LOAD SHEDDING FOR UTILITY AND INDUSTRIAL POWER SYSTEM RELIABILITY

Power systems are designed and operated so that for any normal system condition, including a defined set of contingency conditions, there is adequate generating and transmission capacities to meet load requirements. However, there are economic limits on the excess capacity designed into a system and the contingency outages under which a system may be designed to operate satisfactorily. For those rare conditions where the system's capability is exceeded, there are usually processes in place to automatically monitor a power system's loading levels and reduce loading when required. The load shed processes automatically sense overload conditions, then shed enough load to relieve the overloaded equipment before there is loss of generation, line tripping, equipment damage, or a chaotic random shutdown of the system.

To organize the discussion of load shedding, consider that the topic may be differentiated according to the following lists.

- Overloads may be differentiated by what is overloaded:
  1) Those in which there is a real power shortage and in which the prime mover torque cannot meet the load torque and the generation begins to decelerate.
  2) Those in which there is a reactive power shortage. This is manifested as voltage drops in line and transformer reactances that prevent power delivery to loads.
- The overload may also be differentiated by magnitude and suddenness:
  1) Those in which the condition arises and progresses rapidly, and in which the condition cannot be sustained or withstood and for which a high speed automated response is required.
  2) Those in which the condition arises and progresses slowly, and in which the condition can be sustained or withstood for a short period. This condition allows for manual response by operators.
- The overload may be differentiated by the method that is used to detect and respond to the condition:
  1) Dispersed frequency monitoring.
  2) Dispersed voltage monitoring.
  3) Utility Scale SCADA System Configuration Monitoring
  4) Industrial Scale System Configuration Monitoring
  5) Local equipment overload monitoring

The material to follow stresss analysis of item 1 in each of the above lists, but every item in the lists is discussed in part. Following the analysis is review of load shed implementation strategies.

ANALYSIS OF SYSTEM DURING AN OVERLOAD CONDITION

Prior to reviewing methods of overload detection and load shedding it may be helpful to review what might be considered a representative system disturbance, provide some general ideas about what occurs as a system disturbance progresses, and perform some basic analysis of what occurs during a system overload. While an accurate modeling requires a transient stability program, some understanding of the event is available on a more basic level. The more basic analysis covered below includes:

1) Simple frequency decay rate analysis using system inertial energy and accelerating/decelerating power.
2) Watt and VAR transfer limitations of transmission lines.
3) Load variations under changing voltage and frequency, including load dropout due to undervoltage conditions.
4) Generator response, including the governor and voltage regulator, and inherent output changes under frequency deviations.
5) Limitations on allowable electrical frequencies at generators and loads.

Example System Disturbance

After a system disturbance has allowed the creation of an islanding condition, if the generation is less than the applied load, it is intuitive that the generator(s) slows down. When slowing down, the average frequency of the system does not decay instantly but the stored rotational energy of the generator is absorbed to make up for insufficient prime mover torque. If the frequency decay is slow enough, generator governor response comes into play to reduce the torque error The role of load shed relaying is to reduce the loading to a level that gives the governors time to respond.

A system overload results in locally high currents, locally depressed voltages, and, in some cases, a system frequency depression. It is intuitive that, during heavy loading, voltages in a system tend to be depressed, but in the presence of high speed automatic voltage regulation the voltage depression may be short term or may not occur, depending on the suddenness of the overload condition and remoteness from voltage regulating equipment. Decreasing voltage may cause increased current and, hence, increased VAR loading by transmission lines.

References [1], [2], [3], and [4] provide sample system disturbances, but there are numerous comparable sources. The following example disturbance is drawn in part from these sources and other comparable sources. It is an attempt to show the various aspects of an overload condition and the protection practices that could be used to detect and respond to the condition.

Examine the system shown in Figure 1. Imagine the following scenario that shows several chances for a load shed system to prevent a system collapse and shows some aspects of how an apparently stable system may actually be slowly progressing toward a system collapse.

At first it appears that buses D, E, F, and G are too well tied to the system grid (represented by A, B and C) for an islanding condition to occur. Suppose that buses D, E, F, and G are drawing power from the rest of the world and that loading overall is quite heavy at this time. Now suppose lines A-D and B-D are on a common transmission tower right of way and for some reason a single event (e.g., a tower failure) took both lines out of service. To some extent this is almost a triple contingency situation: It assumes the loss of two lines at a time of heavy system loading. But it is a possible scenario that is not beyond the realm of possibility. Suppose that line C-E is now overloaded, and that voltage in the system has decayed. This relieves loading to some extent. Suppose generator E is small in relation to the local loading and that generator E tries to support voltage and its field began to supply VARs beyond its long-term capacity.

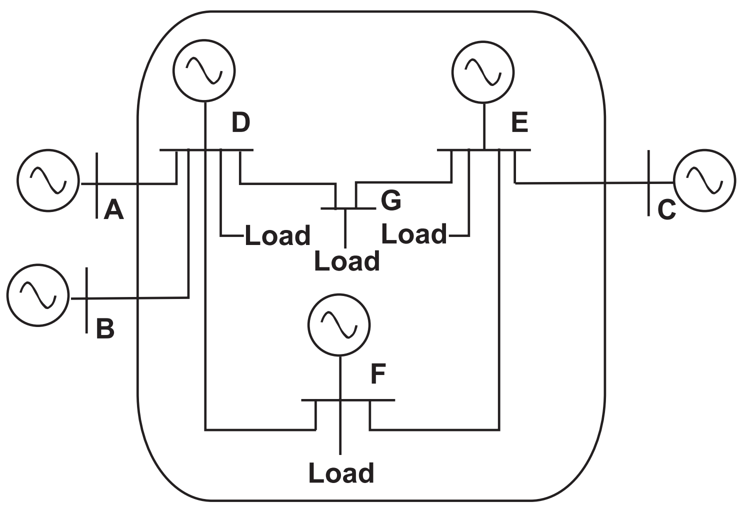


Figure 1: Example System

System operators might see the event where lines A-D and B-D were lost and, from their remote location, think the system was surviving the event but with moderately depressed voltage. However, one minute after the event, tap changers throughout the system start to correct for low voltage and the system load starts to rise. Two minutes after the event the field excitation limiter at generator D forces the field to back down and voltage at the loads falls again. Then one minute later tap changers start to raise load voltage again and load again rises. Operators might see the heavy loading on line C-E and become concerned but decide to accept the condition. If they could monitor the generation and realize that the excitation limiters had kicked in, they might even be more concerned. But this is approaching information overload and possibly only a smart SCADA system could identify that the system is on the verge of voltage collapse.

Prior to voltage collapse, another unforeseen event occurs. The protective relaying on the heavily overloaded line C-E trips due to load encroachment that looks like a zone 3 distance fault. The system consisting of buses D, E, F, and G has islanded with insufficient generation to support its load, several minutes after the initial event. At this point frequency based load shedding may be the only method that can stop the imminent collapse of the island.

This process shows all the means of load shedding that could have been used in the process:

1) The last resort, underfrequency relaying, was the final defense against island collapse once the island was created. The condition could have been caught earlier.
2) Undervoltage relaying could feasibly have detected a condition and shed load.
3) Before the event ever occurred studies by a System Planning group could have been performed that could have shown that if the double line outage condition occurs during heavy loading there would be risk of the system collapse. System operators aware of the condition could have shed load manually.
4) Similarly, a properly programmed SCADA system feasibly could have recognized the condition and flagged an operator that load needed to be shed or even performed the load shedding automatically.

Figure 2 shows what may be considered a representative picture of what occurs with respect to time after the three generators lose synchronism with the rest of the power system. Assume that the pre-event loading levels there is a 20% shortage of generation in the area and a system inertia constant (H) of 6. (This is on the high side of typical H constants for power systems, but an equivalent graph would be obtained with an H of 3 and an overload of 10%.) As is revealed in later analysis, this results in an approximate average frequency decay of 1 Hz/sec. While this may be the average frequency decline, during the event the generators oscillates with respect to one another and the instantaneous frequency at a given bus deviates from the average frequency.

Assuming that there are frequency relays at each bus set to trip at 58 Hz, there is a load shed event a bit greater than the generation shortage at about 2 seconds into the event and after the load shedding the frequency starts to recover. Figure 2 assumes a constant mismatch of load and generation. For this to occur, there must be no governor response, no generator power decay as the turbine slows, and no load dropout due to voltage and frequency decay. The load shed that occurred at 58 Hz will actually occur at different times at each bus. Note bus D, E, and F reached the trip frequency at the respective times of about 1.9, 2.0, and 2.2 seconds.

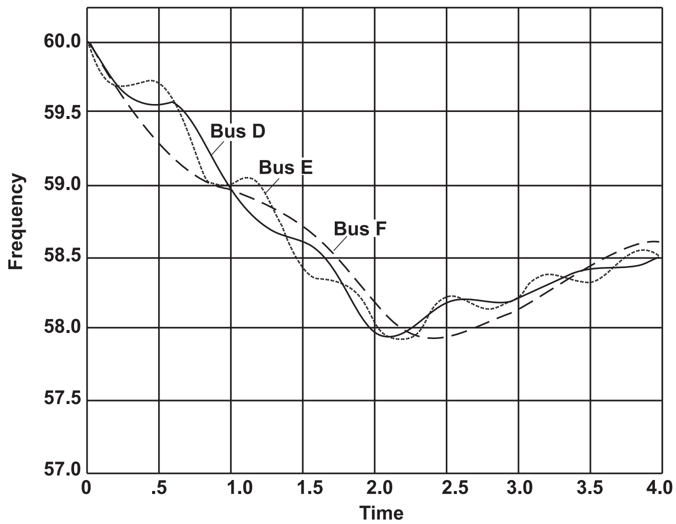


Figure 2: Frequencies in Sample Disturbance

Though the generators generally track together, both the frequency and the rate of change in frequency at each bus varies considerably at any given point in time. At any point in time any one of the generators may be moving faster than the others, and there are times when one generator is actually accelerating even though frequency as a whole is decreasing. The magnitude of the difference of a given generator from the average frequency in this example is about 0.2-0.3 Hz.

If one integrates the generator frequencies with respect to each other one can see that the generators are swinging by nearly 90° with respect to one another immediately after the separation. For example, compare the trace for generators D and F. In the time from about 0.2 to 1.0 seconds, the net area between the two curves is about equal to a little less than one square on the graph. Each square is equal to about 90 degrees of separation (0.5 Hz difference for 0.5 seconds = 180°/sec x 0.5sec = 90°). In other words, during the initial one second after the event began, the shaft of generator D and F separated from one another by about 90° and then continued to oscillate with respect to one another. Depending on the relative position of the generators D and F at the start of the event, it appears from this analysis that the generation at bus D and F were on the verge of pulling out of synchronism with each other.

Simplified Frequency Analysis

For the initial period of the overload, if we can assume a constant load, constant generation power output, and no oscillations of frequency between the generators, the response of the system is simply the physics behind the transfer of a lumped equivalent stored rotational energy in the system, to the loads in the system. The analysis is instructive in envisioning the system response during an overload condition and provides a conservative picture of how fast an underfrequency relay must respond to save a system from collapse during an overload condition. Some references that review this material are [3], [4], [5], [6], and [7]. We can also expand on this to show the oscillations that occur between generators during an upset condition.

