

## **Voltage Collapse Mitigation**

### **Report to IEEE Power System Relaying Committee**

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## I. Introduction

Proper application of protective relaying and control schemes and other remedial actions can reduce the probability of voltage collapse. The IEEE Power System Relaying Committee (PSRC) decided to review the factors affecting the choice and application of protection and control schemes, to assist relay engineers in making their contribution to the design of reliable power systems.

In January 1994 the PSRC produced a special publication [1] discussing the phenomenon and describing various automatic load shedding schemes. During the preparation of that publication it became apparent that there were a number of protection and control strategies that could be applied to reduce the probability of voltage collapse. This report discusses the protection aspects of the various schemes, and factors affecting their application. By pointing out relay highlights and concerns, it will supplement a more comprehensive reference [2].

Voltage control problems are not new to the utility industry but the problems in the past were primarily associated with the transfer of power from remote generation sites to load centers. These problems were addressed by specific control and/or protection schemes dedicated to the particular transmission systems.

More recently, the combined effects of inter-utility power transfers, wholesale wheeling, interconnection of NUGs and difficulty in building new transmission facilities have resulted in operating transmission systems closer to their voltage/reactive limits. Voltage control problems are now appearing in more tightly meshed transmission systems and over wide areas. Maintaining adequate network voltage with reduced transmission margins has become a major source of vulnerability for many interconnected systems.

The phenomenon of voltage collapse has created significant interest and much research. The major issue in dealing with voltage collapse is the

proper diagnosis of the underlying factors causing low voltage. Proper coordination of protective schemes and system controls during declining or low voltage conditions is essential.

## II. Voltage Collapse

### A. Introduction

The main symptoms of voltage collapse are - low voltage profiles, heavy reactive power flows, inadequate reactive support, and heavily loaded systems. The collapse is often precipitated by low-probability single or multiple contingencies. The consequences of collapse often require long system restoration, while large groups of customers are left without supply for extended periods of time. Schemes which mitigate against collapse need to use the symptoms to diagnose the approach of the collapse in time to initiate corrective action.

The following subsections will discuss the modeling of the collapse (required in order to determine the symptoms) and techniques to use the symptoms to make the diagnosis. More information on modeling systems subject to voltage stability concerns are available in [3].

### B. Modeling of Voltage Collapse

Modeling techniques can be divided into two main categories, static or dynamic. In determining the suitability of the different approaches, it is important to distinguish between various events which affect the speed and probability of voltage collapse:

- disturbances of topology, which may involve equipment outages, or faults followed by equipment outages. Many of these disturbances are similar to those which are traditionally associated with transient stability analysis, and sometimes the distinction is hard to make. For analysis of these events, a dynamic system model is required.
- load disturbances; these are the fluctuations of load which may have dynamics of their own, which can be split into

- slow load fluctuations (normal random load fluctuations)
- fast load fluctuations (such as outages of large blocks of loads)

Slow load fluctuations may be treated as inherently static. They cause the stable equilibrium of the system to move slowly, which makes it possible to approximate voltage profile changes by a discrete sequence of steady states rather than a dynamic model.

The following table briefly summarizes the types of disturbances which may cause voltage instability and the appropriate modeling approach:

Disturbance	Description of Disturbance	Model
Topological	Equipment Outage	Dynamic
	Fault	Dynamic
Load Fluctuation	Fast	Dynamic
	Slow	Static

While the three types of disturbances which require dynamic analysis are also known as the leading causes of other types of transient instability, they may cause voltage instability if either one of the following happens:

- the post-disturbance equilibrium has a low voltage profile
- the transient voltage dips during the disturbance are too long
- the post-disturbance equilibrium is voltage unstable (i.e., adding reactive power support at any bus lowers the voltage at the same bus)

The best way to identify all the aspects of transient and/or steady state performance of the system before, during, and after the disturbance, as well as the effects of various contingencies, is by time-domain simulation. This, unfortunately, is sometimes a computationally expensive way.

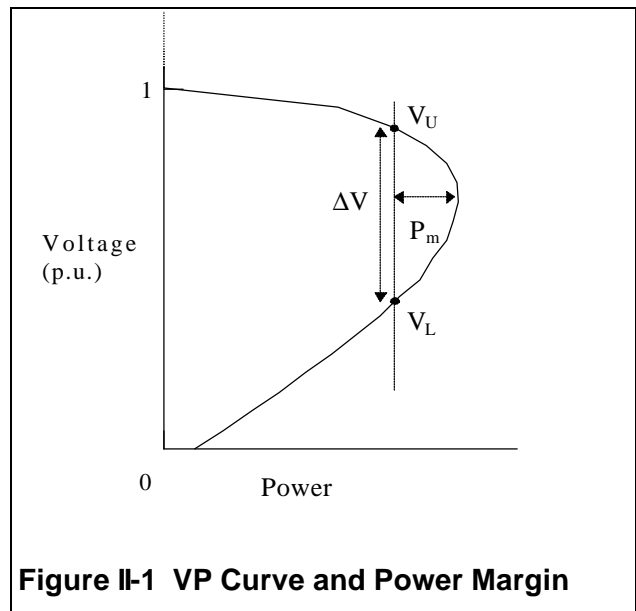
### C. Voltage Collapse Proximity Indicators

Presently, static simulations are still widely used for planning and operating purposes to determine

reactive support requirements and system loading capability. However, time-domain simulations may also be used for voltage stability analysis. Following is a brief account of proximity indicators of steady state voltage instability.

