 11: Voltage dips, short interruptions and voltage variations.[1]

IEEE Std 100-1996, IEEE Standard Dictionary of Electrical and Electronics Terms, 6th Edition.[2]

IEEE Std 1159-1995, IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std 1250-1995, IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances.

3. Definitions

3.1 Technical terms used in this recommended practice

3.1.1 dip: *See* **sag**.

3.1.2 dropout voltage: The voltage at which a device will release to its de-energized position (for this document, the voltage at which a device fails to operate).

3.1.3 interruption, momentary (power quality monitoring): A type of short duration variation. The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time period between 0.5 cycles and 3 s.

3.1.4 interruption, sustained (power quality monitoring): A type of long duration variation. The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time greater than 1 min.

3.1.5 interruption, temporary (power quality monitoring): A type of short duration variation. The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time period between 3 s and 1 min.

3.1.6 momentary (power quality monitoring): When used as a modifier to quantify the duration of a short duration variation, refers to a time range at the power frequency from 30 cycles to 3 s.

[1]IEC publications are available from IEC Sales Department, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse. IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[2]IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

3.1.7 noise: Unwanted electrical signals in the circuits of the control systems in which they occur. (For this document, “control systems” is intended to include sensitive electronic equipment in total or in part.)

3.1.8 nominal voltage (Vn): A nominal value assigned to a circuit or system for the purpose of conveniently designating its voltage class (as 208/120, 480/277, 600).

3.1.9 notch: A switching (or other) disturbance of the normal power voltage waveform, lasting less than 0.5 cycles, which is initially of opposite polarity than the waveform and is thus subtracted from the normal waveform in terms of the peak value of the disturbance voltage. This includes complete loss of voltage for up to 0.5 cycles.

3.1.10 oscillatory transient: A sudden, nonpower frequency change in the steady-state condition of voltage or current that includes both positive or negative polarity value.

3.1.11 overvoltage: When used to describe a specific type of long duration variation, refers to a measured voltage having a value greater than the nominal voltage for a period of time greater than 1 min. Typical values are 1.1 to 1.2 pu.

3.1.12 phase shift: The displacement in time of one waveform relative to another of the same frequency and harmonic content.

3.1.13 sag: A decrease in rms voltage or current at the power frequency for durations of 0.5 cycle to 1 min. Typical values are 0.1 to 0.9 pu. *Note:* To give a numerical value to a sag, the recommended usage is “a sag to 20%,” which means that the line voltage is reduced down to 20% of the normal value, not reduced by 20%. Using the preposition “of” (as in “a sag of 20%,” or “a 20% sag”) is deprecated.

3.1.14 sustained: When used to quantify the duration of a voltage interruption, refers to the time frame associated with a long duration variation (i.e., greater than 1 min).

3.1.15 swell: An increase in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 min. Typical values are 1.1 to 1.8 pu.

3.1.16 transient: Pertaining to or designating a phenomenon or a quantity which varies between two consecutive steady states during a time interval that is short compared to the time scale of interest. A transient can be a unidirectional impulse of either polarity or a damped oscillatory wave with the first peak occurring in either polarity.

3.1.17 undervoltage: When used to describe a specific type of long duration variation, refers to a measured voltage having a value less than the nominal voltage for a period of time greater than 1 min. Typical values are 0.8–0.9 pu.

3.1.18 voltage dip: *See* **sag**.

3.1.19 voltage imbalance (unbalance), polyphase systems: The ratio of the negative or zero sequence component to the positive sequence component, usually expressed as a percentage.

3.2 Financial terms used in this recommended practice

3.2.1 bill of materials: A report showing the material costs of a single unit of product; listing of all unit components with part numbers, quantities, and supplier prices.

3.2.2 payback: A financial analysis technique where the cost to implement a project is compared to the annual savings due from the project.

3.2.3 unloaded labor rate: Variable costs of labor per hour, excluding all forms of benefits such as vacations, medical insurance, retirement, etc.

3.2.4 weighted average cost of capital: The average interest rate used in financial analysis by business for capital projects.

3.2.5 work in progress: Production units in a semifinished state, either being processed or waiting in buffer inventories between processing steps.

3.3 Abbreviations used in this recommended practice

ASD	adjustable speed drive
BIL	basic impulse level
BOM	bill of materials
EUT	equipment under test
MOV	metal oxide varistor
PLC	programmable logic controller
PWM	pulse-width modulation
WACC	weighted average cost of capital
WIP	work in progress

4. Compatibility evaluation

4.1 Introduction

This clause provides the charts that should be used for evaluating voltage sag compatibility. Instructions on how to gather the necessary data and apply the format are contained in the annexes. The content of the annexes is as follows:

— *Annex A, Financial evaluation*—A normative annex that discusses how to determine the cost of a process disruption and how to evaluate payback.

— *Annex B, Power system performance*—An informative annex that explains how to evaluate the voltage sag environment of the power supply system.

— *Annex C, Equipment performance*—An informative annex that describes how to evaluate the voltage sag susceptibility of process equipment.

— *Annex D, Constructing coordination charts*—A normative annex that shows how to apply the graphical procedure to determine the annual compatibility disruption rate.

— *Annex E, Example*—An informative annex that provides an example of the compatibility methodology applied to a fictitious system.

Equipment sensitivity guidelines are listed in 4.3 for discussion of a broader range of compatibility issues.

4.2 Compatibility templates

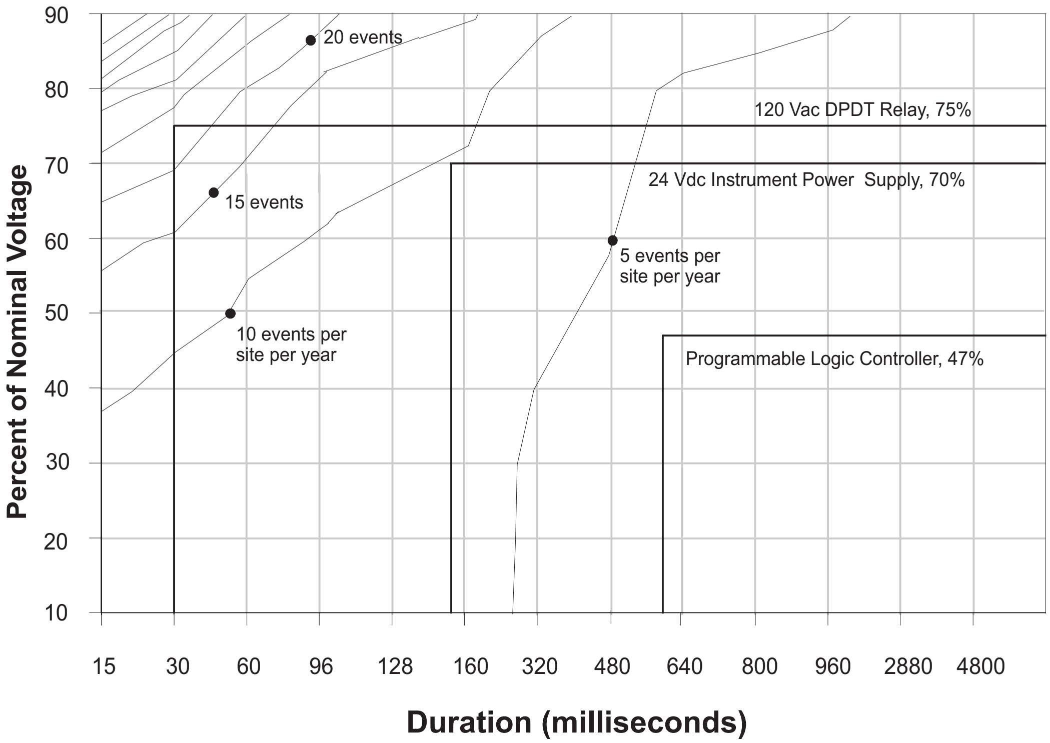


Figure 1—Sample overlay of sag environment and equipment susceptibilities

Investment	Return
One-time capital outlay	Annual benefit
+ Installation	– Ongoing annual expense
Net investment	Net annual return

Payback (months) = (net investment/net annual return) · 12

Figure 2—Sample compatibility impact financial analysis form

4.3 Compatibility guidelines

This subclause provides a list of selected questions that may be posed to the equipment supplier during the review of equipment specifications. These guidelines are optional and are not part of this recommended practice.

a) *How much can the supply voltage sag, and for how long, before equipment malfunctions?*
Inadequate: A fixed value of some magnitude (i.e., 20%–30%) with no mention of duration or unbalance.
Preferred: A valid example would be a graph showing both magnitude (from nominal to zero) and duration (from zero to seconds), voltage imbalance tolerance and point on wave tolerance. Onsite testing as a part of the acceptance testing of the installed complete machine can be part of the purchase contract.
b) *What are the steady-state voltage tolerances?*
Inadequate: ±5%.Typically tight tolerances of this nature are trying to improve ride-through characteristics using unrealistic criteria.
Preferred: Values can be a minimum of ±10% of the equipment rating. All machine components can be rated to the same value.
c) *How long can zero voltage be tolerated?*
Inadequate: A time value without load or process dependency.
Preferred: Test results of the composite machine can be provided. Onsite tests as a part of the acceptance testing of the installed complete machine can be part of the purchase contract. Orderly shutdown is able to be maintained.
d) *What is the machine's transient voltage withstand capability?*
Inadequate: The equipment is protected by MOV arresters with ____ joule of protection.
Preferred: The equipment has a fully coordinated transient suppression scheme as demonstrated by curves of let-through voltage per amp of transient energy vs. the withstand curves of electronic components and basic impulse level (BIL) of internal circuitry. This scheme is adequate in a Class B environment with grounding sufficient for a frequency range of 3 kHz to 1 GHz.
e) *How much voltage distortion can the equipment tolerate?*
Inadequate: It meets all standards, such as IEEE Std 519-1992 [B22][3].
Preferred: Voltage distortion tolerance of <10%, crest factor of <2.5, and notching of <__ V·μs can be tolerated without affecting the equipment.

[3]The numbers in brackets preceded by the letter B correspond to those of the bibliography in Annex F.

Annex A

(normative)

Financial evaluation

A.1 Introduction

This annex explains a method to evaluate and analyze the financial impact of compatibility. It is intended to be generic in coverage and does not necessarily represent any particular type of business. Although generic guidance is provided, the user should very carefully ensure that all applicable costs particular to the user's specific operation are identified if the analysis is to provide meaningful results. The method presented is intended to identify general costs associated with power quality disruptions and is not intended to function as an accounting system. In other words, for compatibility evaluation, it is only necessary to identify approximate losses. Determining accurate losses would be more appropriate after the magnitude of the problem is known and resources are available for further investigation.

A method to analyze the overall cost of compatibility is also presented based on simple payback. Individual businesses may have different methods or criteria than those presented here. However, it is intended to provide a technique that can quickly identify cost saving potentials associated with compatibility.