Average Frequency Decay Using System Stored Energy and Load and Generation Mismatch

There is stored energy in the motion of a generator. The equation that relates rotational speed to rotational energy is:

$$Stored\ Kinetic\ Energy = \frac{1}{2} J\omega^2 \quad \text{W·s} \qquad \text{Eq. 1}$$

where

$$J = \text{moment of inertia in kg} \cdot \text{m}^2$$
$$\omega = \text{mechanical rotational speed in radians/second}$$
$$= \frac{2\pi\, \text{RPM}_{\text{mechanical}}}{60}$$

If the torque produced by a machine's prime mover does not match the torque produced by the generator magnetic fields (and losses due to friction and windage), the machine will accelerate or decelerate. A basic equation relating torque to acceleration is:

$$T_a = J\frac{d\omega}{dt} \qquad \text{N} \cdot \text{m} \qquad \text{Eq. 2}$$

Dividing (1) by generator VA rating yields

$$\frac{Stored\ Kinetic\ Energy}{VA} = \frac{\frac{1}{2} J\omega^2}{VA} \qquad \text{s} \qquad \text{Eq. 3}$$

When ω is at rated frequency, the left side of (3) is commonly referred to as the generator inertial constant, *H*.

H	=	generator inertia constant
	=	The ratio of stored rotational energy in Watt seconds (or typically, MW seconds) of a generator spinning at nominal frequency, divided by generator VA (or MVA).

Or

$$H = \frac{\frac{1}{2} J\omega^2}{VA} \text{ s} \qquad \text{Eq. 4}$$

For a multiple machine system an averaging method is used to measure *H*:

$$H_{net} = \frac{H_1 * MVA_1 + H_2 * MVA_2 + \dots}{MVA_1 + MVA_2 + \cdots} \quad \text{s} \qquad \text{Eq. 5}$$

To be complete, the *H* of the load is included as well. During this deceleration of the system, the inertial energy of the loads will be consumed by the load and, hence, provide some load relief for the generators. The load *H* varies with the type of load; motor loads have some inertia, but resistive loads do not.

Typical *H* constants are given below, but there is some conflict from one source to another of what are typical *H* constants. One reason for the conflict is that newer machines tend to be more lightly built due to the advances in materials technology and manufacturers' computing capabilities. A lighter, newer machine will have lower *H* constants. For example, a modern large steam turbine may have an *H* constant of 3 but a very old one of the same MVA may have an *H* constant of 10. This may be a representative table, however.

Diesel Engine	1-3
Combustion Turbine, simple cycle	2-5
Combustion Turbine, combined cycle	2-7
Steam Turbine	3-10
Hydro	2-5
Load, motor	0.5-3

Table 1: Example H *constants*

Solving (4) for *J*

$$J = \frac{2H \cdot \text{VA}}{\omega^2} \ \text{kg} \cdot \text{m}^2 \qquad \text{Eq. 6}$$

Substituting into (2) yields

$$T_a = \frac{2H \cdot \text{VA}}{\omega^2} \frac{d\omega}{dt} \ \text{N} \cdot \text{m} \qquad \text{Eq. 7}$$

If rated torque is defined as rated VA divided by rated frequency then (7) can be converted into per unit accelerating torque:

$$T_{a,pu} = 2H \frac{d\omega_{pu}}{dt} \quad \text{per unit} \qquad \text{Eq. 8}$$

This can solved for the initial rate of change in frequency:

$$\frac{d\omega_{pu}}{dt} = \frac{T_{a,pu}}{2H} \quad 1/\mathrm{s}^2 \qquad \text{Eq. 9}$$

Unless frequency drifts far from the base frequency we can approximate per unit torque as being the same as per unit power, so T_a may be replaced by P_a. Also, since per unit frequency is the same as per unit ω , we can convert to f_{pu}. Hence (9) becomes:

$$\frac{df_{pu}}{dt} = \frac{P_{a,pu}}{2H} \quad 1/\mathrm{s}^2 \qquad \text{Eq. 10}$$

The significance of (10) is that it may be used to determine the initial rate of change of frequency of the system. The trick is knowing P_a. We have some good idea of what the value of pre-event generation and loading were, so assume that we can use these values to define P_a.

$$P_{a,pu} = \frac{P_{gen} - P_{load}}{P_{gen}} \qquad \text{Eq. 11}$$

Equation (10) can used to create an equation for frequency versus time:

$$f(t) = f_0\left[1 + \left(\frac{P_{a,pu}}{2H}t\right)\right] \qquad \text{Eq. 12}$$

This can be solved for the time that it takes for a decaying system to reach a given frequency:

$$t(f) = \frac{\frac{f}{f_0} - 1}{\frac{P_{a,pu}}{2H}} \qquad \text{Eq. 13}$$

Figure 3 and 4 plot (12) and (13) for various levels of H and various overloads. As noted previously, $H = 6$ may be high for typical systems, but $H = 3$ and $P_a = 0.1$ gives the same result at $H = 6$ and $P_a = 0.2$. The graphs, therefore, may be viewed for other systems fairly easily.

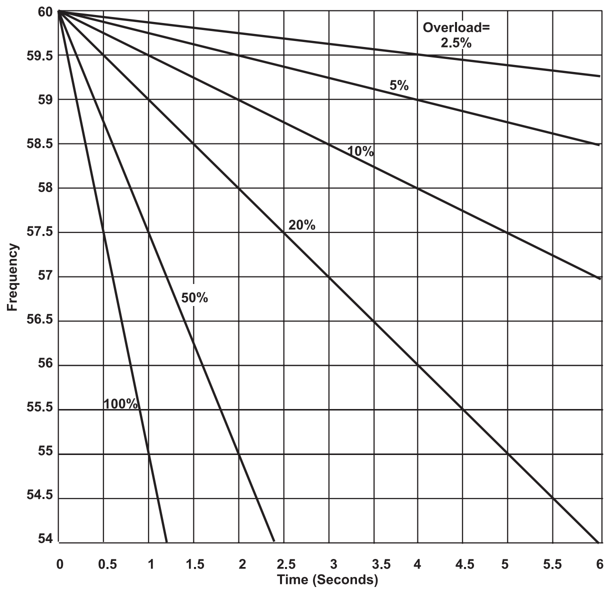


Figure 3a: Simple Analysis Frequency Decay, H=6, Various P_a

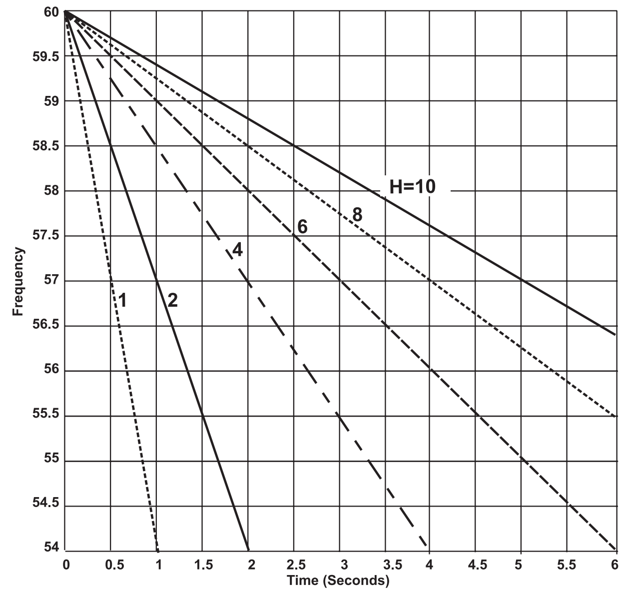


Figure 3b: Simple Analysis Frequency Decay, P_a = 0.2pu, Various H

Instantaneous Local Frequencies

On a moment by moment basis, the frequency measured at a given bus varies considerably from the average frequency of the system. The frequency measured at a given bus is modulated locally by several additional sine waves as the local and remote generators rock back and forth with respect to one another. The frequency of the system at a given bus may be approximately represented by:

$$f_{bus}(t) = f_{nom} + \left(\frac{df}{dt}, sys.avg.\right)t + \left(A \cdot \sin(2\pi\ f_a t + \alpha) + B \cdot \sin(2\pi\ f_b t + \beta) + \ldots\right) \qquad \text{Eq. 14}$$

The values for the modulation frequency, $f_{a,}$ f_b, etc., from a review of the sample disturbances in the references (various studies and samples found throughout [1]-[10] and other locations) take on values of up to 0.2-5 hertz (the farther apart the generation, the lower the frequency, generally), but, of course, higher and lower frequencies can occur. The amplitude of the modulating frequencies, *A, B, etc.*, from the same references falls in the range of less than 0.5 typically, but up to 1 for higher frequency swings.

As an example of this equation, it may be noted that Figure 2 was generated using this equation. Figure 2 was not the output of a transient stability program but a figure created to represent what is found in actual application. Figure 2 was generated by setting:

Generator	A	f_a	α	B	f_b	β
D	0.2	1.10	π	0.03	2.0	0
E	0.2	1.50	π	0	0	0
F	0.3	0.45	π	0	0	0

Also:

- *df/dt*: -1Hz/sec (corresponding to $H = 6$ and $Pa = 0.2$pu or $H=3$ and Pa=0.1pu)
- *df/dt, t* > ~2 seconds: 0.25 Hz/sec.
- Modulating frequency magnitudes decay with time.

Table 2: Model Data for Figure 2

The exponential decays applied to the modulating frequency amplitudes were used to represent what occurs in the real world, where oscillations recede over time.

A relay that monitors rate of change of frequency sees the differential of the above equation:

$$\frac{df_{bus}}{dt}(t) = \left(\frac{df}{dt}, sys\,avg\right) + \left(A \cdot 2\pi\ f_a \cdot \cos(2\pi\ f_a t + \alpha) + B \cdot 2\pi\ f_b \cdot \cos(2\pi\ f_b t + \beta) + \ldots\right) \quad \text{Eq. 15}$$

Frequency based load shedding relays are affected by these frequency swings. At any point in time the actual measured frequency will differ from average frequency by as much as $A+B+\ldots$. Rate of change of frequency relaying sees the rate of change vary from average rate of change in frequency by as much as $2\pi(A{*}f_a + B{*}f_b + \ldots)$. If an averaging technique is used, what is the time interval that needs to be used? A first cut would be that we need to average over about at least one cycle of the lowest modulating frequency we wish to filter out, but the longer we average, the better. However, this conflicts with our desire for fast operation of frequency based relays. When high speed is desired, a more common approach is to set the underfrequency pickup to some level beyond what would be seen by the summation of $A + B + \ldots$ under stable transient system conditions.

Watt and VAR Transfer Limitations

When a high load is applied, a high current is drawn. This, in turn, forces a voltage loss in the line reactance, which, in turn, means less voltage at the load. Depending on the load characteristics, this results in a point of diminishing returns. One finds that, for any line, there is a maximum Watt and VAR transfer rate. Beyond this maximum transfer rate is is found that as an attempt is made to increase loading by reducing load resistance, the net system loading actually falls. Normally the maximum Watt and VAR transfer rate is well beyond the levels at which one would operate a system, so it does not become a consideration in normal operating practices. It only shows up for serious overload conditions. Several of the references, [6], [7], [8], [9], and [10] cover this material.