Historically, early attempts to investigate voltage unstable conditions were based on attempts to improve the solution of static load flow programs applied to heavily loaded power systems having low voltage profiles. It was difficult to arrive at load flow solutions for such systems because at the point of voltage collapse (and at higher loads) there is no real steady state solution to the load flow. Later, the dual solution (with two different voltages for the same power delivered) were observed to converge to a single point beyond which it became impossible to solve the power flow.

Early indicators used the distance of the two solution points as an indicator of proximity to collapse, since this distance decreases as the point of maximum loadability approaches. Figure II-1 shows a VP diagram of a particular system at a particular operating point, with the two solution points.



**Figure II-1 VP Curve and Power Margin**

The upper point  $V_U$  is the normal operating point, but a solution at  $V_L$  is also possible. It can be seen that the distance between the two solutions

$\Delta V$  tends to zero as the margin of power  $P_m$  between the operating point and the point of maximum power approaches zero.

VP curves do not take into account the reactive power component of the load. To include the reactive component, a third dimension must be added, as shown in Figure II-2 following.

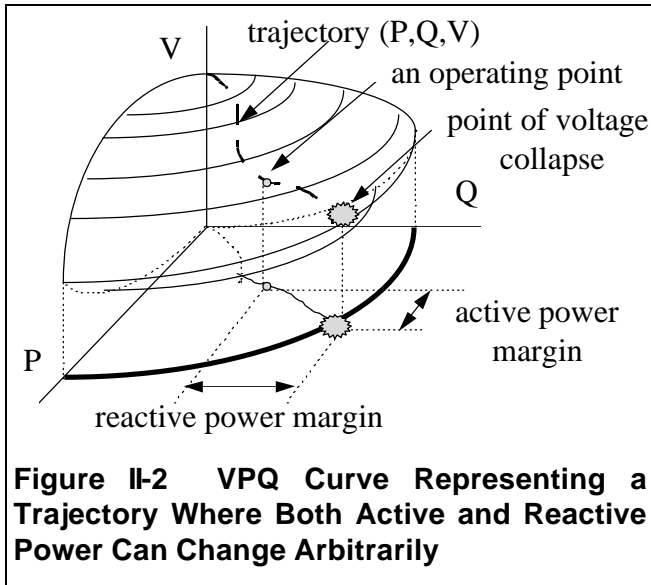


Figure II-2 represents a trajectory of the load increase when active and reactive power can change independently, as well as the active and reactive power margins. The voltage stability boundary is represented by a projection onto the PQ plane (a bold curve). It can be observed that: (a) there may be many possible trajectories to (and points of) voltage collapse; (b) active and reactive power margins depend on the initial operating point and the trajectory to collapse.

There have been numerous later attempts to use these initial observations and find more refined and accurate voltage collapse proximity indicators. They are usually based on measurement of the state of a given system under stress and derivation of certain parameters which indicate the stability or closeness to instability of that system.

Parameters based on measurement of system condition are useful for planning and operating purposes to avoid the situation where a collapse

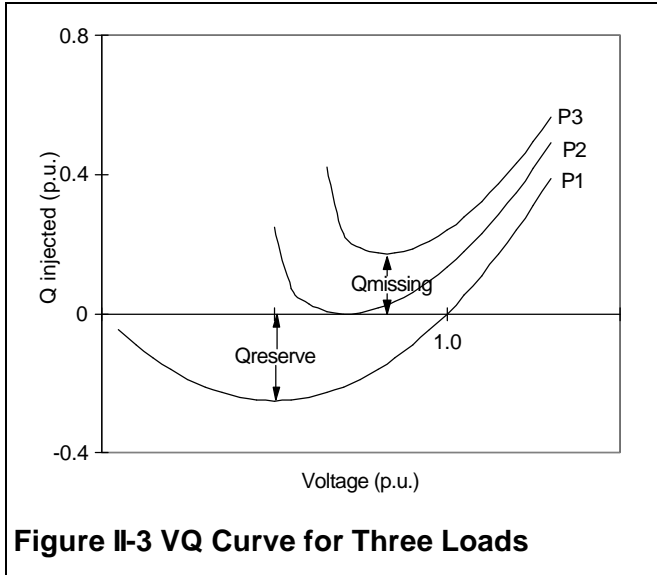
might occur. However, it is difficult to calculate the system condition and derive the parameters in real time. Rapid derivation and analysis of these parameters is important to initiate automatic corrective actions fast enough to avoid collapse under emergency conditions which arise due to topological changes or very fast load changes.