A.2 Cost of disruption

There are several suggestions to help assure a successful cost of disruption evaluation. First, involve everyone who is impacted by the disruption in estimating the loss. The most obvious are those familiar with the operational impact of equipment disruption such as front-line workers, supervisors, and maintenance technicians. The list should also include finance and accounting personnel who may have established methods of estimating financial losses associated with downtime. Sales and marketing personnel can represent the impact on customers and management can provide the longer-term, strategic consequences of disruptions. The evaluation requires a balance of both high-level and detailed perspectives. Data from the information tracking system of the business should be used wherever possible.

Second, if for some aspects of the analysis it is not possible to obtain documented costs, use the best estimate of someone experienced with the process. Their estimates are often later shown to be surprisingly accurate.

Finally, where the personnel involved are not sufficiently knowledgeable or objective to offer good estimates, observational sampling may be applied. Keep in mind this guideline is only intended to expose approximate costs.

The costs discussed here are listed in the cost of disruption evaluation form shown in Figure A.1. A separate tabulation should be generated for each compatibility evaluation.

A.2.1 Downtime related

A.2.1.1 Lost work

The product or service is not generated for a period of time until recovery is complete. A process flow of the product or service should be developed for the other supplied processes (either inside or outside the facility) or customers to determine when and how they are affected.

Downtime Related

Increased buffer inventories (value of incremental inventories · WACC)	______
Lost work	
Idled labor	
Disrupted process (man-h · unloaded labor rate)	______
Starved process (man-h · unloaded labor rate)	______
Lost production	
Lost profits (unbuilt product · profit margin)	______
Makeup production	
Overtime labor + premium	______
Overtime operating cost	______
Expedited shipping premiums	______
Late delivery fees	______
Cost to repair damaged equipment	
Repair labor	______
Repair supplies	______
Repair parts	______
Cost of replacement part availability	
Expedited shipping of parts	______
or	
Carrying cost of parts	______
Cost of recovery	
Secondary equipment failures (treat as repairs)	______
Recovery labor inefficiency	______
Product quality	
Replacement value of scrap (BOM value + labor value)	______
Blemished product lost profit margin	______
Rework cost	
Labor	______
Manufacturing supplies	______
Replacement parts	______
Miscellaneous	
Customer’s dissatisfaction	
Lost business	______
Avoided customers due to longer lead time	______
Fines and penalties	______
Other	______
TOTAL	______

Figure A.1—Sample cost of disruption evaluation form

On manufacturing lines, there may be inventory buffers between processes (Work In Progress, or WIP) to prevent minor disruptions from cascading to downstream processes. These WIP inventories may be increased to reduce the impact of future disruptions as a preventive measure. The capital tied up in WIP can be found by estimating the average number of units in these buffers and multiplying by the value of the components of a partially assembled unit, usually with the aid of operation’s bill of materials (BOM). This capital, multiplied by the finance group’s cost of capital (Weighted Average Cost of Capital, or WACC), yields the cost to the business of carrying excess inventory.

However, where insufficient WIP buffers exist in a manufacturing line, or in service industries where WIP cannot be carried, processes downstream of a disrupted operation will eventually be disrupted themselves. Stoppage of downstream work is referred to as starving processes. The cost is the cost of paying idle employees at the starved processes. Supervision should be able to estimate the average idle man-hours of labor (those employees who cannot be deployed to other operations, conduct preventive maintenance, perform housekeeping, etc.), and accounting should be able to provide the unloaded (i.e., no benefits) labor rate.

If lost work can be recovered with overtime, the additional costs associated with overtime should be added. This includes the labor costs, overtime premiums, and the additional costs to operate the facility and equipment outside normal schedules. The operations and accounting groups should be able to help estimate these costs. Furthermore, there may be additional transportation costs for expedited deliveries. Trucks may be delayed for departure and the user charged for the delay (demurrage). Expedited shipping may also be needed to compensate for the production delay. Some customer contracts may have late delivery penalties. The sales group would have information on the history of and conditions for these penalties.

However, for a work disruption taking place at a facility at maximum capacity where the lost work cannot be made up at the impacted location or another location, the resulting downtime should be shown as lost profits to the business for the number of units that could not be created and delivered.

A.2.1.2 Repair

Unlike lost work, the repair of equipment damaged often generates a paper trail available from either maintenance or operations. The exact components repaired will depend on the circumstances.

There are several types of costs involved. First, there is the cost of hardware replaced, either parts or complete machinery. In addition to the cost of buying the replacement hardware, there are costs associated with holding repair parts in inventory (which should be treated similarly to WIP carrying costs, above) and with any special transportation costs for expedited shipping of components. Second, there is repair labor. The business may have repair personnel on staff and their labor may not represent an additional cost unless they must work overtime. Alternatively, an outside firm may be called to perform the repairs. In such a case all the repair labor costs should be included. Finally, there may be delayed repairs. The equipment is temporarily repaired to bring the line back up, but additional, later work is necessary to complete the job.

A.2.1.3 Recovery

Recovery related costs are those costs associated with returning to normal operation, including labor and production related inefficiencies. Labor costs should also be included in the consideration.

Both industrial and commercial equipment recovering from a crash can exhibit secondary failures. This may be due to the additional stresses of an uncontrolled shutdown or latent failures that are exposed by the cycling. They should be included in the analysis.

There is also a psychological effect on the work force of their process unraveling, especially of a complex process. This is particularly true if the incident is overwhelming and appears beyond the employee’s control to prevent. Employees may not feel disposed to restore rhythm if the disruption is near the end of the shift. Full recovery may only be possible with the next shift or next day. Line supervisors are the best source of information about employee productivity changes after a disruptive event.

A.2.2 Product quality

The losses due to product quality are scrap and rework.

Scrap is product that is damaged beyond economic repair by the disruption. The loss is the value of the product at the point of damage in the process. (It may be helpful to conduct this calculation by determining replacement cost, i.e., the cost of replacing damaged product by good product at a similar stage of processing.) Operations should have scrap information, both quantities and costs. These costs may be partially offset if damaged product may be sold as seconds at lower price. Sales should be aware of such opportunities.

Rework is repairing damaged product to the point it is acceptable, including both labor and materials. Again, the operations group should be tracking rework data. In information technology applications, rework is usually the most significant cost. Data must be recreated, inputted, and or verified. In research and development work often entire experiments may need to be repeated.

A.2.3 Miscellaneous

There are other costs that are less quantifiable than those discussed above. This subclause outlines some of these with possible metrics. Where the investigation yields what appear to be truly uncertain estimates, it is better to leave these numbers out of the main cost/benefit argument and present them as separate, supporting figures.

Customers may be dissatisfied with late delivery or delayed service, resulting in potential loss of reputation and, with it, customer contracts. The sales department may have anecdotal evidence of sales, and profits, lost due to failed deliveries. By working with operations to develop a probability for missed deliveries based on disruptions, one can estimate the number of times deliveries may be missed annually to a customer. Using this figure, with past anecdotes and examples as guides, sales may be able to project a lost sales figure.

Sales may be quoting excessively long delivery lead times to cover potential downtime problems and ensure that the company can always meet delivery schedule. These longer lead times may be driving away potential customers. If power disruptions are a significant cause of long downtimes (which maintenance or operations should know), the reduction or elimination of disruptions should allow a shorter delivery lead time. Given an estimate of how many hours or days the lead time could be shortened, sales may be able to estimate new business.

Disruptions may jeopardize employee or customer safety, such as in the chemical or health care industries. Process disruption may lead directly to an environmental release that can result in a government fine and bad publicity. There may be costs associated with possible litigation associated with other aspects of the event. Safety hazards or actual injuries may result in safety agency fines or additional medical/insurance costs.

Determine the bad-case and worst-case scenarios with associated probabilities of such events, before approaching the relevant departments for assistance.

A.3 Financial analysis of alternatives

With an estimate of the annual number of compatibility related process disruptions and an estimate of the cost of disruption, alternatives may be evaluated. The alternatives include, but are not limited to, buying less sensitive equipment, contracting for service guarantees from the electric utility, or adding mitigating devices. Some of the alternatives add new equipment or increase the cost of planned equipment. These are initial or capital costs. Other costs are outlays incurred throughout the life of the project. These are operating costs. The incremental cost of a method to improve compatibility is compared against the resulting savings. If the savings exceed the costs over a specified period of time (such as two years), the project can be considered viable.

It is assumed that the business has a well-defined project approval process, with appropriately rigorous analyses based on the present values of the resulting net cash flows. The following is meant to supplement, not supplant, a more traditional cash flow approach.

Before developing the rigorous analyses needed for capital and expense requests, it is often helpful to have developed a quick "back of the envelope" estimate of costs vs. benefits. The quick estimate should be comprehensive in breadth but not necessarily in depth. All potential costs and benefits should be examined, but the projected numbers need not be accurate to the last detail. This estimate gives an indication of the magnitude of the net benefit. Indeed, if estimated benefits are significantly greater than projected costs, more detailed, traditional analyses may not be necessary for project approval.

Figure A.2 outlines the major components of such an analysis. Investment consists of any one-time cost required to implement the changeover project. This could include the incremental cost of less sensitive process equipment determined by requesting two proposals from the equipment supplier for normal and less sensitive versions. There may be additional hardware costs that allow quicker recovery from a disruption. Additional equipment to mitigate incompatibilities may be added, such as uninterruptible power supplies installed at process electronics or "custom power" equipment to supply conditioned power for part or all of a facility. The costs to install the equipment and remove old equipment should also be added.

The annual benefit is the reduced down time costs as a result of the project based on the reduction of disruptions and the cost per disruption. The annual number of disruptions prevented by the project is found from the sag environment/equipment sensitivity compatibility chart explained in Annex D. The annual number of disruptions prevented is multiplied by the cost per disruption derived in A.2 to determine the annual benefit. The net annual return is found by netting out the outgoing annual expenses as a result of the project. This can include the maintenance and electrical energy costs associated with operating mitigating equipment or the additional cost of an electric utility premium service contract.

The payback period is the number of months of benefits required for the project to break even. In this case, it is the net investment divided by the net annual return. If more accuracy is desired, the net present value can be calculated of the one-time investment set against a stream of net annual returns yielding the total value of the project. However, the simple payback calculation should be sufficient for the purposes of estimation. Generally, a payback of less than 24 months signals a project that should be critically examined with more rigorous analysis.

Investment	***Examples***	**Return**	***Examples***
One-time capital outlay	*Enhanced equipment, custom power*	Annual benefit	*Cost of reduced downtime*
+ Installation	*Installation cost*	– Ongoing annual expense	*UPS maintenance, premium utility service*
Net investment		Net annual return	

Payback (months) = (net investment/net annual return) · 12

Figure A.2—Compatibility financial analysis

Annex B

(informative)

Power system performance

B.1 Introduction

Power system performance is determined by the entire electrical system from the generator to the device powered. This system can be divided into two components: the facility system and the utility system. Each of these plays a significant role in the proper operation of electronic process equipment. Problems on either system can have a drastic impact on the profitability of a facility. Since a significant number of the total sags originate on the utility system, background regarding utility systems is useful in understanding the origins of sags. How sag data may be found for a particular site will be discussed and example data placed in the form of the voltage sag coordination chart will be provided. There are several aspects of facility operation that can exaggerate the susceptibility of a facility to sags, and those will be discussed.

This annex discusses the most common types of problems, equipment, and configurations. It is not intended to be a comprehensive description of power systems, and generalizations will be made without repeated qualifications.