The understanding of this helps in discussing load shedding from industrial and utility perspectives. For instance, from the industrial perspective, it gives a concept of what happens when a local generator operating in peak shaving mode is severely overloaded after a loss of tie to the utility. From a utility perspective, it gives an idea of when a line or a bus is at risk of voltage collapse.

Consider the radial system shown below.

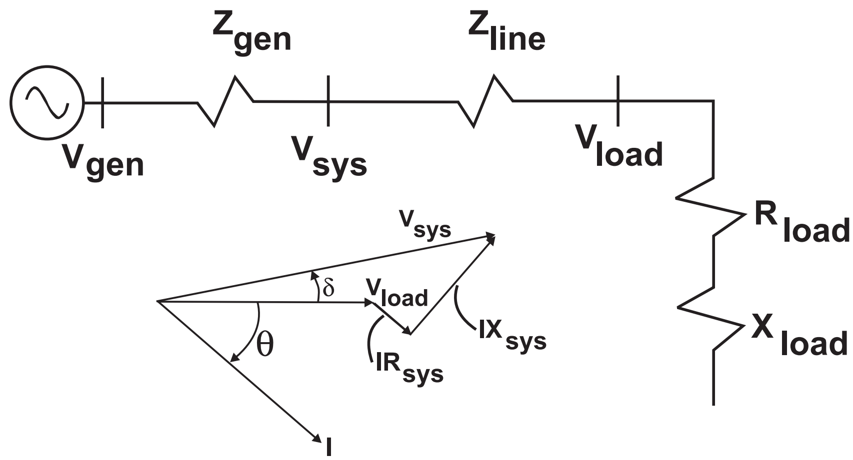


Figure 4: Simple System for Discussing Max Power Transfer Rates

The power transfer limitations will be reviewed below by two methods:

- *Floating Load Level Analysis*
  We can fix the source bus voltage, apply an overload at the load bus based on 1 per unit voltage at the load, allow current to flow and voltage to sag at the load bus, determine the load response to this reduced voltage, and then recalculate how much of our load we actually were able to pick up. This section is mainly concernd with the situations when large overloads are anticipated, such as industrial facilities with cogeneration.
- *Fixed Load Level Analysis*
  We can fix the source bus voltage and fix the P and Q level of the load, and using P-V and P-Q curves, see what load voltage we need at the remote bus to support, if possible, the desired load. This is a practice used by utilities to determine if a line or bus is at risk of voltage collapse.

Floating Load Level Analysis

One common, easily understood equation that represents the power flow in the above figure is:

$$S = P + jQ = \frac{V_s^2}{Z_{line} + Z_{load}} = \frac{V_s^2}{(R_{line} + jX_{line}) + (R_{load} + jX_{load})} \qquad \text{Eq. 16}$$

If the generator voltage and impedance are used, equation 16 can be stated as:

$$S = \frac{V_{g,internal}^2}{(R_{gen} + jX_{gen}) + (R_{line} + jX_{line}) + (R_{load} + jX_{load})} \qquad \text{Eq. 17}$$

In equation 17 note that, if generator impedance is being modeled, the internal voltage of the generator needs to be used to determine the power transfer. The impedance appropriate for the time of the analysis is used. For instance, since X_d'' applies only for the first few cycles after a fault, it is not appropriate for modeling the system if it is anticipated the load shed will not occur until 1 second after the event. More appropriate would be X_d', since it represents the generator impedance for the time frame of frequency based load shedding relay operation.

One trouble with using equations 16 or 17 is that commonly the load impedance is not clearly known. Many loads need to be modeled by impedances that vary with applied voltage, as is discussed further below. This makes a mathematical analysis an iterative approach. You do not know load power levels until you know voltages, and you do not know load voltages until you know feeder current levels, and you do not know feeder current levels until you know load power levels. The mathematical process is to estimate some variables, calculate to see if other parameters fall in line, and then improve the estimate until it appears you have a good picture of system conditions. This iterative approach, using the software MathCad, was used in generating the figures below.

Figure 5, 6, and 7 show the power limitations that arise from the voltage dependency of the system loads. Assume a system that can be modeled by Figure 4. Assume for this case that the generator is providing only some of the local loading and is running in parallel with other generation or the utility. This might be a peak shaving generator on an industrial scale or a local generator on a fairly isolated part of a utility, or it might be our upset system in Figure 1. Assume now that the parallel source of power is lost and the generator must now pick up all the local load. Figures 5, 6, and 7 give some ideas of what will occur. In each of the figures there are curves A, B, C, and D. Attempted overload, the X axis in the graphs, is in multiples of pre-fault loading that would have arisen if the voltage at the load had been maintained at 1.0pu. The Y axis of the graphs shows load voltage, actual generator overload after the effects of voltage decay is accounted for, and resultant frequency decay rate. An *H* of 6 is assumed in the graphs of frequency decay (a lower *H* will result in a faster decay rate).

No governor or voltage regulator response was taken into account in creating the curves. The purpose of the curves is to show system response in the moments after some event, before the dynamics of voltage regulator and governor response come into the picture.

The situation represented by each curve in Figures 5 through 7 is as shown in the following table:

Curve	Prefault Load, Power Factor	System Parameters	Load Watt Equation	Load VAR Equation
A	1.0 pu, Pwr Factor = 1.0	Z = 0.02+ j1.0 H = 6	$P \propto E^2$	$Q \propto E^2$
B	1.0 pu, Pwr Factor = 0.9	Z = 0.02+j0.35 H = 6	$P \propto E^2$	$Q \propto E^2$
C	1.0 pu, Pwr Factor = 1.0	Z = 0.02+j0.35 H = 6	$P \propto E^2$	$Q \propto E^2$
D	1.0pu Pwr Factor = 1.0	Z = 0.02+j0.35 H = 6	$P \propto E$	$Q \propto E$

Table 3: System Data, Figures 5 - 7

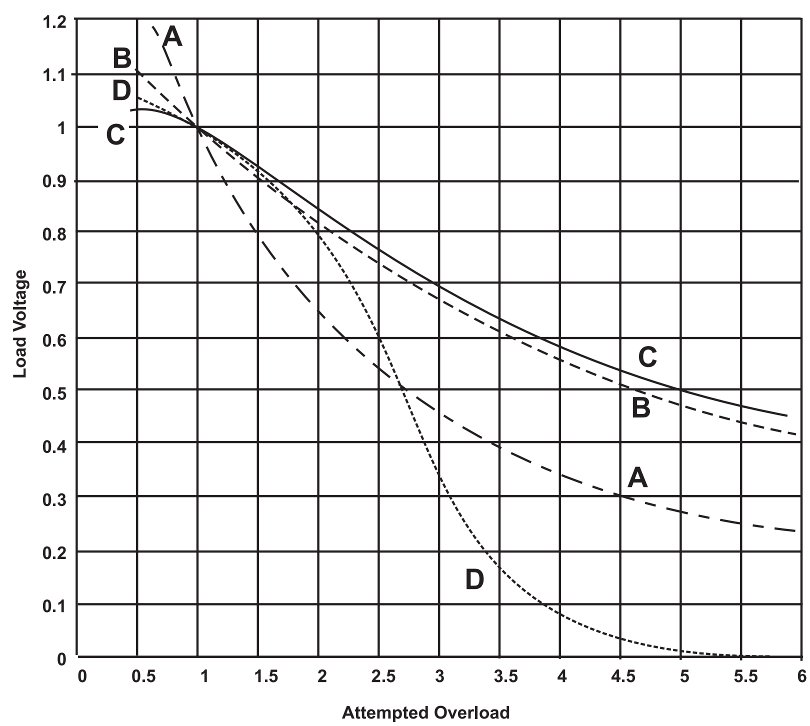


Figure 5: Load Voltage Versus Attempted Overload

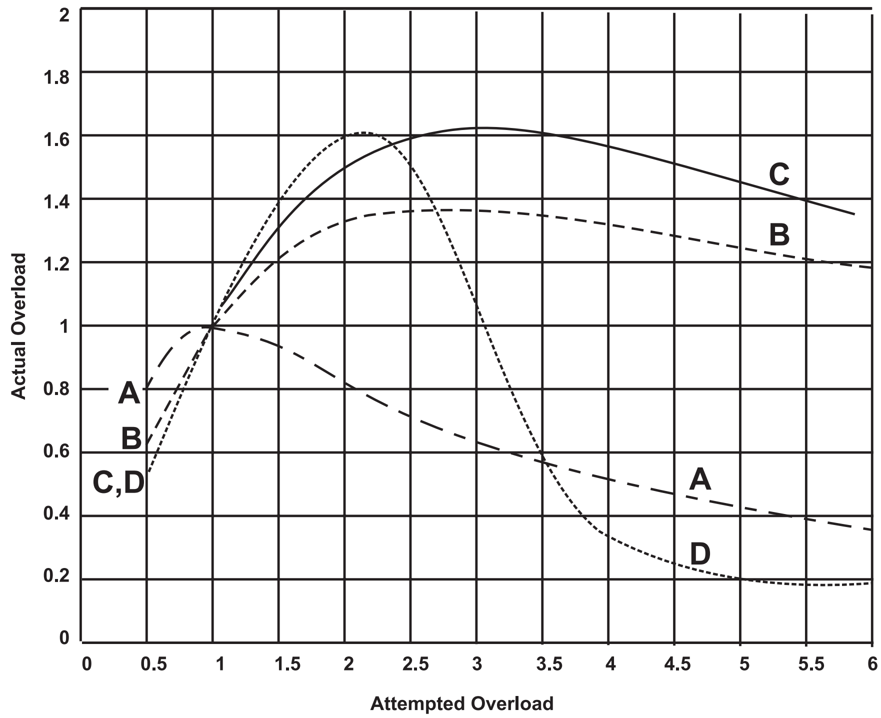


Figure 6: Actual Overload Versus Attempted Overload

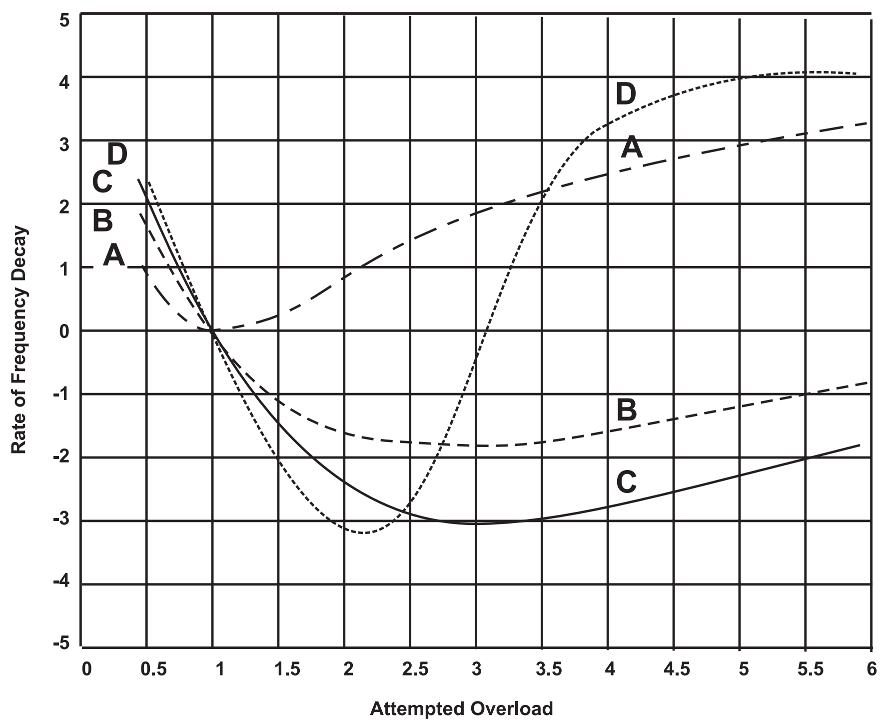


Figure 7: Initial Frequency Decay Versus Attempted Overload

Several informative things can be derived from these graphs:

- For overloads above about 2-3 per unit, the voltage drop that is experienced is a very limiting factor for whether the situation can be ridden through. Loads will likely drop out from undervoltage effects before the generator goes into a complete stall. This relieves the generator and reduces the severity of the overload.
- The magnitude of the overload that the generator sees is much less than the attempted overload. No system experiences overloads above 1.6 pu, no matter how much overload is attempted.
- The effects of system impedance can be seen by comparing curve A to the other curves. For curves B, C, and D, a typical value for the generator transient reactance (note: X'_d, not X''_d) was used, and in each curve the generator is shown to be able to support some level of overload. Curve A shows no overload carrying capability. In curve A an impedance of 1pu was used, which is somewhere between typical generator transient ($X_d' \sim 0.3$pu) and steady state reactance ($X_d \sim 1.8$pu), and is indicative of a several second duration overload condition without recovery from the voltage regulator, or the effects of substantial impedance/distance between the generator and the load.
- Comparing curve B and C shows the effect of VARs in the post event loads. In both, the pre-event load was 1pu Watts, but only for B were there VARs in the pre- and post-event loads. The VAR loading for curve B pulled voltage farther down and, hence, the generator was not able to put out as much real power as in curve C, where there were no VARs in the loads.
- The effects of load modeling is shown by comparing curve D to the other figures. A ‘constant current’ load, modeled as P and Q ∝ proportional to voltage rather than voltage squared, and which is representative of much of a system’s load, will cause a large voltage decay for the larger attempted overloads. The load voltage actually approaches zero, and the only load the generator sees is the line I^2R losses.
- Frequency relays commonly have undervoltage elements that are used to block operation during fault conditions. It can be seen that extreme overloads may cause voltage to decay so far as to block the frequency relay from operation.

Fixed Load Level Analysis - P-V and Q-V Curves

An important variation of Equation 16 used to represent Watt and VAR flow limitations of transmission lines states the Watt and VAR flow in terms of the magnitude and phase angle of voltage between the two ends of the line and the line reactance. Referring back to the phasor diagram in Figure 4, the equation for Watt and VAR flow becomes:

$$S_{load} = V_{load} I \cos(\theta) + jV_{load} I \sin(\theta) \qquad \text{Eq. 18}$$

where
θ = phase angle between V_{load} and I (+ is as shown in Figure 4).

Viewed from the sending end of the line the equation becomes:

$$S_{sys} = V_{sys} I \cos(\theta + \delta) + jV_{sys} I \sin(\theta + \delta) \qquad \text{Eq. 19}$$

where
δ = phase angle between V_{sys} and V_{load}

If we assume that *R* of the line is negligible, *IR* + *jIX* becomes just *jIX*. Then using some resultant right triangles that arise in the vector diagram, we can say

$$I \cos(\theta) = \frac{V_{sys} \sin(\delta)}{X_{line}}$$
$$I \sin(\theta) = \frac{V_{sys} \cos(\delta) - V_{load}}{X_{line}} \qquad \text{Eq. 20}$$

and we can restate equation (18) as:

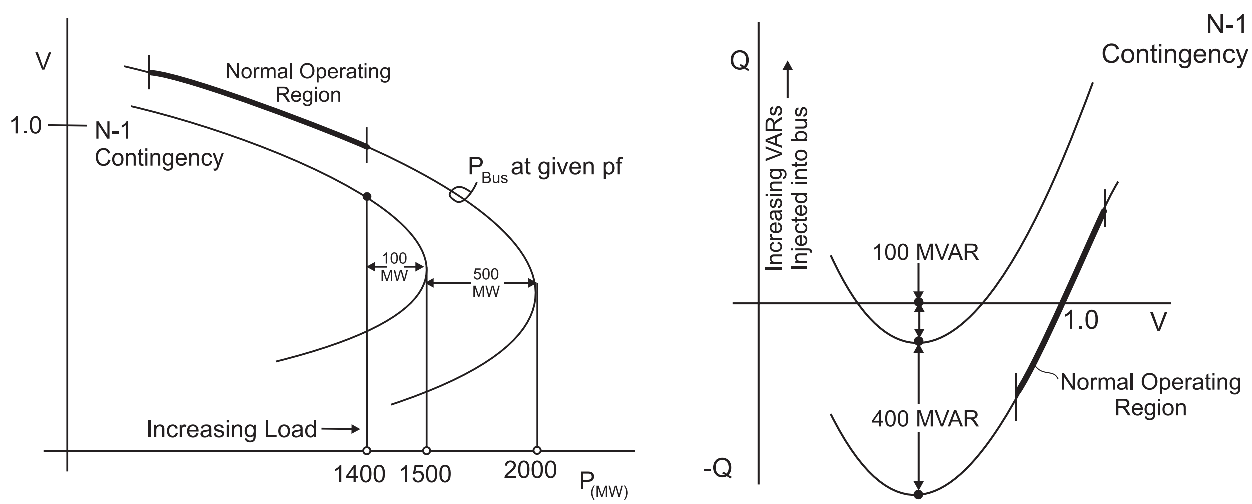
$$P_{load} = \frac{V_{sys} V_{load} \sin(\delta)}{X_{line}}$$
$$Q_{load} = \frac{V_{sys} V_{load} \cos(\delta) - V_{load}^2}{X_{line}} \qquad \text{Eq. 21}$$

If we assume *P* and *Q* of the load is known, and that the remote system voltage V_{sys} is fixed (i.e., it is a well regulated and strong remote source), we are left with two equations with two unknowns, V_{load} and δ. This is a bit troublesome to work with because δ is buried in sine/cosine terms and V_{load} is a squared term. Hence, given any system E_{sys}, X_{line}, P_{load}, and Q_{load}, an associated V_{load} *and* δ can be found. A more elaborate equation that includes line R can be derived, but for the accuracy we are dealing with, the above equations are satisfactory and commonly seen in print.

Equation 21 can be used to draw P-V and Q-V curves for radial systems These curves are also created for networked busses, but this requires the use of system load flow programs. The two sets of curves are generated in a slightly different fashion. Sets of P-V curves are created by gradually increasing loading at a fixed power factor at a bus and determining what resulting voltages are found at the bus. Sets of Q-V curves are created by setting a bus loading, then artificially injecting positive or negative VARS into the bus (changing the net load power factor) and determining what voltages result.

For a given P and Q level, there are two voltages that provide a valid stable condition. The curves in Figure 8 show that the system normally runs along the top part of the P-V curve and the right side of the Q-V curve. The curves show that for any given operating condition there is a limit as to how much additional power the line can provide for a given load power factor, or how much additional VARs can be drawn from the bus. The closer the system to the tip of the P-V or Q-V curve, the more unstable the situation is and, hence, the more the system needs to have its load reduced.

The system is considered unstable if, under any additional outage or major additional load, given present operating conditions, the system will be forced over the hump of the curve. One task of system planning agencies is to know the level of Watt and VAR margin available at any bus both with a given system configuration and load level and those contingency conditions for which they are designing their system. For instance in the figures below, the bus in Figure 8a may have 600MW reserve under normal conditions, but only 100 MW reserve under some contingency condition. Similarly, the system in Figure 8b may have 500MVAR reserve under normal conditions, but only 100 under some contingency condition.



Figures 8a, 8b: P-V and Q-V curve

Frequency and Voltage Effects on Loads

All loads are frequency and voltage dependent. The load shed process can take this into account to its advantage. During a system overload the decreased voltage, and possibly decreased frequency, load levels may not be as high as the pre-event condition. Consider the equations for real power and reactive power into a pure resistance and a pure reactance:

$$P = \frac{V^2}{R} \qquad Q = \frac{V^2}{X} \qquad \text{Eq. 22}$$

Differentiating (22) with respect to V:

$$\frac{dP}{dV} = 2V \qquad \frac{dQ}{dV} = 2V \qquad \text{Eq. 23}$$

Simple equations such as those above apply to few loads. One common model of a load used in system stability studies has the form of:

$$P(V,f) = P_0\left[k_{V1}\left(\frac{V}{V_0}\right)^2 + k_{V2}\left(\frac{V}{V_0}\right) + k_{V3}\right]\left[1 + k_f\,\frac{f-f_0}{f_0}\right]$$
$$Q(V,f) = (similar\ equation) \qquad \text{Eq. 24}$$

The first power term is for constant impedance loads, such as resistors. The second is for constant current loads, such as discharge lighting and the cumulative lumped load of many commercial establishments. The third is for constant power loads such as motors. Detailed information such as this is not easily available. More commonly published is data for a single term exponential model that takes the form of:

$$P(V,f) = P_0\left(\frac{V}{V_0}\right)^{K_{V,P}}\left[1 + K_{F,P}\,\frac{f-f_0}{f_0}\right] \qquad \text{Eq. 25}$$

$$Q(V,f) = Q_0\left(\frac{V}{V_0}\right)^{K_{V,Q}}\left[1 + K_{F,Q}\,\frac{f-f_0}{f_0}\right] \qquad \text{Eq. 26}$$

The following table lists some of the variations in Watts and VARs seen by the system for changing system voltage and frequency (drawn mainly from reference [7] and [11], but also [12]). These factors should be taken with caution. They are simplifications of a complex model and values vary considerably both seasonally and daily. Also, they were likely derived for small parameter changes, yet in a load shed event the parameter changes may be large. However, they are useful in obtaining a feel for what is happening to the generator loading as voltage and frequency changes.

Load	Power Factor	$K_{V,P}$	$K_{V,Q}$	$K_{F,P}$	$K_{F,Q}$
Residential	0.85 / 0.99	0.9 / 1.7	2.5 / 3	0.7 / 1.0	-1.3 / -2.3
Commercial	0.85 / 0.9	0.5 / 1.3	2.4 / 3.5	1.2 / 1.7	-0.9 / -1.9
Industrial	0.85	0.1 / 0.2	0.6	2.6	1.6
Large AC	0.8 / 0.9	0.1 / 0.5	2.5	0.6-1.0	-1.3 / -2.8
Fan Motor	0.9	0.1	1.5	3	1.7
Pump Motor	0.85	1.4	1.4	5	4.2
Resistance Heat/Cool	1.0	2.0	0	0	0
Fluorescent Light	0.9	0.95	7	1.0	-3
Incandescent Light	1.0	1.5	0	0	0
Elec.Pwr Plant Auxiliaries	0.8	0.1	1.6	2.9	1.8

Table 4: Static Load Characteristics with Voltage and Frequency Variations ([7], [11])

The net effect is that the overload is less than anticipated. While an accurate representation of the system requires computer modeling, an idea of what occurs can be gained from modeling just one of the parameters. Suppose voltage remained constant, and that the generator governor did not respond at all and continued to put out just as much power as before the overload arose. The final frequency is gradually approached (power mismatch decreases as frequency decreases) and is (after a bit of thoughtful integration and algebraic manipulation of equation 25) sometimes referred to as the load frequency damping (Reference [13], [14]).

$$f(t) = f_0\left(1+\frac{P_a}{D}\left(1-e^{\frac{-Dt}{2H}}\right)\right) \qquad \text{Eq. 27}$$

Where

$$D = \left(K_{F,P}\left(1-P_a\right)\right) \qquad \text{with constant power generation}$$

or

$$D = \left(K_{F,Q}\left(1-P_a\right)\right)+P_a \qquad \text{with frequency dependent power generation} \qquad \text{Eq. 28}$$

The second form of the equation for *D* is an attempt to model the decreased generation resulting under decreased turbine rotational speed and is found in [13] and [14]. Generator output changes with frequency and voltage is discussed further below in 'Generator Response.'

The equations above are set up for P_a being negative for an overloaded system.

The system approaches its final frequency gradually. We can solve equation 27 for time to reach a given frequency. The equation takes the form of:

$$t(f) = \frac{-2H}{D} \ln\left(1 - \frac{D\left(\frac{f - f_0}{f_0}\right)}{P_a}\right) \qquad \text{Eq. 29}$$

Applying these equations to a real system, assume that:

$$P_a = -0.1 \qquad \frac{dP}{df} = 1.5 \qquad H = 3$$

By setting *t* in equation 27 to infinity and using the second form for *D*, we can tell the final frequency of the system is:

$$D = (1.5(1 - -0.1) + -0.1) = 1.55$$
$$f(t = \infty) = 60\left(1 + \frac{-0.1}{1.55}\right) = 56.13\,\text{Hz}$$

The time to reach 58 Hz is:

$$t(58) = \frac{-2 \cdot 3}{1.55} \ln\left(1 - \frac{1.55 \cdot \frac{58 - 60}{60}}{-0.1}\right) = 2.81\,\text{sec}$$

For comparison, using equation (13), which is for the straight line approach to frequency decay and assuming constant generation levels:

$$t(58) = \frac{\frac{58}{60} - 1}{\frac{-0.1}{2 \cdot 3}} = 2\ \text{sec}$$

Load Dropout Due to Undervoltage

Several types of loads drop out if there is a serious undervoltage, thereby inadvertently there is an automatic load shed:

- Motor Starters will drop out if voltage reaches 50-75% of rated.
- Discharge lighting extinguishes at about 80-90% of rated voltage, and may or may not automatically restart.
- Adjustable speed drives (ASD) drops out at about 80-90% of rated voltage.
- Similar to ASDs, other rectifier or thyristor based power supplies may drop out at about 80-90% of rated voltage.

Generator Response

Generator response to frequency and voltage disturbances needs to be considered as well. For events lasting more than a couple of seconds, the voltage regulator may start to react, and shortly thereafter the governors. Other factors are also coming into the analysis as described below.

Frequency Dependence of Generator Power Output

The torque generated by a turbine or any type of prime mover is optimized for the base frequency of the unit. When frequency decays and there is no reaction yet from the governor, we cannot simply say either that power or torque remains constant. Power output of a generator is proportional to torque times speed. If power stays constant and speed falls, then we are saying torque went up. If we say torque remained constant and speed falls, we are saying generator power output decreased and, hence, the situation is actually worse than in our simple analysis where we assumed the generator power remained constant as frequency fell. References [14] and [15] review this problem. Prime mover manufacturers need to be consulted to learn how their units respond to off-frequency operation.

Governor Response

In most transient analysis studies, the prime mover is expected to change power output very little in the first second or so after an event. However, if the frequency decay reaches the two- to ten-second time frame without tripping the generator and it is assumed that there is some spinning reserve in the system (i.e., the generation was being operated at less than 100% of full load), it is quite feasible for the prime mover to be involved. Every type of generation has a different time constant involved in how fast the generator can pick up a major load increase, but the time frame of five seconds to tens of seconds is common. Some systems are slower. Hydro facilities with long penstocks make take several minutes to pick up large quantities of load. Steam turbines that do not allow boiler fast valving (i.e., units where sudden boiler pressure changes are not allowed, so the boiler heat input must be stepped up before steam output may be changed) may reach the time frame of long boiler time constants (tens of minutes) to change power output.

Voltage Regulator Response Time

Similar to the governor response, the regulator response may not be involved in the first moments after a major load increase. Regulators, however, tend to have a faster response than governors do. The regulator itself may boost the field voltage within a matter of cycles, but the time constants involved with the current in the field actually rising is typically in the order of 1-5 seconds. In the first second after a fault, the time constants of the sub-transient and transient impedances play a major role in determining the voltage that will be impressed on the load.

Voltage Regulator Volts/Hertz Drop-off

Another factor involved with voltage regulators is that many regulators have a volts per hertz setting that automatically decreases voltage when frequency decays. This does not usually become a factor unless frequency decay is in excess of about 58Hz and likely does not become substantial until about 56Hz or below. The typical action is to reduce the per unit voltage proportionately to 1 to 3 times the per unit frequency reduction, starting at 56-59Hz.

Voltage Regulator Short Time Overload Capability

A voltage regulator has the ability to provide short term field current boosting to support the system during a fault or system disturbance. However, if the current boost remains too long, the regulator cuts back and the low voltage conditions that initiated the boost return. Time frames depend on the level of the overload, but for a ‘feel’ for the matter, a field current of 20% above rated current could commonly be held for a minute or two. This is a factor with SCADA and voltage based load shedding system.

Frequency Dependence of Generator Voltage Output

Yet another consideration is the reduced voltage that is produced by a generator as the generator slows. If field is held constant, a slowly moving rotor produces a lower output voltage proportionate to the speed decrease. Recall that induced voltage is due to d(flux)/dt which, as seen by a stator winding, is proportionate to rotor rotational speed as well as rotor field current. Hence, if speed slows, then d(flux)/dt reduces as well, until the voltage regulator responds and raises field current.

Off Frequency Restrictions: Turbine Blades

The power system is optimized around the base frequency. More problems than can be accounted for arise if the system were operated off nominal frequency. However, one major problem getting more attention in literature than any other deals with vibrations that arise in turbine blades when the generator is operated at off nominal frequencies. Most turbine blades have resonant frequencies that lie in the neighborhood of the fundamental base operating speed of the turbine. If the generator is run at these resonant frequencies under load for any extended period, there is cumulative damage to the blades and an eventual failure of the turbine. There is an IEEE standard, C37.106 [16], written on this subject The allotted off frequency times for the generators are cumulative over the life of the generator and should be available from the manufacturer. The underfrequency relay must not only trip faster than is specified in the standard, it must trip *much* faster so that the cumulative time of every underfrequency event over the life of the generator does not exceed the manufacturer’s recommendations.

Figure 9 is from the IEEE standard. It is a worst case scenario. It takes the frequency allowances from several manufacturers and compiles their recommendations to one worst case graph. Hence the graph may not apply to many systems because the system may not have every generator that was used by the compilers of the standard.

Note that generators are commonly rated to run continuously over the frequency of 59.5 to 60.5 Hz. This is a consideration for frequency based load shed relaying.

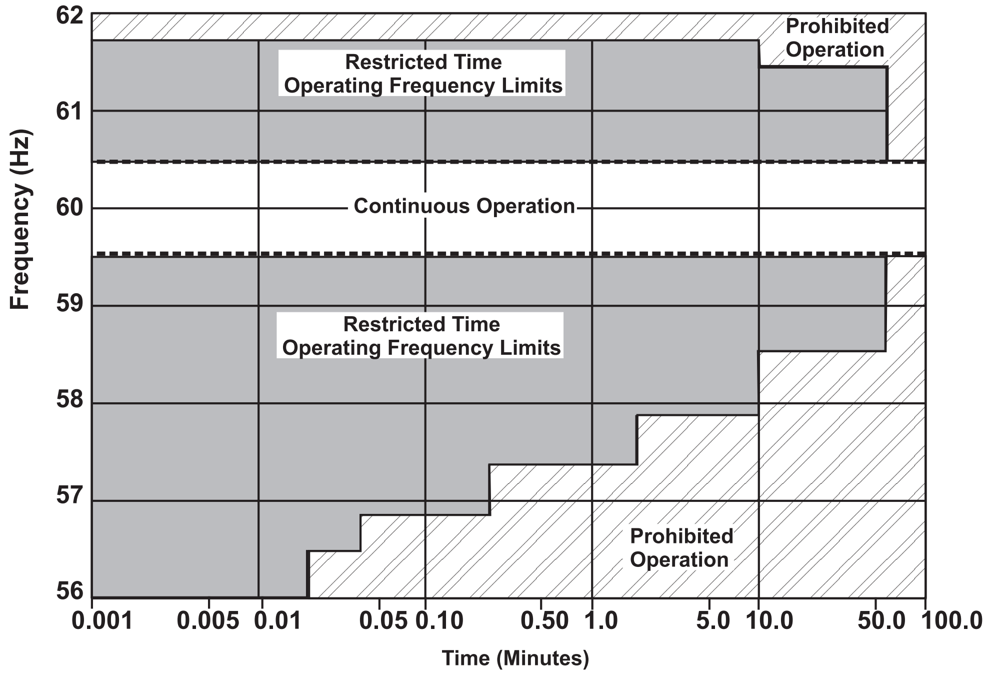


Figure 9: IEEE C37-106 Worst Case Frequency Withstand

METHODS OF OVERLOAD DETECTION AND LOAD SHED

To organize the discussion of this topic, while there is some overlap and backup, consider that there are the following separate means of automatically detecting and subsequently, manually or automatically, correcting the system overload condition.

- Frequency Monitoring
- Voltage Monitoring
- SCADA System Monitoring
  - Application to Utility Scale Systems
  - Application to Smaller Industrial Facilities
- Current and/or Power Monitoring

Frequency Monitoring

Frequency monitoring is a high speed means of detecting a major system upset, but it must by its nature wait for serious conditions to exist, including islanding and/or generation already slowing down, before it acts. Once frequency has strayed far enough from nominal that it can be assured a system upset has occurred, there may be only fractions of seconds to maybe tens of seconds for the necessary load to be shed before the system totally collapses.

Underfrequency Load Shed Settings

Using the initial rate of frequency decline previously covered, we can determine how to set the relay. Before continuing, note that modeling the frequency deviation in this fashion is fairly crude and does not represent the dynamics of load and generator response to the system frequency and voltage conditions. It does give a concept from which to proceed.