B.2 Utility system

B.2.1 Design

Utility power systems are composed of two distinct divisions: transmission and distribution. The most significant differences between the two are voltage and interconnectivity. The following description should be considered typical. Nevertheless, many variations exist.

The transmission system is an interconnected system of high-voltage lines that terminate at substations. The operating voltages of transmission systems vary from approximately 69 kV to around 1000 kV. Figure B.1 shows a simple transmission system illustrating how most of the substation buses have more than one source. Also referred to as a network system, this offers a high degree of reliability because power can be maintained to most buses even with loss of a line or source.

The distribution system is a radial system, which steps the voltage down from the transmission system with a transformer. Typical operating voltages for the distribution system are from 34.5 kV down to 2.4 kV. Since there is a transformer between the two systems, the system impedance of the distribution circuits is somewhat higher than the transmission system on a per unit basis.

B.2.2 Sag occurrence

Voltage sags result most often from the flow of fault current through the power system impedance to the fault location [B10]. Thus, sags occur when a fault occurs on either of these systems. Depending on which of the two systems the fault occurs, it can affect a large or a relatively small number of customers. For a fault on a 230 kV transmission line, a sag may affect sensitive equipment up to hundreds of kilometers away from the fault. An example of the distances at which at fault is noticed is shown in Table B.1 [B7]. It is noteworthy that a fault on a neighboring utility company can cause user problems on the local utility.

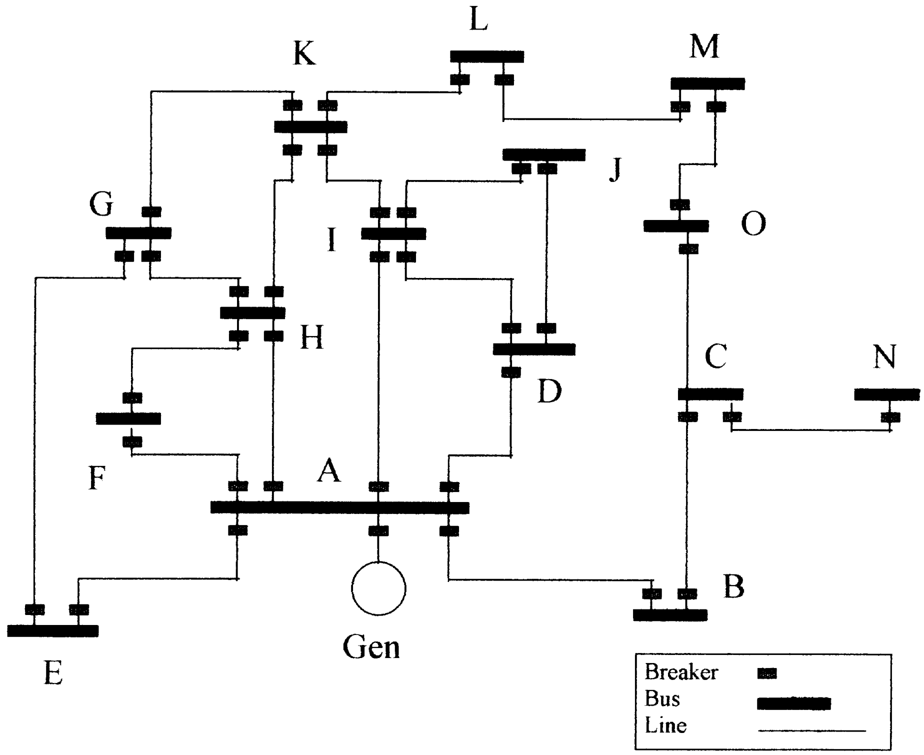


Figure B.1—Transmission system showing substations and line sections

Table B.1—Example of distance at which fault leads to a noticeable sag

Voltage	Available short-circuit current		
Level	10 kA	25 kA	50 kA
230 kV	250 km	100 km	50 km
100 kV	110 km	45 km	22 km
50 kV	50 km	20 km	11 km

An example of a voltage sag is shown in Figure B.2. This sag was caused by fault current initiated when lightning struck a transmission line. In this case the BIL of the line was exceeded, allowing the lightning to flash over to the tower. The lightning cleared in a matter of microseconds, but the ac current continued to flow in the path created until the circuit breakers at the ends of each line segment open. The breakers are generally designed to restore power to the line segment after a predetermined amount of time, typically a few seconds. This is because, like lightning, most faults are temporary.

The amount the line is depressed depends on the available fault current at that location and the fault impedance. The farther away (electrically) a fault occurs from a facility, the less severe the magnitude of the voltage sag will be. A sag that drops the voltage to 73% of nominal at B (see Figure B.3) due to a fault between C and B may only be down to 90% of nominal at L. In this example, the sag experienced is noticeable over a sizable part of the system shown in the figure.

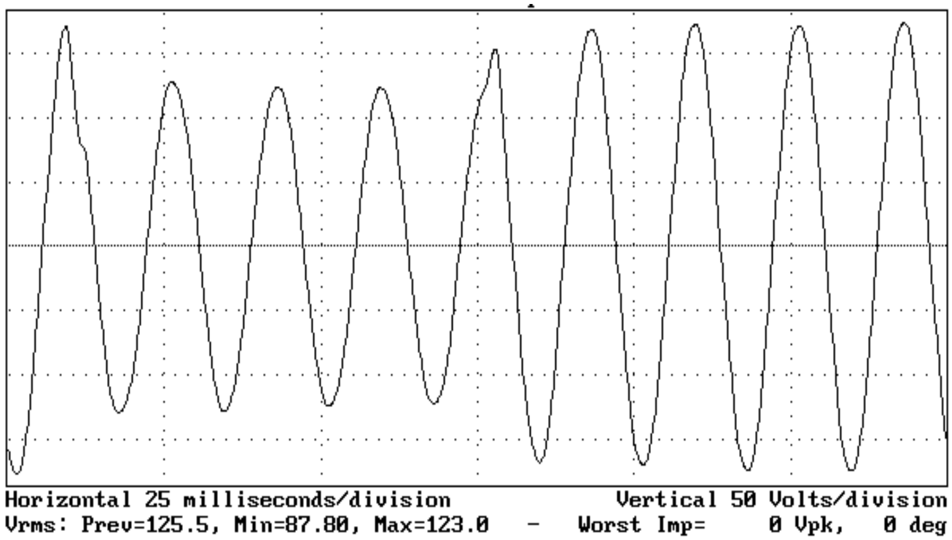


Figure B.2—Example of a voltage sag to 73% with a duration of 0.058 s

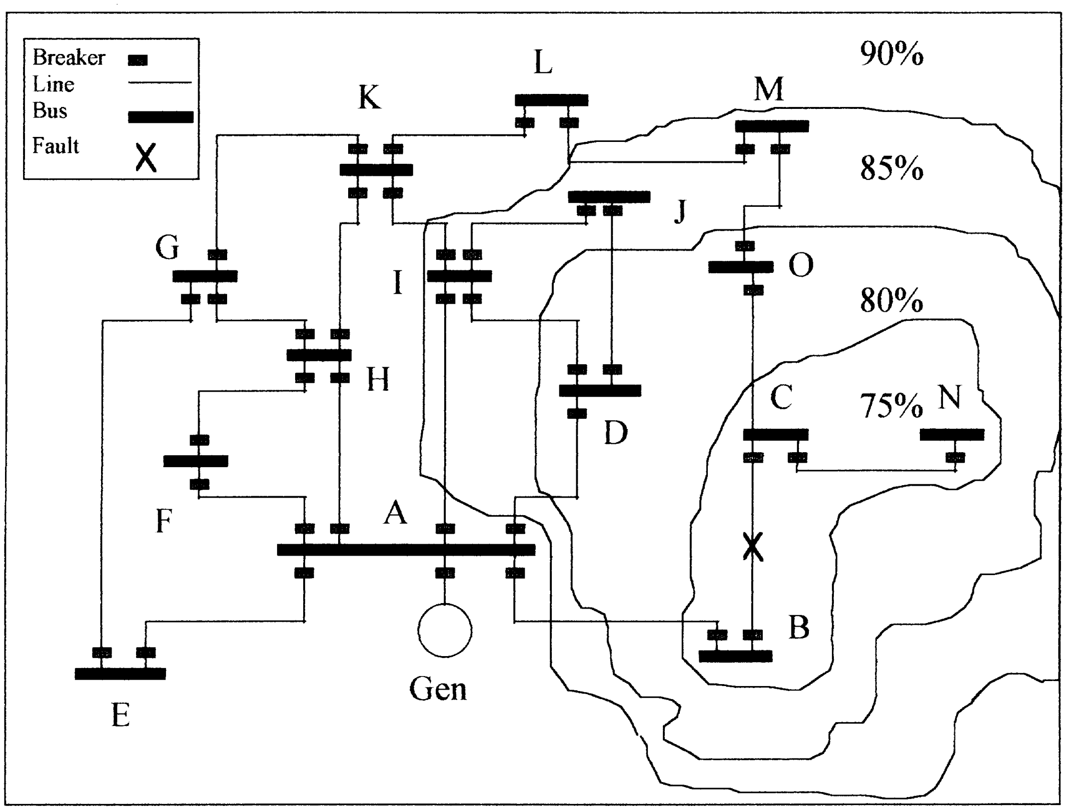


Figure B.3—Magnitude of the sag by areas

A fault on a radial distribution system is somewhat different. Due to the impedance of the step-down transformer and the radial configuration, most faults will affect only the users who share the transformer. This includes all the users on the other circuits fed by the transformer. The users on the faulted circuit on the load side of the operating protective device will see a sag followed by a permanent or temporary interruption. Other users on that circuit and other circuits on the transformer will see a sag until the fault is cleared by the protective device.

B.2.3 Determining voltage sag activity

Voltage sag data is necessary to perform a compatibility evaluation. Utilities may not have sag information, especially for specific areas of their service territory. The sag information may be actual measurements, predicted performance, or "typical" data.

Actual measured information for the facility gathered over several years is accurate as long as the supply system does not change significantly in the future. However, even utility specific data varies to some degree by year, season, location, voltage level, and other factors. Projecting from history may not be any more accurate than typical data, since distribution circuits are frequently reconfigured.

Where the sags are measured is important. Utility data, when provided, may be at the utility connection to the facility, the substation, or a representative nearby site. But the equipment is connected at a location inside the plant where the sags may not be identical to those at the utility feed due to the facility's electrical design. It is best to measure sag data as close to the actual feed of the proposed equipment as possible. If actual location data is not available, apply judgment in the use of the data that can be obtained.

If measured data is not available, it is possible to install monitors and collect sag data. In this situation, the longer the data is collected, the more reliable it will be. Information on recommended methods and equipment to collect power quality data is contained in IEEE Std 1159-1995. The biggest influence on the frequency of sags is the weather. A year with above-average storms can significantly skew the data. It may take several years to accumulate accurate data.

Predictive techniques use historical failure rates to estimate the supply sag characteristics. Measured sag data is not necessary as long as equipment failure rates are known. The IEEE Gold Book (IEEE Std 493-1997 [B15]) provides guidance on predictive techniques for voltage sags. Such techniques allow a variety of scenarios to be analyzed as well as provide a means to estimate performance at new sites where there is no historical sag data.