1) Choose a minimum frequency that allowed for the system.
2) Decide on a maximum mismatch of load verses generation that is ever expected to occur.
3) Disperse the load shedding assignments at various frequencies so that some occurs at frequencies prior to the end frequency.
4) Starting with the maximum anticipated overload, and possibly some more likely lower overload levels, estimate the time the system will be operated off nominal frequency. This is done by computing the initial rate of frequency decline and recovery using methods previously described. The process is to
   a) estimate frequency decline rate,
   b) determine when the load shed frequency will be met,
   c) estimate a new frequency decline rate after the load shed,
   d) then determine when the next load shed frequency will be met,
   e) continue until enough load shed steps are hit to allow frequency to start to increase, and
   f) calculate when frequency recovers to an acceptable level.
5) If the recovery time is beyond the governor response time, some allowance for governor response may be included. If low voltages are expected at the loads or frequency dip is low, some allowance for load dropout may be considered.
6) Calculate how long any generator will be exposed to various frequencies, comparing to the recommended operating times of the generator manufacturer or figures such as provided in C37-106. If more than a small percentage of the usable life is used, the load shedding may need to be more aggressive and earlier.

For instance, given a 20% overload and an *H* of 6, and assuming a minimum allowed frequency of 57Hz, either of the above figures shows that we have about three seconds until the system condition becomes unacceptable. To prevent this frequency from arising, we chose to drop 8% load at 59 Hz, and 58.5 Hz. At 58 Hz we drop 12%, since this may be our last chance. The simple frequency analysis is shown below. It shows that the system sees frequencies of less than 59 Hz for almost three seconds and less than 59.5 Hz for almost four seconds. A more complete load and generator model would likely show a notably different frequency decay profile (and the last load shed event may not have even occurred due to governor response and inadvertent load dropout), but only a system stability analysis program can determine this with a good degree of accuracy.

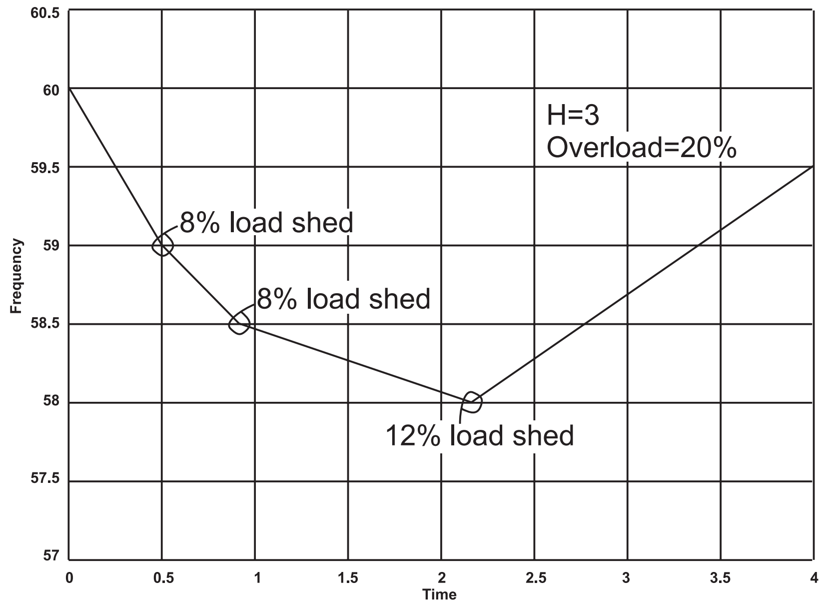


Figure 10: System Simple Frequency Decay and Recovery Analysis

Normal local frequency swings as local generation oscillates back and forth with respect to the rest of the system after a local system disturbance such as a fault or a line switching operation This causes frequency to shift from the nominal 60 Hz. To prevent the frequency relaying from responding, frequency relays are not normally set above about 59.5 Hz without at least some time delay.

Underfrequency relaying commonly has an undervoltage block function. The function serves to block load shedding when potential to the relay is lost and to block operation during fault conditions. It also serves to block operation during some radial load situations. In the radial load situation, suppose a substation on a radial line feeds a facility with a large quantity of motor loads. Suppose there is a fault on the transmission line to the substation and the substation is de-energized. Then, suppose the motor loads support voltage at the substation for a short period but with a rapidly decaying frequency. In this condition the frequency relay operates to trip the substation main breaker. Now when the transmission line is re-energized the substation is left in the dark. Undervoltage block may be used to prevent this situation. Typical settings for the undervoltage block are about 70-90% of nominal.

However, if the frequency relay is being used to detect severe overload conditions, the undervoltage block function may need to be set to possibly 50% of nominal. This opens up a greater risk of the relay tripping for fault conditions. There are two means of giving additional security against relay misoperation for this condition. Either 1) add time delay to the relay to allow it to ride through the situation, or 2) use a relay that monitors all three phases. It is uncommon for a fault to occur on all three phases that affects the frequency measurement on all 3 phases.

Voltage Disturbance Effects on Relaying

A frequency relay can be fooled by some stable system conditions. Three sources of misoperation are.

- Voltage Wave Distortion Effects

The common way to measure frequency is for the relay to derive frequency from voltage zero crossings, with either front end analog filtering or digital numerical filtering. Figure 11 shows that the fault causes some non-60 Hz zero crossings. Depending on how the filtering is arranged, this could affect the frequency measurement for one or two cycles. If the fault is slowly evolving or re-striking, or if the fault causes an even larger shift in the system neutral point, it is shown that it may be possible to have additional errors in the frequency measurement.

The problem can be mitigated by a couple of methods, most of which slow the relay operation a small amount. The design of the frequency sensing element can have improved filtering. Operation can be blocked until several underfrequency cycles in succession are sensed. The relay can look at either the positive or negative going zero crossings only, which tends to average out the voltage phase shifts caused by faults and remove the effects of DC offset. The user’s time delay setting further filters out this mode of misoperation.

Another option is to use three phase frequency sensing. It is uncommon for a fault to distort the frequency on all three phases. By using an “AND” function such that underfrequency must be detected on all three phases, a greater degree of security is obtained.

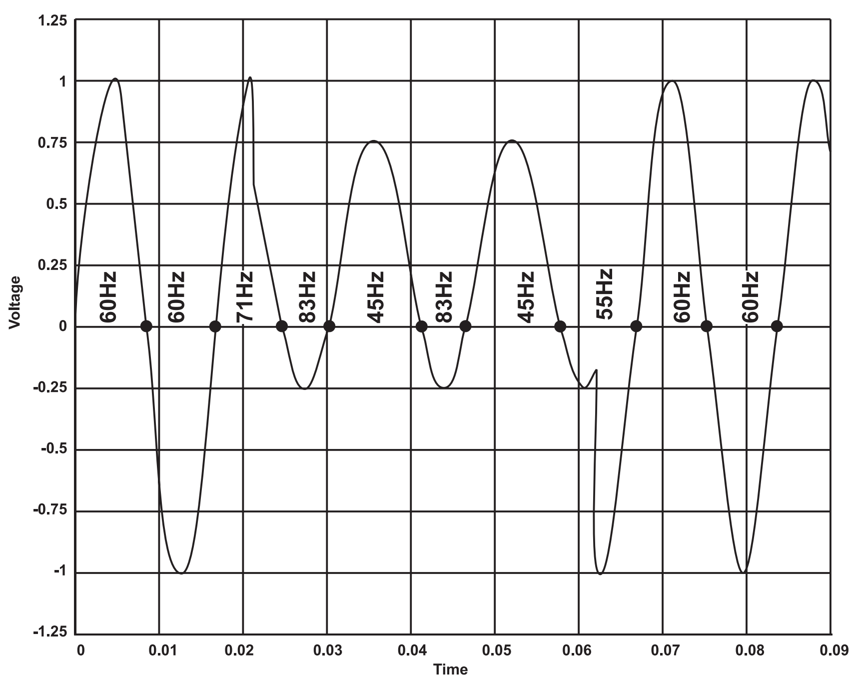


Figure 11: Voltage Distortion Effects on Frequency Measurement

- Local System Frequency Swings

As previously discussed, after a disturbance in a power system there may be local frequency swings as generation swings back and forth with respect to the balance of the network. These swings occur independently of whether there has been a system islanding condition. Equation 14 applies in all system disturbances, even if average frequency stays at the system nominal frequency. If these frequency swings are severe, they can lead to the momentarily picking up of an underfrequency relay.

There are a couple of means to prevent this problem:

1) Use relay frequency pickup settings that are outside the realms of these normal frequency swings. This is one reason settings above 59.5 Hz are not used often (another is that generation is typically rated to operate continuously from 59.5 to 60.5 Hz).
2) Add a small amount of time delay. However, frequency swings can have relatively long cycles, so long time delays are needed to totally filter this effect out. Frequency swings with 0.2-3 second duration cycles are commonly seen in frequency disturbance plots.

An example of the effects of a stable swing on an underfrequency relay is shown in Figure 12. If the swing has an amplitude of 0.5 Hz, and the relay has a setting of 59.75 Hz, the relay senses frequency less than its setting for 0.33 seconds out of each frequency swing cycle. See below for a description of what occurs.

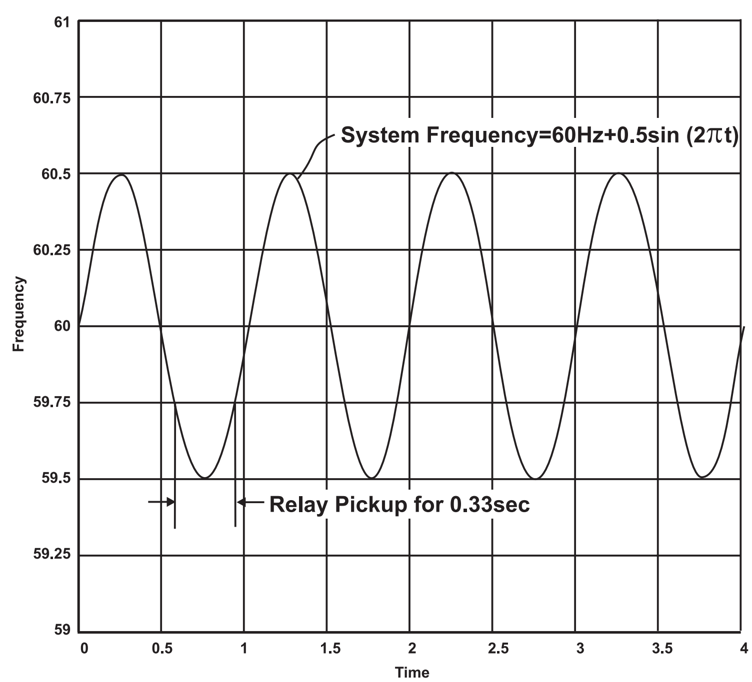


Figure 12: Frequency Swing Effects on Relay

Follow up questions to the above discussion are, “What are the normal frequency swings? Do they ever go beyond 59.5 Hz? And if they do, what time delay do I need to add to prevent operation for any given frequency?” There is no answer to these question here. It is hard to say what a common frequency swing is. The experience appears to be that local stable frequency swings beyond 59.5 Hz are uncommon. The application of frequency relaying as described in the tables to follow shows what typically has been successful implementation of underfrequency load shed relaying. Note 59.5 Hz is the highest underfrequency setting used.

Harmonic Distortion in Voltage Wave

A severe high frequency harmonic distortion in the voltage wave form can cause early and late zero crossings. This is usually not too much a problem with relays due to filtering techniques. Higher frequency distortions are commonly filtered out either in the analog front end of the relay or the digital processor in numeric relays.

Load Restoration

Load restoration should be no faster than the rate at which sufficient additional spinning reserve can be added to the system to ensure that the system remains stable after the additional load is added. If done automatically, the typical means is to add load back after frequency has restored to normal frequency plus a stabilizing time delay. While the sustained normal frequency is indicative of a stable system, only system operators can be sure that the system is in good condition and ready to accept the new load. The automatic restoration of load, therefore, has drawbacks and is questioned by some System Coordinating Councils. The desire on the part of system owners to get load re-energized as quickly as possible creates pressure to restore load automatically.

Rate of Change of Frequency

Rate of change of frequency is not often used by most utilities. One reason it is not frequently utilized is that the relaying required to perform the task has not been commonly available in the relaying market. If it is made available, it can serve to make for a faster response to an overload condition. Rate of change of frequency allows faster load shedding under serious conditions. Rather than wait for absolute frequency to ultimately decay, if a high rate of frequency decay is seen, then it is indicative of a major overload.

However, this type of frequency monitoring may be subject to responding to stable system frequency swings. Note in Equation 15 the derivative sees the frequency in the cosine function magnitudes, so during high frequency but stable swings the rate of change is seen as relatively high for short durations. Some time delay or averaging of the rate of change of frequency helps the relay ride through this effect. For instance, assume that the system rate of frequency decay was 2 and there was only one modulating frequency of 2Hz and 0.25 magnitude. Applying Equation (15):

$$\frac{df_{bus}}{dt} = (2) + \left(0.25 \cdot 2\,\pi\,2 \cdot \cos(2\,\pi\,2\,t)\right)$$
$$\frac{df_{bus}}{dt}\,(t = 0) = 2 + 3.14 = 5.14 \text{ Hz}$$
$$\frac{df_{bus}}{dt}\,(t = 0.125) = 2 + 0 = 2.0 \text{ Hz}$$

This shows that by adding some time delay to require that rate of change be sustained for a given period, or using some averaging in the measurement process, the swings from the rate of frequency change measurement can be leveled and smoothed.

Typical Settings

Table 5 lists load shed setting reported by a variety of users [1], [16], [17], [18], and [19]. This is a simplified review of settings that the sources may take several pages to explain in the original documents, so the table should not be used as a definition of what the sources use.

	WSCC	NPCC	MAIN	ERCOT	ECAR	C37.106-A1	C37.106-A2
Setpoint 1	59.1	59.3	59.3	59.3	59.5	59.3	59.5
Time Delay	<14 cy*	<45 cy*	6 cy	<30cy	-	6	6
% Shed	5.3	10	10	5	5	10	10
Setpoint 2	58.9	58.8	59.0	58.9	59.3	58.9	59.2
Time Delay	<14 cy*	<45 cy*	6 cy	<30cy	-	6	6
% Shed	5.9	15	10	10	5	15	10
Setpoint 3	58.7		58.7	58.5	59.1	58.5	58.8
Time Delay	<14 cy*		6 cy	<30cy	-	As Rqd	6
% Shed	6.5		10		5	As Rqd	5
Setpoint 4	58.5				58.9		58.8
Time Delay	<14 cy*				-		14
% Shed	6.7				5		5
Setpoint 5	58.3				58.7		58.4
Time Delay	<14 cy*				-		14
% Shed	6.7				5		5
Setpoint 6							58.4
Time Delay							21
% Shed							5
Stall Point 1	59.3		59				
Time Delay	15 sec		5 min				
% Shed	2.3		10				
Stall Point 2	59.5		<Nominal				
Time Delay	30 sec		10				
% Shed	1.7		10				
Stall Point 3	59.5						
Time Delay	60 sec						
% Shed	2.0						

* Relay time plus breaker time

Table 5: Typical Utility Underfrequency Load Shed Settings (Simplified, Partial)

Example Schematic - Distribution Substation

Load shed relays are typically placed in distribution substations throughout the system. In historic practice, there is one frequency relay placed at each substation that is set to trip the entire substation off line when the parameters are met. The amount of load assumed to be shed is based on historical substation data and the assumption that the percent of the system that each substation represents does not fluctuate (since all loading in the system is to a large degree going up and down in magnitude together).

However, as the role of multifunction feeder relays increases, the frequency function is slowly moving to the feeder protection relays. In today's market multifunction feeder relays typically have frequency relaying included. So in substations with newer relaying, feeders may be individually tripped, and feeders with more critical loads not tripped until higher frequency decay occurs, or not at all.

Figure 13 shows a possible schematic that takes several of the features previously discussed for load shedding into account. It has:

- two high speed load shed steps,
- one low speed load shed step for underfrequency stalling conditions,
- two step delayed automatic load restoration,
- one high speed load restoration for frequency overshoot conditions,
- rate of change of frequency relaying supervised by an absolute frequency measurement module and that uses a small time delayed averaging scheme,
- has undervoltage blocking,
- uses 3 phase frequency and voltage magnitude sensing for security, and
- has reverse power supervision so the bus is shed only when it is drawing power and not when its generation is supporting system power requirements.

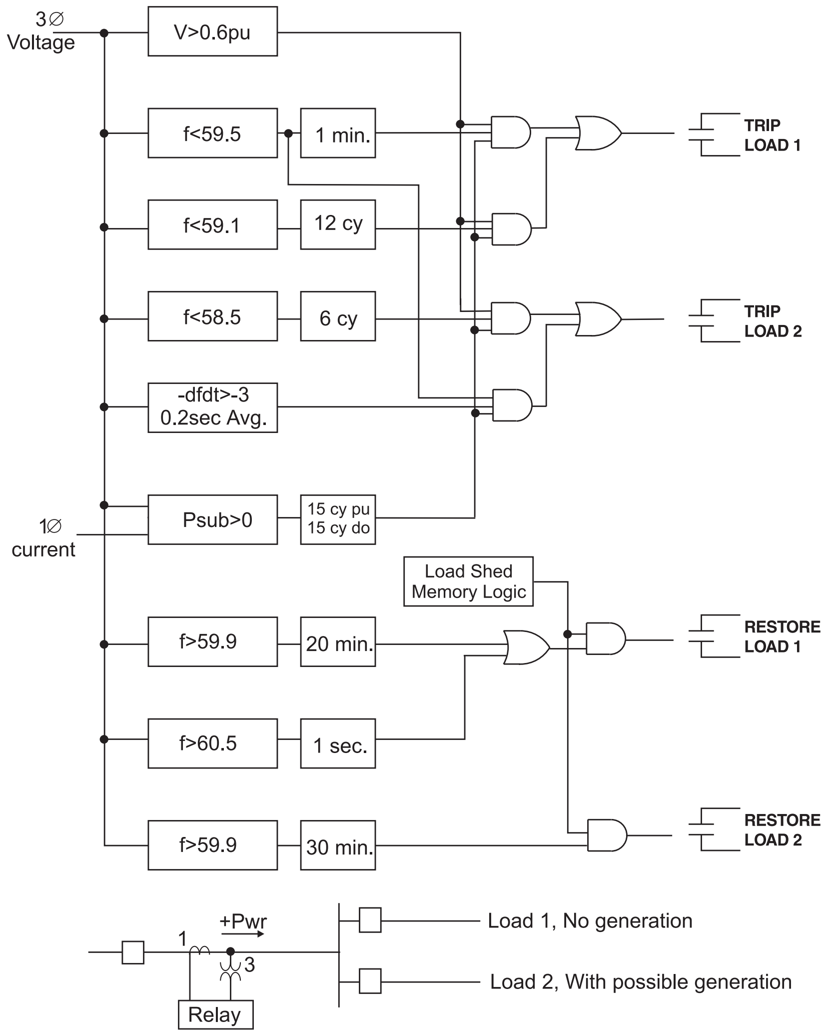


Figure 13: Frequency Based Load Shed Schematic

Under-Voltage Based Approach

For the purposes of this section consider voltage based load shedding as a system with a dedicated relay that sheds local load when the relay sees three phase voltage depressed for an extended period (2 seconds to maybe a minute, depending on what non-load factors could cause voltage depression). This is indicative of an overload. Undervoltage load shedding that is monitored and supervised by a SCADA system or some other type of central computer is discussed in the section on SCADA based load shedding.

Voltage based load shedding cannot be set to operate as fast as frequency based load shedding because by nature undervoltage can be fooled by the voltage dip caused by faults and load energization.

Utility Application

Voltage monitoring of a power system is a means of detecting an overload condition that can, in certain cases, predict a problem arising and preemptively shed loads before a chaotic system breakup occurs. Referring back to the system shown in Figure 1, if undervoltage load shed relays had been installed at the loads near Generator E the problem may have been prevented from progressing. An example application of undervoltage relaying may be found in [10] where undervoltage relaying as applied to the Puget Sound (Washington) area is described.

Industrial Application

Undervoltage load shedding is harder to apply to industrial facilities but still quite applicable. In some facilities undervoltage load shedding is actually an important part of the protective relaying for some equipment. Some equipment may not be able to tolerate being run at undervoltage conditions for any extended period. A difficulty is that in an industrial facility there may be loading conditions that could fool an undervoltage relay. There may be an old practice in the facility of allowing the system to run at fairly low voltages for extended periods during some heavy load conditions.

Pre-Installation Studies

Virtually all the analysis required by this load shed scheme is in the pre-installation phase when system voltage profile studies are run prior to implementation to determine settings and the best placement for the relaying. The studies are basically voltage stability and voltage profile studies. Some references on voltage stability as applied to voltage based load shedding or that provide some level of information not requiring an extensive mathematical background to be grasped are [7], [8], [9], and [10].

Relay Description

The relay itself performs a relatively simple task of measuring voltage, comparing each phase to a set point, and starting a timer when voltage drops below a set point on all three phases. Note this arrangement will not be fooled by the loss of one or two VTs. The relay may have a permissive that blocks operation if voltage falls too low to prevent operation when a line is deliberately de-energized or if all three VTs fail (fuse removed inadvertently). Positive sequence voltage measurement is not optimal for this application because positive sequence voltages are depressed during any type of fault and under the loss of just one VT. It may be possible to supervise the undervoltage relay with an overcurrent relay or overpower relay to give additional security, but the overload causing the undervoltage may be remote from the location of the undervoltage.

Settings

The pickup setting should be high enough to prevent the relay from operating under normal but low system voltages, but not so low that the function never operates for overload conditions. Typical settings are in the range of 85%-90% of nominal voltage.

This setting is not too hard to surmise from a rough analysis of how a system typically operates. Suppose a high voltage power system runs over a range of ±5% of some target nominal voltage. Under emergency conditions the system may be asked to supply voltage another 5% below nominal. The relay must be set, therefore, at some comfort level below 90% of the target nominal voltage. System load flow studies under all normal contingency conditions are run to verify the settings are not too high. Then system load flow studies under serious abnormal conditions are run to determine if the relay would operate to help alleviate the problem.