Without measured data and where lack of time or information precludes predictive analysis, example data may be used. Such data does not establish a particular utility's service reliability. However, it does represent a sample of power system performance data.

B.3 Example sag data

The following example develops the supply system sag performance based on data supplied by the Electric Power Research Institute's Distribution System Power Quality Project [B12]. The data is from 222 utility distribution feeders in the USA from 1 June 1993 to 1 June 1995. The method of analysis is discussed in Annex D.

Table B.2 shows the number of sags per year in each bin. For example, there were 3.9 sags per site per year with a magnitude between 60% and 70% of nominal voltage and a duration between 0.0 and 0.2 s.

Table B.3 shows the total sags that were equal to or more severe than the magnitude and duration headings. For example, there were 7.4 sags of 80% voltage or less *and* durations of 0.2 s or longer per site per year.

Figure B.4 shows the supply system sag performance contours.

Table B.2—Example utility voltage sag data

Magnitude	Time in seconds				
	0.0 < 0.2	0.2 < 0.4	0.4 < 0.6	0.6 < 0.8	≥0.8
>80–90%	18.0	2.8	1.2	0.5	2.1
>70–80%	7.7	0.7	0.4	0.2	0.5
>60–70%	3.9	0.6	0.2	0.1	0.2
>50–60%	2.3	0.4	0.1	0.1	0.1
>40–50%	1.4	0.2	0.1	0.1	0.1
>30–40%	1.0	0.2	0.1	0.0	0.1
>20–30%	0.4	0.1	0.1	0.0	0.0
>10–20%	0.4	0.1	0.1	0.0	0.1
0–10%	1.0	0.3	0.1	0.0	2.1

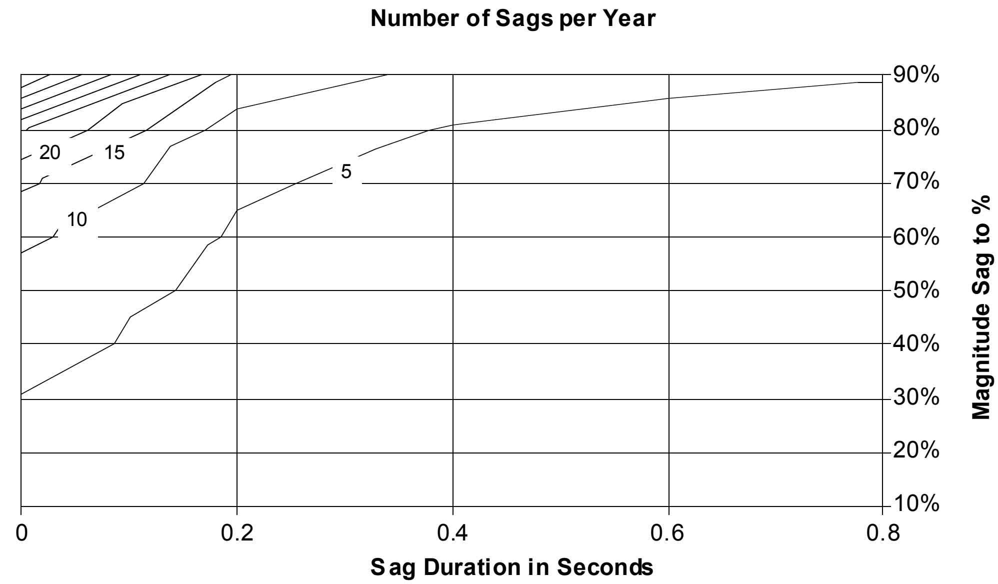
Table B.3—Sum of events worse than or equal to magnitude and duration

Magnitude	Time in seconds				
	0	0.2	0.4	0.6	≥0.8
90%	49.9	13.9	8.4	6.1	5.2
80%	25.4	7.4	4.7	3.6	3.1
70%	15.8	5.5	3.6	2.9	2.6
60%	10.9	4.5	3.1	2.6	2.4
50%	8.0	3.8	2.9	2.5	2.3
40%	6.2	3.4	2.7	2.3	2.3
30%	4.9	3.1	2.6	2.3	2.2
20%	4.2	2.8	2.4	2.2	2.2
10%	3.5	2.5	2.2	2.1	2.1

B.4 Facility performance

The facility electrical system stands between the electric utility system and the process equipment. Although most voltage sags originate on the utility system, the normal voltage operating range at the process can make the difference between ride through and disruption. The IEEE Red Book (IEEE Std 141-1993 [B13]), Buff Book (IEEE Std 242-1986 [B14]), and White Book (IEEE Std 602-1986 [B16]) provide detailed facility electrical design guidelines.

The higher the facility operating voltage within the normal range, the greater the sag capability. Stated another way, the greater the operating voltage, the more energy stored in the component power supplies. The energy stored in the power supply capacitor varies with the square of the voltage. An electronic device experiencing an interruption while operating at 120 V will ride through for a longer period of time than one operating at 112 V. The facility distribution should be operated at the upper end of the normal operating range. (Preferred voltage operating ranges are provided in ANSI C84.1-1995 [B6].)



Example data: Not intended to represent typical performance.

Figure B.4—Average sags per year for EPRI Distribution System Power Quality Project sites from 1 June 1993 to 1 June 1995

The reason the nominal voltage rating is greater than the equipment rating is to allow for voltage drop within the facility electrical distribution network. The design should allow for a 5% voltage drop to the equipment. Excessive voltage drop forces the equipment to operate at reduced voltage with diminished sag capability. Since equipment performance is specified at nominal voltage, lower voltage may cause higher operating temperatures, reduced speed, reduced torque, etc. Transformer taps provide an inexpensive means to adjust the voltage operating range to compensate for voltage drop.

The winding configuration of the facility transformers affects the sag magnitude. For a single-phase ground fault on the utility, the resulting sag magnitude inside the facility depends on the number and sequence of delta wye transformations. Zero volts on one of the incoming phases becomes 33% on the transformer secondary (58% for neutral connected loads). Other three-phase transformers and configurations will produce different internal sags for the same incoming sag.

Large motor starts within the facility can cause voltage sags severe enough to disrupt sensitive equipment. Such loads as air compressors and pumps in industrial facilities or chillers and fans in office buildings are examples. The starting of large motors should be analyzed to assure the associated voltage sags do not disrupt equipment or cause flicker problems.

The above measures provide an additional margin for voltage sag capability. For example, a sag where the voltage momentarily drops to 50% will disrupt equipment regardless of whether these measures were applied. However, most sags occur in the 70% to 90% voltage range, which coincides with sag thresholds of many types of equipment. Therefore, the above measures can significantly reduce sag related disruptions per year at a facility.

Annex C

(informative)

Equipment performance

C.1 Introduction

This annex is intended as an overview of industrial and commercial equipment practices as related to power quality, specifically focusing on voltage sags.

To cover the wide variety of applications, the most common types of problems, equipment, and configurations are discussed in this annex. It is not intended to be a comprehensive description of electronic process equipment, and generalizations will be made without repeated qualifications. A detailed study of any application is always recommended during application design. Application needs, local codes, etc., will determine final equipment specifications and installation practices.

C.2 Obtaining equipment voltage sag information

The best source for voltage sag information is the equipment manufacturer. Additionally, some independent sources, such as the Electric Power Research Institute (EPRI), have tested and collected data on various devices under voltage sag conditions.

If necessary the user can collect data on equipment performance. One approach would be to obtain equipment meant to execute testing to IEC 61000-4-11 (1994). This standard provides a method to test equipment susceptibility to specific voltage sag durations and magnitudes.

Figure C.1 shows a generalized test setup for evaluating voltage sag performance of the equipment under test (EUT). If the equipment requires three-phase input, the equipment should be capable of providing coordinated interruption of all three phases. Phase-to-phase imbalance can be simulated by suitable adjustment of the sag voltage source in a three-phase test setup. The source selection switch is an electronic switch that may be as simple as a solid-state relay or a more sophisticated three-phase transistor scheme. The EUT can be sensitive to the voltage phase shift during the sag and the point of initiation of the sag. These add two new dimensions to the voltage sag parameters (in addition to magnitude and duration) that are not typically available in the sag environment data. Therefore, for compatibility evaluation, it is recommended that phase shift and point of initiation not be considered. For the test evaluation, the sag should be switched in and out during the voltage zero crossing.

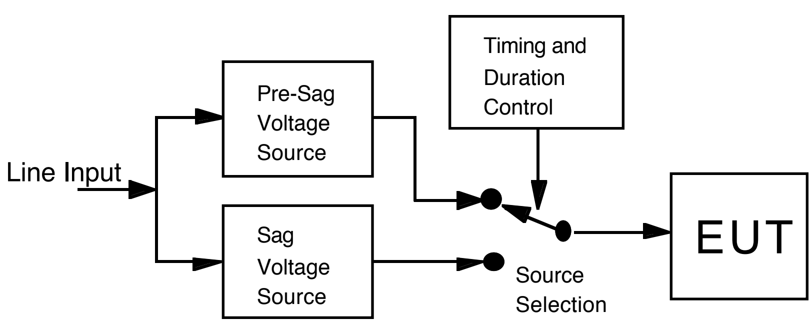


Figure C.1—Voltage sag test setup

C.3 General electronic equipment installation guidelines

C.3.1 Control power

C.3.1.1 Distribution

Intra-plant voltage drops/variations between the service equipment and the sensitive equipment may cause difficulties for equipment. A relatively inexpensive means, such as raising the distribution transformer tap setting, could provide the needed margin to improve performance of an otherwise troublesome piece of equipment.

C.3.1.2 Control or distribution transformer

In Figure C.2 the voltage waveform on the left represents the classic sine wave. However, the flattened waveform on the right is the more typical waveform seen on most feeder circuits. The peak depression is due to the capacitive input filtering done on most electronic equipment such as computers, copiers, faxes, programmable logic controllers (PLCs) or adjustable speed drives (ASDs). In general these only draw current from the line during a small period around the line peak. This effect will not cause a large variation in the rms voltage monitored.

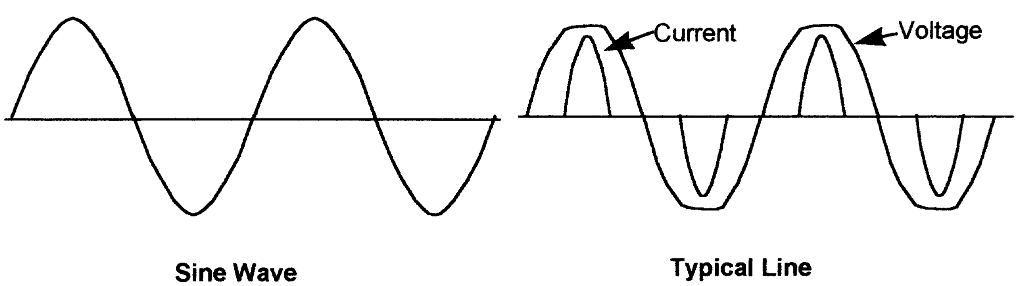


Figure C.2—Typical line wave shape

Since most electronic equipment achieves its voltage sag performance by capacitive energy based on the peak sine wave value, the effect can be multiplied. For instance, a peak depression of 5–10% will manifest itself as only a 1% rms depression. However, this translates into a 10–20% loss in energy storage capability, thus voltage sag performance, of the affected equipment.