The time delay must be longer than the longest anticipated time delay of fault detecting relays for faults of a type that could fool the undervoltage relay and time delays of equipment that automatically clear the condition, such as tap changers and excitation systems. If the startup energization of any load in the area could depress voltages this also must be considered.

There is a maximum time delay that must be considered as well. After an event when generation is lost, the remaining generation picks up the load. It is possible to cause some generation to go into a mode of field current boost. A generator field can support excess field current for a short period, but some generators have protective equipment to limit this high excitation current after 1 to 2 minutes. At the same time this is occurring, distribution tap changers are timing out and will shortly start to raise voltage and, thereby, increase loading on the system. Typical tap changer delays are in the 30 second to one minute delay time frame. Hence, if there is an upset in a system but the system appears to hold together, there may be a time delayed problem waiting to happen. There may be only a short time during which the system remains operational. References [8] and [10] discuss this problem.

Undervoltage Load Shed Difficulties

There are difficulties associated with proper application of undervoltage load shedding:

- The undervoltage setting should be below the lowest normal operating voltage of the monitored line to prevent the problem of operation for acceptable but high load levels or transient loading conditions. This opens the possibility that the relay may not detect unstable conditions where voltage is not below the set point of the relay. Suppose for some reason a system was being run at 105% voltage. Suppose that the system was designed so that the loss of any line would not cause a nearby bus to lose more than 10% voltage, but no more than 5% typically. Suppose that two lines are lost and voltages drop 15% (to only 90% of nominal) and the undervoltage relay never operates to shed load.
- There are notable limitations to where the relaying may be appropriately applied. If it is placed on a distribution line the effects of auto tap changers mask a system overload condition from the relay, or alternatively a line switching operation or the startup of a large industrial plant on one feeder could fool the relay. The relay would not be appropriate at locations directly adjacent to generation powerful enough to control

bus voltages even during severe overloads. The relay is best applied to locations with fairly stiff voltages under all normal conditions, so a low voltage condition will reliably indicate a severe overload condition, as may be assumed to be the case at large substations associated with bulk power transmission lines.

- Bulk power transmission stations may be remote from the load to be shed, further complicating the implementation.
- Due to the security question, the undervoltage relaying might be supervised by another condition. For instance, the relay might be used in conjunction with a communication system that can have logic such as "if high excitation at generator X and if low voltage at substation Y then trip N% of load at substation Y." This now begins to border on the SCADA system reduced parameter approach described below.
- In choosing time delays, an analysis is needed to determine whether the tap changers are clearing a problem or re-energizing the overload problem.

SCADA System Approaches

Within the framework of SCADA system overload detection there are two notably different applications:

- The large utility scale SCADA system with huge quantities of data coming in from a huge geographic area, and
- A smaller industrial SCADA system monitoring a facility where islanding or system upset can be detected as simply as monitoring generation levels and the tie to the local utility.

Large/Utility Scale SCADA Implementation

On a system-wide basis it becomes much more difficult to detect a system upset condition than in the industrial facility case. Detecting the upset condition involves monitoring hundreds or even thousands of breakers, many generators, and many tie lines. Distances are in the tens to hundreds of miles. The condition of any one of the monitored devices or even a group of them does not necessarily indicate a system upset. The condition of the system as a whole must be considered. Also, for a utility the objective is not just to detect when an upset has already occurred but to recognize before the fact that a system upset is about to occur so steps can be made to correct the problem early and limit the number of customers affected.

Stability calculations take substantial computing power. Between the calculation time and the SCADA communication system delays it is obvious that there are speed limitations in this approach to detecting overload conditions in "real time." There are approaches to speeding the calculation step. Some eigenvalue procedures have been devised that require comparatively low levels of calculation and that allow the calculation to proceed in real time. One example means is shown in reference [20].

Another method to make this process more useful for load shedding is to run system case studies ahead of time. This allows the identification of some possible unstable system overload conditions. One can then automatically and constantly compare a smaller subset of critical system conditions to the case studies to see if an unstable overload condition exists. This may be performed on a separate dedicated computer within the SCADA system.

An example is found in reference [21]. In this example Southern Florida is identifiable in the analysis by its limited ties to the balance of the North American system. By monitoring transmission level voltages, magnitude of Watt and VAR flows in critical locations (generators and transmission lines), and fast acting changes in Watt and VAR flows in critical locations, a specific set of system upset conditions can be recognized. If such a situation arises, load is shed to bring the system into predetermined acceptable operating conditions before southern Florida becomes islanded from the larger eastern U.S. grid. There are comparatively few locations monitored, and the logic required to determine if load shedding is required is relatively simple. Extensive computing power is not required. The time delay in such a system is mainly that of the communication system.

A SCADA based utility scale automatic load shed system is by nature a relatively slow acting system as compared to the speed described for a frequency based load shedding system. The types of overload that a SCADA system may respond to are, therefore, those involving the short term overload ratings of equipment.

Discussion

The scenario previously described in Figure 1 is one in which a properly programmed SCADA based load shed system computer could detect and prevent. If the SCADA system had been smart it might have recognized the incipient problem with the generation at bus D and shed load at bus D, or possibly increased the voltage set point at nearby generation to relieve the bus D generator and, thereby, saved any load shed from occurring. It might have recognized this problem by either pre-event studies that knew that under heavy loading conditions the generator could not support voltage, or by monitoring VAR flow at the generator, or by monitoring the system voltage profile. However, all the programming and system monitoring is easier said than done.

Modeling an entire power system for power flow instability is a rather involved calculation. The most complex analysis typically involves a large mathematical matrix representation of the impedances, voltages, and power flows throughout the system. The analysis typically examines the matrix looking for signature eigenvalues that are indicative of an unstable system. The eigenvalues are numbers that may be a measure of the system model sensitivity to load, generation, or line changes. For example if a small change load at a few buses makes a major change in the system load flow patterns, an unstable system is indicated. If the system matrix eigenvalue analysis was correctly written the eigenvalues would also see large changes when the loads changed, and the eigenvalues would give direct feedback about where the problem in the system was located. Similarly, an unstable condition may be indicated and found if load flow analysis is having convergence problems.

Small/Industrial Scale SCADA Implementation

In this application a PLC (Programmable Logic Controller) or similar plant operating computer monitors the power being received from the utility, as well as the power being generated locally. If the PLC sees the utility breaker open (typically by a protective relay) or detects a loss of power from the utility by some other means, it knows immediately the level of load deficiency that must be picked up by the local generation. The PLC must also know the real and reactive “spinning” reserve available from the generator. It must know how fast the generator can draw upon this real and reactive reserve, which is mainly a function of the generator’s governor and excitor response times. A properly programmed PLC can derive from this information what load shedding actions it must take to ensure the maximum survival of the plant for the loss of the tie to the utility at any given moment. An example of this approach is provided in reference [22].

In this application there is generally little obvious preemptive action that the load shedding PLC can perform before a system upset occurs. However, the PLC does have some pre-event work to do. It should know continuously before the event what it will do if called upon to act in the next moment of time. At a minimum this likely entails the PLC constantly knowing the present available generation (MW rating that can be picked up within maybe a second after the loss of the utility) and the present plant load. For a simple system with few operating modes this might be sufficient and the PLC logic may approach a level that hardwired logic could handle. The decisions to be made may be as simple as, “If the utility is lost, the generator is on line, and pre-trip load import level is above 1MW, always shut down grinding motors A and B.” For complex systems with many modes of operation the PLC implementation could become involved and expensive. It might become necessary for the PLC to continuously monitor the condition of the entire facility, including the power flow in many breakers and motor starters. The PLC must then be programmed with the logic required to let it know continuously for any given generating level, power loading, and plant operating condition which loads it should trip first and which loads it should not trip at all costs.

Note that the load shed system is designed for rapidly changing system conditions in a situation requiring a fast response. A definition of “fast enough” requires the same analysis as that for frequency based load shedding. Generally when a major overload occurs suddenly on an isolated generator, if the generator system is to survive, load must be shed or the generator must have a reserve that can be accessed in a timeframe that is measured in fractions of a second to a couple of seconds. Hence, a fast response from the PLC is required.

If the PLC can react instantaneously to the loss of the utility, this system actually can have some advantage in speed over the frequency based relay system. The PLC starts to react the moment the utility connection is lost, just as the overload has begun, but frequency relaying responds a short time after the overload has begun, when frequency has already decayed.

Current and/or Power Monitoring

Current (and/or power) monitoring is basically monitoring for overheating of specific equipment using an I^2R approach. If current rises above the full load amps for an extended period there is indication of a damaging overheating. Overcurrent load shedding is not typically thought of as a load shedding function, since it is usually protecting a specific piece of equipment against faults rather than protecting a power system as a whole. It removes equipment from service rather than removing the load that caused the overloading condition. As typically applied, overcurrent relaying only loosely fits into the definition of load shedding.

Discussion

Ignoring the role of overcurrent protective relays for now, the extent to which overcurrent or power relays are installed specifically for load shedding is fairly low. One reason is that due to the short term overload capability of most equipment, the relays may serve best as alarms to operators rather than as automatic load shedding devices. Another reason is that the load that is the eventual source of the overload of a given piece of equipment may be quite remote from the relay, and manual load transfer to another source may be a better solution than shedding the load.

Overcurrent relays may have a role in supervising other load shedding relays. For instance, in some situations it may be advisable to supervise an undervoltage load shedding relay with an overcurrent relay to give added security that the undervoltage condition is due to an overload condition or to only trip a line when power flow is in a given direction.

Some multifunction overcurrent protective relaying has overload monitoring capabilities. The alarm output of the relay may, in turn, be fed to a SCADA system. The slow movement of the effects of heating in most equipment allows manual load shed or load reassignment at this point by operators.

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David J. Finley received his BSEE degree from the University of Illinois in 1977. Since graduation he as worked for Illinois Power Company in the protective relaying and the nuclear plant startup areas. David is presently a Senior Engineer in the Control and Relay group of the Engineering and Technical Services Department. He has been a member of IEEE for 24 years and is a Registered Professional Engineer in Illinois.

John Horak is an Application Engineer for Basler Electric, supporting the Basler protective relaying and static excitation equipment line. Prior to joining Basler in 1997, John spent nine years with Stone and Webster Engineering. While with Stone and Webster he was on assignment for six years in the System Protection Engineering unit of Public Service of Colorado where his duties included short circuit and relay coordination studies, equipment and outage troubleshooting, and creating detailed relaying and control design. The remainder of his time with S&W he was assigned numerous tasks associated with short circuit, relay coordination, and load flow studies in industrial facilities. Prior to joining S&W he spent a net time of three years with Chevron and Houston Light and Power. He earned a BSEE from the University of Houston and an MSEE in power system studies from the University of Colorado in Denver. John is a member of IEEE PES and IAS and a Professional Engineer in Colorado.

If you have any questions or need
additional information, please contact
Basler Electric Company.
Our web site is located at:
http://www.basler.com
e-mail: info@basler.com

Basler Electric Headquarters
Route 143, Box 269,
Highland Illinois USA 62249
Phone +1 618.654.2341
Fax +1 618.654.2351

Basler Electric International
P.A.E. Les Pins, 67319 Wasselonne
Cedex FRANCE
Phone +33 3.88.87.1010
Fax +33 3.88.87.0808