Due to this peak loading, a 2.5:1 factor should be used in calculating an appropriate distribution or control transformer to take the peak level of current drawn into account.

C.4 Energy storage in electronic equipment

Most electronic equipment gains its voltage sag performance by capacitive energy based on the peak sine wave value. This is because capacitance is the most cost/volume effective energy storage mechanism. Figure C.3 shows a typical power supply for a computer, copier, fax or PLC and a typical voltage-fed pulse-width modulation (PWM) ASD. The dc bus capacitance in Figure C.3 provides the means for energy storage in a switching power supply and an ASD. Line peak flattening has serious effects on energy storage, as discussed previously. Distribution, line isolation, and control transformers exacerbate the problem due to their reflected impedance and accompanying line flattening.

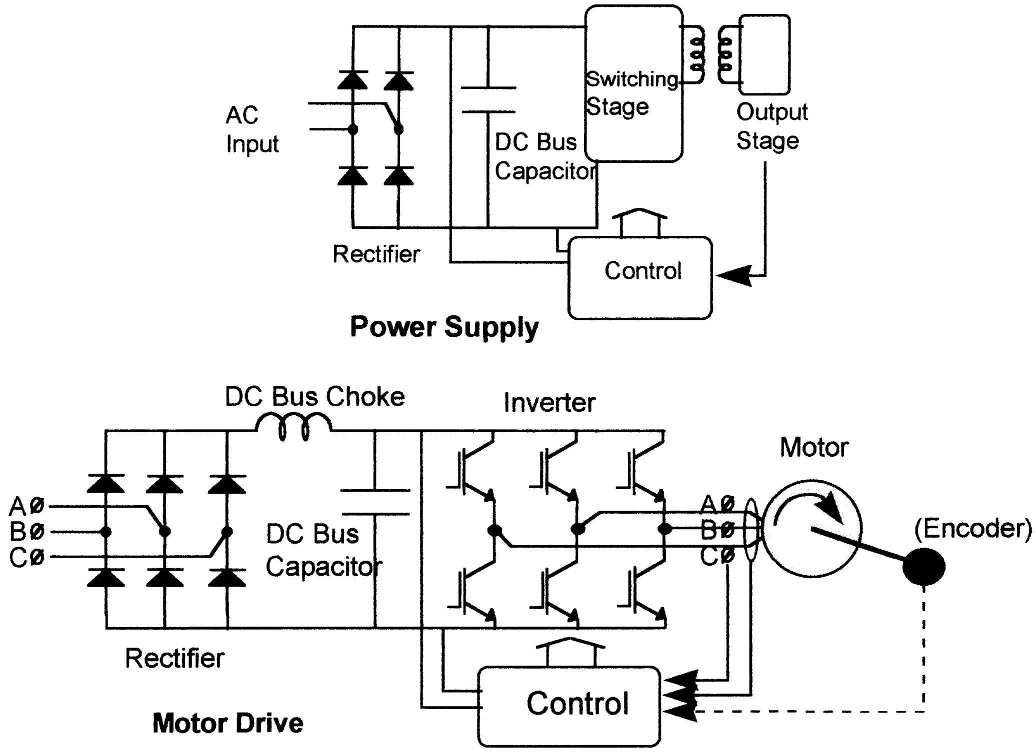


Figure C.3—Diagram of switched mode power supply and ASD

Figure C.4 shows the relative voltage sag or drop characteristic of an electronic equipment power supply based on input voltage before the “event” and the supply loading. As can be seen, there is a dramatic effect based on the precondition of the line before the “event” took place. These same effects are generally true for ASDs, copiers, fax machines, and instrumentation. Loading and operating voltage should be considered.

C.5 Protection

Most electronic equipment incorporates undervoltage shutdown. This protective mechanism generates a shutdown signal when the ac line voltage drops below the equipment’s lower voltage limit. For computers it may prevent invalid data from being stored in memory. For ASDs, it may act to guard against excessive current in line rectifiers.

C.6 Example voltage sag susceptibilities

Figures C.5 through C.10 are examples of the range of sag performance for PLCs, PLC input devices, ASDs, electromechanical relays, starters, and personal computers. These should not be considered typical for these types of devices but only a sample of what is available.

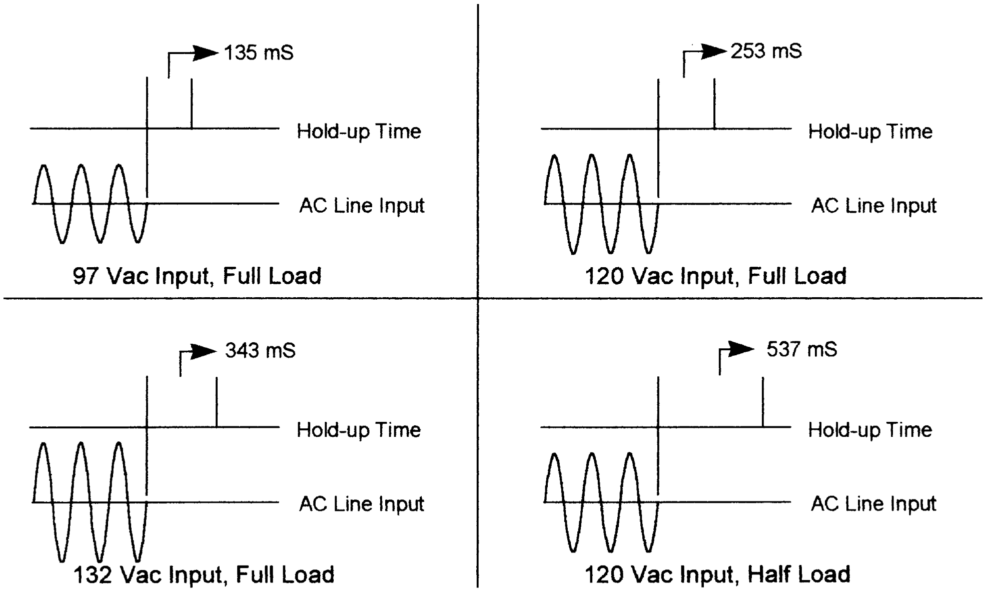
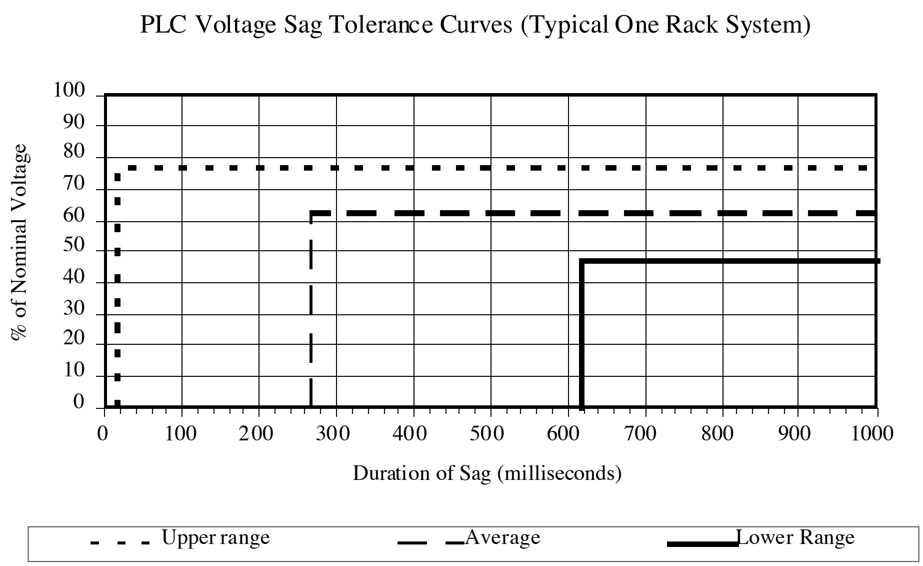
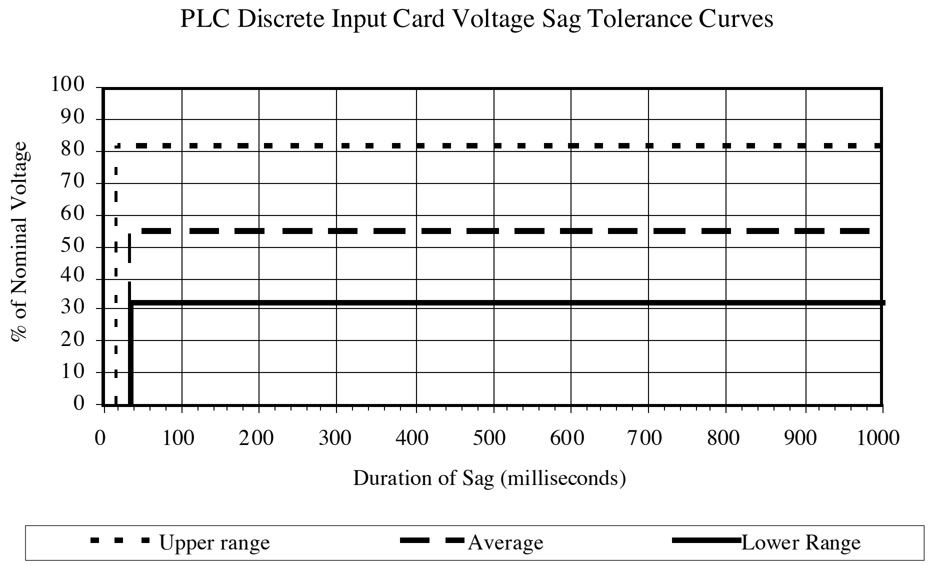


Figure C.4—Effect of load and operating voltage on hold-up time



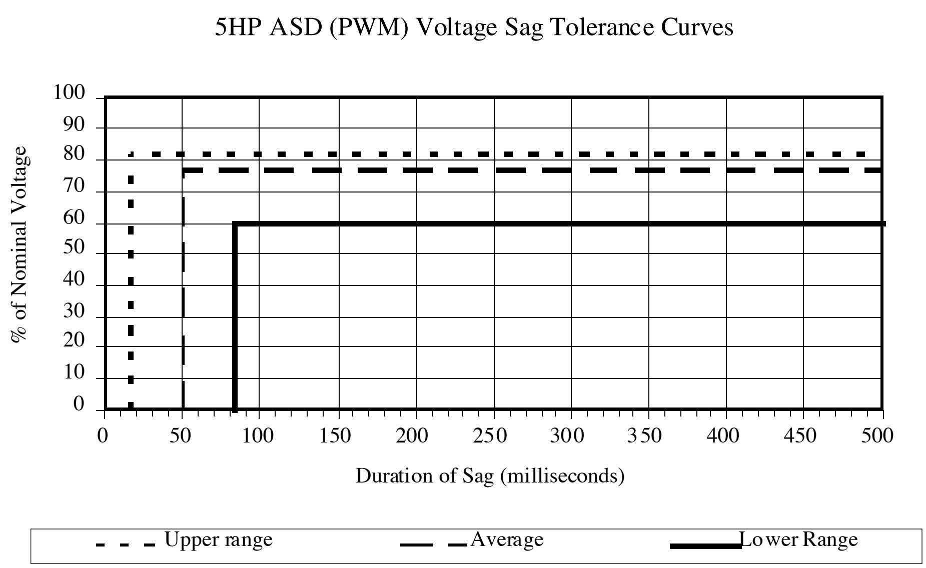
Example data: Not intended to represent typical performance.

Figure C.5—Example of the range of PLC sag tolerances



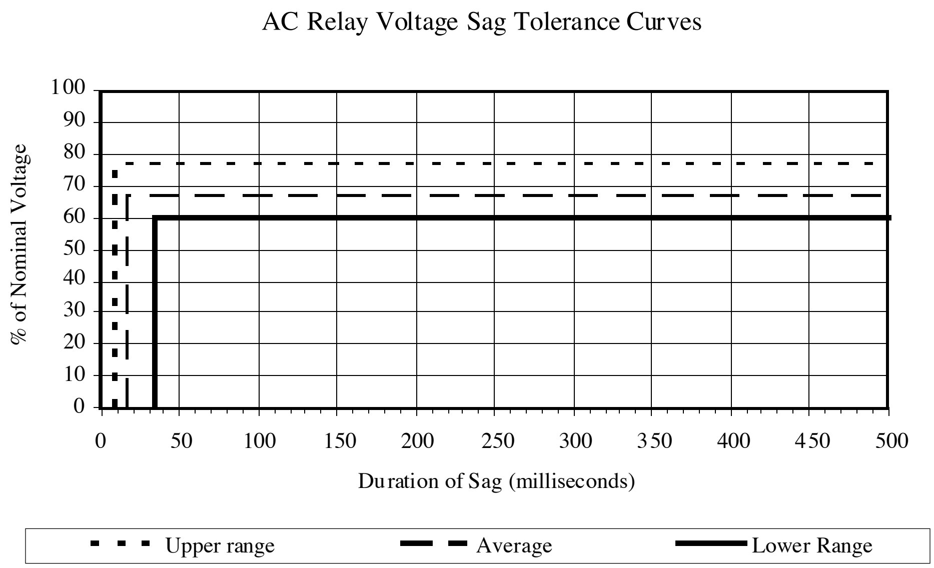
Example data: Not intended to represent typical performance.

Figure C.6—Example of the range of PLC input card sag tolerances



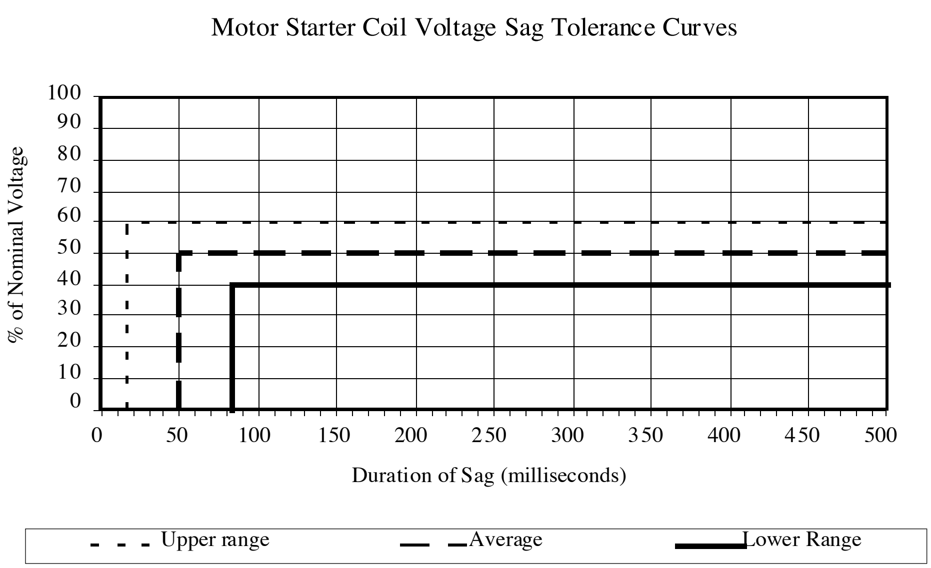
Example data: Not intended to represent typical performance.

Figure C.7—Example of the range of ASD sag tolerances



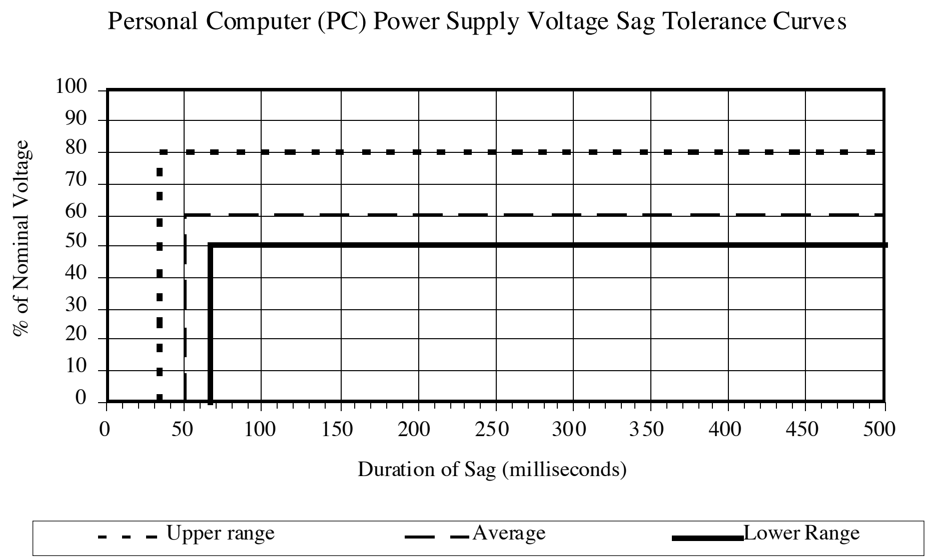
Example data: Not intended to represent typical performance.

Figure C.8—Example of the range of control relay sag tolerances



Example data: Not intended to represent typical performance.

Figure C.9—Example of the range of motor starter sag tolerances



Example data: Not intended to represent typical performance.

Figure C.10—Example of the range of personal computer sag tolerances

Annex D

(normative)

Constructing coordination charts

D.1 Introduction

This annex describes how to create the voltage sag occurrence and equipment susceptibility charts used in Clause 4.

Sag coordination charts show electric supply sag characteristics and utilization equipment response to voltage sags on a single graphical display. The foundation for the display is a two-dimensional grid of sag magnitude on the vertical axis and sag duration on the horizontal axis. A family of diagonal contour lines shows the electric supply sag characteristics. Each contour line represents a number of sags per year.

An equipment line on the same chart shows equipment sensitivity to sags. The area below and to the right of the sensitivity line shows the disruption region, while the area above and to the left corresponds to sags that will not disrupt the equipment. Equipment sensitivity lines often exhibit a rectangular shape. The penetration of the sensitivity curve knee into the supply contours determines the number of disruptions. Proper use of the sag coordination chart estimates the number of utilization equipment disruptions per unit of time due to voltage sags.

Two data sets are critical for the coordination effort. First, the electric supply sag characteristics should either be known from historical data or from predictive techniques. Second, utilization equipment response to sags should be known either from manufacturer specifications or from performance test data. Both supply and response data sets are necessary to perform this coordination effort.

D.2 Chart generation

The display of supply characteristics requires either historical or predicted sag magnitudes and durations. This data fills magnitude and duration bins in a computer spreadsheet for graphical presentation as contour lines. A very simple example will show the fundamental concepts.

Table D.1 shows a grid of nine sag magnitude ranges in rows and five sag duration ranges in columns. The combination of nine rows and five columns produce a total of 45 magnitude/duration bins. Each measured or predicted sag will have a magnitude and duration that fits in only one of the 45 bins. The magnitude bin is a range of sag voltages expressed as a percentage of nominal. The time bin is a range of sag durations expressed as seconds. Each sag will have associated with it one magnitude and one time bin. The number in each table entry will correspond to the number of sags that have magnitudes and times in the same bins. Interruptions would go into the lower row of bins according to the duration. The number of bins may vary depending on coordination needs for a particular case. However, this selection of 45 bins is reasonably convenient.

For this example, assume each of the 45 bins contains one sag event. This means there are 45 sags per year and the characteristics of each sag fits into a unique bin. The 15 bins in the lower-right corner have bold italic highlighting to promote understanding as this example continues.

Table D.2 shows the cumulative number of sag events that are worse than or equal to each bin from Table D.1. “Worse than” means the magnitude is lower and the duration is longer. The row and column headings show only single values instead of ranges. For example, there are 15 sags in the 50% magnitude, 0.4 s entry

Table D.1—Count of events in each bin

Magnitude bin	Time bin in seconds				
	0.0 <0.2	0.2 <0.4	0.4 <0.6	0.6 <0.8	≥0.8
>80–90%	1	1	1	1	1
>70–80%	1	1	1	1	1
>60–70%	1	1	1	1	1
>50–60%	1	1	1	1	1
>40–50%	1	1	***1***	***1***	***1***
>30–40%	1	1	***1***	***1***	***1***
>20–30%	1	1	***1***	***1***	***1***
>10–20%	1	1	***1***	***1***	***1***
0–10%	1	1	***1***	***1***	***1***

of Table D.2. The bold number 15 in Table D.2 is the sum of all 15 individual bold entries in Table D.1. This means 15 sags will have magnitude less than or equal to 50% and a duration longer than 0.4 s.

Table D.2—Sum of events worse than or equal to each magnitude and duration

Magnitude	Time in seconds				
	0.0	0.2	0.4	0.6	0.8
90%	45	36	27	18	9
80%	40	32	24	16	8
70%	35	28	21	14	7
60%	30	24	18	12	6
50%	25	20	**15**	10	5
40%	20	16	12	8	4
30%	15	12	9	6	3
20%	10	8	6	4	2
10%	5	4	3	2	1

The next step converts Table D.2 to a set of contour lines similar to elevation contour lines on a topographic map. Figure D.1 is the contour plot of Table D.2 generated by a computer spreadsheet and graphics program. The diagonal lines from lower left to upper right represent number of sag events per year. Each contour line has a label for number of events. Within the IEEE website, under working group area Electric Power System Compatibility with Electronic Process Equipment, there is a downloadable program that will generate the contour chart from data input to the database. The address of the IEEE website is **http:/stdsbbs.ieee.org**.

Continuing the simple example, the 15-event contour line intersects the 0.4 s axis at the 50% magnitude axis. This means 15 sags will have a 0.4 s or longer duration and have 50% or lower magnitude. The dots on the lower-right corner of Figure D.1 show each of the 15 individual sags. Each dot represents the one sag event in each bin of Table D.2 for this example. There are 15 dots in the rectangular area below and to the right of the contour line. Similarly, the 20-sag contour shows 20 sags worse than or equal to 0.2 s and 50% magnitude. Normally, the dots will not appear on sag coordination charts. Also, the actual sags will be somewhere in the stated range and not directly on the axis.

Linear interpolation between contour lines and axis works reasonably well. For example, about 32 sags will be worse than or equal to 0.2 s and 80% magnitude on Figure D.1, or 25 sags will be worse than about 0.28 s and 70% magnitude.

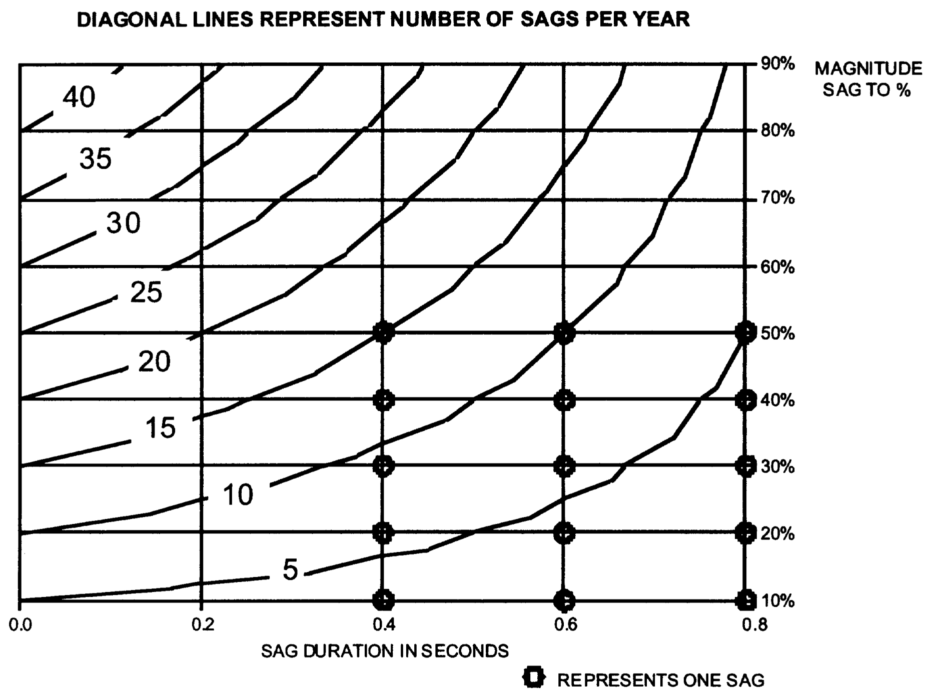


Figure D.1—Supply sag performance contours and partial mapping of individual points

D.3 Adding utilization equipment sensitivity

D.3.1 Rectangular equipment sensitivity

The sag contour lines work well with rectangular sensitivity curves. Figure D.2 overlays the utilization equipment sensitivity on the sag contour lines. The sensitivity curve is typically rectangular or may be approximated with several rectangles. The shaded region shows what sags will cause disruption. The intersection of the rectangular sensitivity curve knee and the contour line determines the number of disruption events from sags. Continuing the simple example on Figure D.2, the knee of the curve intersects the 15-sag contour line. This means there will be 15 process disruptions per year.

D.3.2 Nonrectangular sensitivity

The previous analysis assumes the equipment sensitivity has a rectangular shape. Nonrectangular sensitivity curves require a little more effort. Consider Figure D.3. The equipment sensitivity is approximated by a shape with two knees. The disruption region is the combination of all three shaded rectangular areas A, B, and C. Knee #1 intersects the 20 sag line at 0.2 s and 50% magnitude. Knee #2 of the sensitivity curve intersects at about 24 sags using linear interpolation. A third “knee” for area C intersects the 15-sag contour.

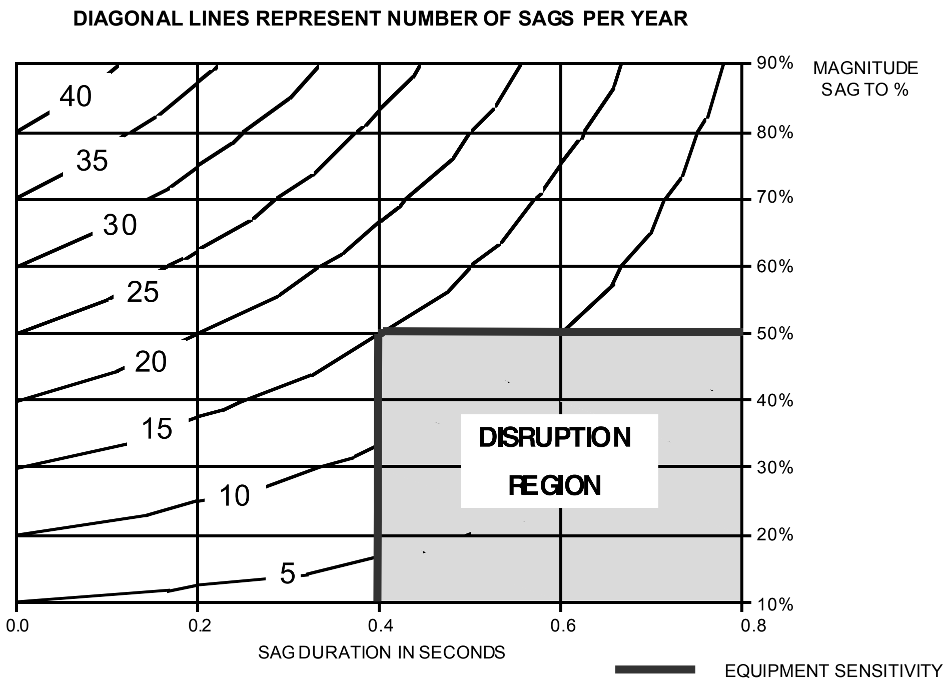


Figure D.2—Supply sag performance contours and equipment sensitivity

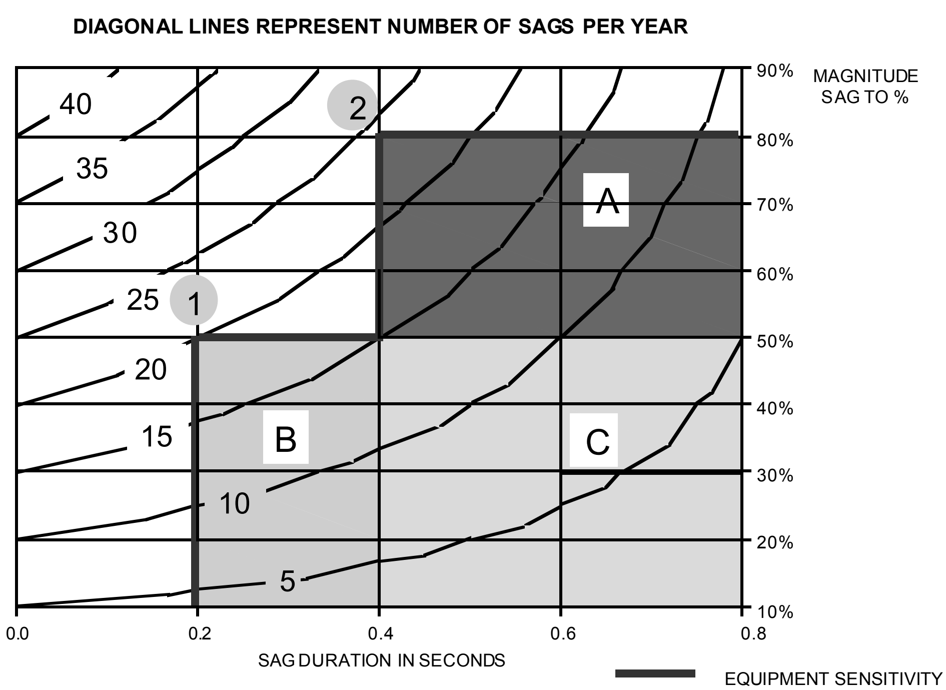


Figure D.3—Approximation of nonrectangular sensitivity curve

Rectangular approximation solves the problem. Knee #1 is rectangular consisting of area B and area C. It contains 20 sags. Likewise, area A and area C represent a rectangular sensitivity of all sags for knee #2 containing 24 sags. Notice that area C is shared by both knees. Simply adding the sags for knee #1 and knee #2 would overestimate the total sags by double counting area C. The mathematics to avoid double counting is shown below.

$$\text{Total number of sags} = \text{area A} + \text{area B} + \text{area C}. \tag{1}$$

For knee #1, there are 20 sags. Therefore,

$$B + C = 20 \tag{2}$$

Solving for B,

$$B = 20 - C \tag{3}$$

For knee #2, interpolation is required. Interpolation gives about 24 sags. Therefore,

$$A + C = 24 \tag{4}$$

Solving for A,

$$A = 24 - C \tag{5}$$

Careful examination of area C shows it intersects the 15 sag contour line. This means area C represents 15 sags. Knowing C = 15 sags, calculate area A and area B.

$$A = 24 - 15 = 9 \tag{6}$$

$$B = 20 - 15 = 5 \tag{7}$$

Substituting in (1), the total number of sags

$$A + B + C = 9 + 5 + 15 = 29 \text{ disrupting sags} \tag{8}$$

Thus, the sag coordination chart predicts 29 disruptions per year for this nonrectangular shape equipment sensitivity. A simple counting effort on Figure D.3 (as with the dots in Figure D.1) confirms the 29 disruptions. (It is also possible to overlay the equipment sensitivity over Table D.1 and total the sags for a similar result.)

Annex E

(informative)

Example

E.1 Objective

In this example, the compatibility methodology will be applied to a fictitious fabric web system. After the data required for down time costs, sag environment, and equipment performance are collected, a financial analysis is performed to evaluate a project to reduce the cost of compatibility.

E.2 Gathering information

Figure E.1 shows a contour plot of the annual expected rates of interruptions and sags for the facility. The electric utility provided historical sag data from a substation power quality monitor. The facility electrical distribution system operates near nominal 480 V. No adjustment of the utility data was performed.

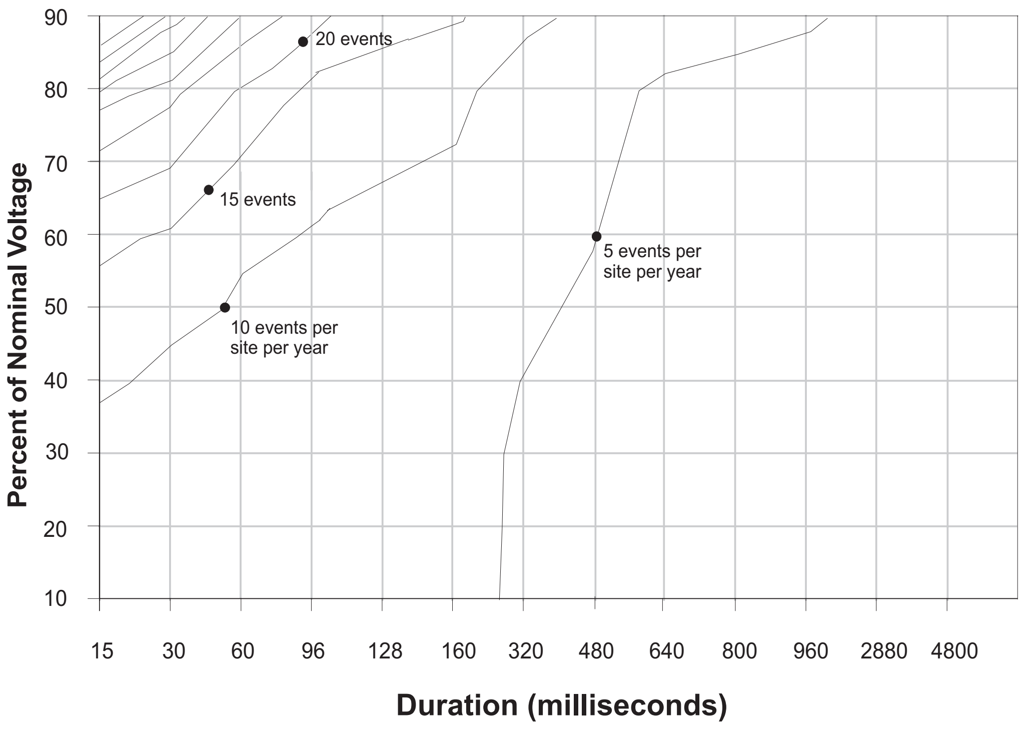


Figure E.1—Voltage sag and interruption contour chart

Figure E.2 shows the sag performance of the individual components of the process. This data was obtained from the equipment suppliers and was required in the purchase specification. There are several components in the system, and they are all shown separately on the chart. Showing them separately allows the overall system susceptibility to be adjusted by replacing components.

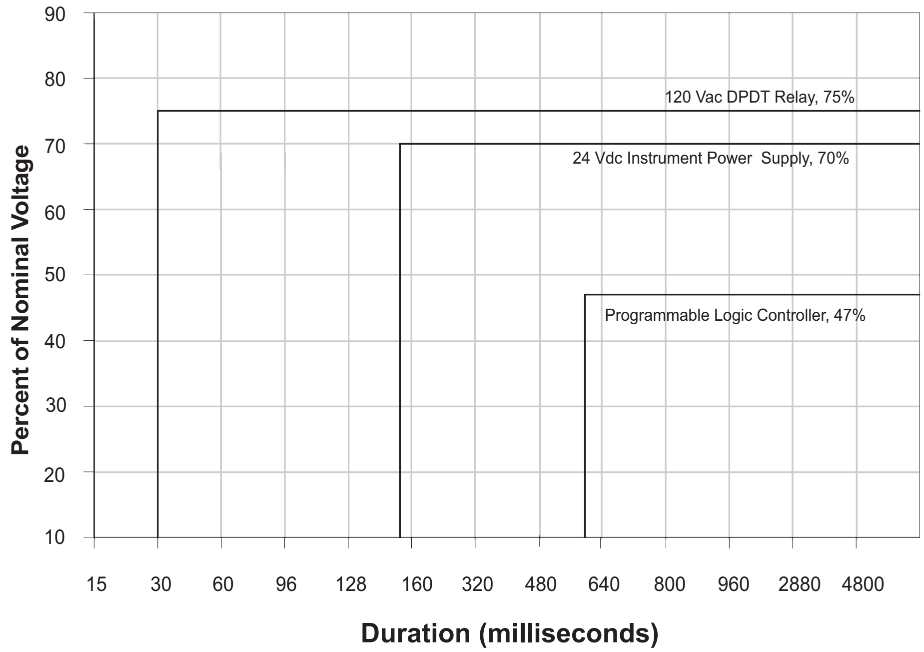


Figure E.2—Sag susceptibilities of process components

Figure E.3 is the coordination chart and is the result of overlaying Figures E.1 and E.2. This chart will yield the typical number of events per year in which voltage sags will disrupt the process. The component with the sensitivity knee in the most upper left hand portion of the figure will define the sensitivity for the process. In this case, the most sensitive component is the double-pole double-throw (DPDT) relay and the knee is in the 20 to 25 times per year band. Interpolating between the contours, it appears the number of disruptions predicted by the coordination chart is 23 per year.

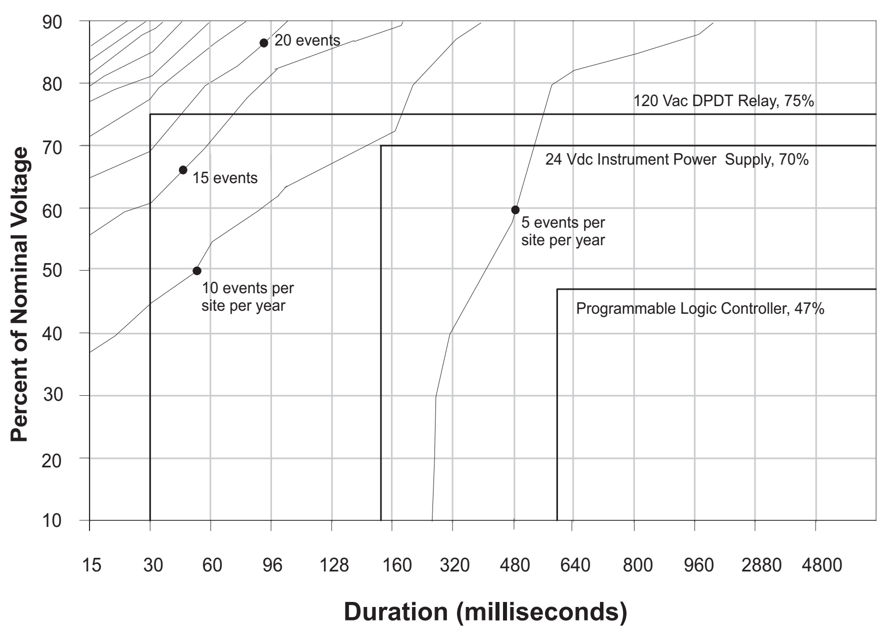


Figure E.3—Overlay of sag environment and component susceptibilities

Notice the upper-left portion of the figure has a large gradient of sag events. If the relay were changed or replaced so that the dc instrument power supply became the most sensitive device, the number of predicted disruptive events would be reduced to about nine. At this point, some options may be brainstormed to improve the sag environment and decrease the equipment sensitivity. Does the electric utility offer any options to decrease the number of sags? Can a sag ride-through device be provided for the plant? Are there other components available that are less sensitive? Can the process logic be changed so that the end result is less sensitive? The approximate cost of these options should be found, so that they can be evaluated in the financial analysis portion.

The cost of disruption for this example is shown in Figure E.4. It was determined that $1200 (U.S. dollars) was lost in wages paid to idle workers while maintenance brought the equipment back in operation. The parts damaged during the disruption cost about $8000 and usually have to be delivered on an emergency basis at an additional $500 charge. Another $100 is spent on miscellaneous repair materials. The problem occurs most often during the day shift so maintenance personnel are usually available to perform the repairs. Therefore, there is no additional cost for repair labor. The plant operates at full production, hence there is no opportunity to recover lost production. The disruption in production causes $4000 in lost profit from product that cannot be sold. It also generates $500 in scrap. Their customer's inventory is often depleted and his production is stopped. Under terms of the contract with the customer, the business is fined $200 for the delay.

Each disruption costs about $14 300. Assume that of the 23 disruptive sag events per year, 18 occur when they are in production. That means the annual cost of compatibility is $257 400. There may be some things they could do in their operations to lessen the cost, such as maintaining a finished parts inventory that will reduce the lost profits and eliminate the customer penalty.

E.3 Compatibility evaluation

Two projects to reduce the cost of voltage sags are considered. The first approach is to reduce the sensitivity of the web controls. The second is to install a sag ride-through device to protect the plant process loads. The former requires diligence in assuring that other sensitive components in the process have not been overlooked or are not added later. The latter does not require policing of individual component sensitivities but does create a more complex power distribution system.

The 120 V DPDT relay is the most sensitive component shown in Figure E.3, causing 23 disruptions per year. The equipment manufacturer is willing to replace the relay with a solid-state version for an additional $8000. The solid-state version would operate as long as the 24 V instrument power supply was functional. The sensitivity of the power supply corresponds to nine events per year from Figure E.3. If the plant is operating for only seven of the nine sags, then the relay replacement has saved the plant from 11 disruptions per year. At $14 300 per disruption, the annual benefit of the change is $157 300. The financial analysis is shown in Figure E.5. The payback is so overwhelming that this process may be continued with the next most sensitive component.

Another approach is to improve the sag environment presented to the process equipment. This method becomes practical if component changes are not possible or if the costs of such replacements become substantial.

In this example to minimize the losses to the business, a voltage sag ride-through energy storage device is evaluated that would provide bumpless voltage for up to 30 s for a complete interruption. It would be trailer-mounted next to the facility and protect the plant process loads. The required 400 kVA unit would cost $160 000 to purchase and require another $50 000 to install. Annual maintenance cost for the device is estimated at $10 000, and additional electrical losses will cost $2400 per year.

Of the projected 18 sag events per year, six of them, based on past performance, are interruptions that are greater than 30 s in duration. The ride-through device will not protect the plant for these events. Therefore, on average, the device is projected to save the plant from 12 disruptions at $14 300 each or $171 600 per year.

Downtime Related
- Increased buffer inventories (value of incremental inventories · WACC)
- Lost work
  - Idled labor
    - Disrupted process (man-h · unloaded labor rate) $1200
    - Starved process (man-h · unloaded labor rate)
  - Lost production
    - Lost profits (unbuilt product · profit margin) $4000
    - Makeup production
      - Overtime labor + premium
      - Overtime operating cost
      - Expedited shipping premiums
      - Late delivery fee
  - Cost to repair damaged equipment
    - Repair labor
    - Repair supplies $100
    - Repair parts $8000
    - Cost of replacement part availability
      - Expedited shipping of parts $500
      - or
      - Carrying cost of parts
    - Cost of recovery
    - Secondary equipment failures (treat as repairs)
    - Recovery labor inefficiency

Product quality
- Replacement value of scrap (BOM value + labor value $500
- Blemished product lost profit margin
- Rework cost
  - Labor
  - Manufacturing supplies
  - Replacement parts

Miscellaneous
- Customer's dissatisfaction
  - Lost business
  - Avoided customers due to longer lead time
- Fines and Penalties $200
- Other

TOTAL $14 300

Figure E.4—Cost of disruption tabulation (U.S. dollars)

Investment		Return	
One-time capital outlay	$8000	Annual benefit	$157 300
+ Installation	$0	– Ongoing annual expense	$0
Net investment	$8000	Net annual return	$157 300

Payback = 0.6 months = ($8000/$157 300) · 12

Figure E.5—Financial analysis for the relay replacement

This information is entered in the financial analysis chart from Figure 2 and is shown in Figure E.6. The simple payback is just under 16 months, which is sufficiently favorable that a more detailed financial analysis may not be required. Most businesses would consider this a very compelling cost-saving project.

Investment		**Return**	
One-time capital outlay	$160 000	Annual benefit	$171 600
+		–	
Installation	$50 000	Ongoing annual expense	$12 400
Net investment	$211 000	Net annual return	$159 200

Payback = 15.9 months = ($211 000/$159 200) · 12

Figure E.6—Financial analysis for voltage sag ride-through device

Annex F

(informative)

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