It is much better if a few critical parameters that can be directly measured could be used in real time to quickly indicate proximity to collapse. An example of such indicator is the sensitivity of the generated reactive powers with respect to the load parameters (active and reactive powers of the loads). When the system is close to collapse, small increases in load result in relatively large increases in reactive power absorption in the system. These increases in reactive power absorption must be supplied by dynamic sources of reactive power in the region. At the point of collapse, the rate of change of generated reactive power at key sources with respect to load increases at key busses tends to infinity.

The sensitivity matrix of the generated reactive powers with respect to loading parameters is relatively easy to calculate in off-line studies, but could be a problem in real-time applications, because of the need for system-wide measurement information. Large sensitivity factors reveal both critical generators (those required to supply most of the newly needed reactive power), and critical loads (those whose location in the system topology imposes the largest increase in reactive transmission losses, even for the modest changes of their own load parameters). The norm of such a sensitivity matrix represents a useful proximity indicator, but one that is still relatively difficult to interpret. It is not the generated reactive power, but its derivatives with respect to loading parameters which become infinite at the point of imminent collapse.

Other useful indicators that can be directly measured are the power margins themselves - they can be defined as margins of active, or reactive power on a single bus, or a collection of

busses in the system when a restricted number of load parameters are allowed to freely change.



For example, Figure II-3 shows a VQ diagram of a bus in a particular power system at three different loads, P1, P2, and P3. The y axis shows the amount of additional reactive power that must be injected into the bus to operate at a given voltage. The operating point is the intersection of the power curve with the x axis, where no reactive power is required to be injected or absorbed. If the slope of the curve at the intersection is positive, the system is stable, because any additional reactive power will raise the voltage, and vice versa. It can be seen that the system is voltage stable with the lightest load, P1. For this load, there is a reserve of reactive power ( $Q_{reserve}$ ) that can be used to maintain stability even if the load increases. The system is only marginally stable with the medium load P2. The system is not stable with the heaviest load P3, since an amount of reactive power ( $Q_{missing}$ ) must be injected into the bus to cause an intersection with the x axis. Thus the measure of  $Q_{reserve}$  gives an indication of the margin between stability and instability.

Although  $Q_{reserve}$  may be difficult or impossible to measure directly, some means of estimating it are available. One method is to find dynamic sources (or a single lumped source) of reactive power that play a significant role in supporting the

voltage in a specific area that may be subject to voltage collapse. Power flow studies will show how these sources respond to voltage depressions in the region of interest. When studies have defined the relationship of the Var reserve in these specific sources, to total Var reserve in the region, it may be possible to use the Var reserve of these sources as an indicator of total Var reserve in the region. Another method may be to compute the significance of all dynamic sources in the region, measure their unused Var capability, and compute the amount of  $Q_{reserve}$  available to the region of interest.

Important aspects to consider in voltage stability analyses:

- Operating limits, such as reactive power generation limits, are important factors in voltage stability analysis. An example of the application of such limits follows in the discussion on conventional indicators.
- Many loads (especially the composite loads, as viewed from the transmission network), are sensitive to voltage, and the effects of their voltage-related behavior are to be accounted for in accurate analysis of voltage stability. Load characteristics are discussed later in this paper.
- Accurate short-term load forecasting techniques are to be used in order to assess the most likely direction of the load changes and corresponding margins.

#### D. Conventional Indicators

System planning static loadflow studies, can define possible scenarios. For example, recent transmission network assessments conducted by the reliability regions which compose the North American Electric Reliability Council (NERC) indicate that portions of the regional transmission networks continue to be loaded to their limits when accommodating power transfers. Special operating procedures are in place to coordinate transfers and maintain system reliability during contingency conditions. In the Eastern Interconnection, reliability of the transmission

system will continue to be maintained through the use of operating procedures such as the Reliability Coordination Plan (RCP). The RCP was developed by utilities owning and operating the transmission systems in various North American regions. It is used to curtail or limit transfers to insure adequate voltage profiles in that part of the Eastern Interconnection.

Some common indicators of system conditions that are presently measured to determine an emergency system state, requiring voltage collapse mitigation actions are

- Tie line status, generator status
- Voltage, time
- Reactive power limiters in action
- Reactive power reserves.

These indicators may be used individually, or together to determine the need for automatic action. The status of tie lines or important local generators can be a very good indicator, if their presence is required for stable operating conditions. Such indicators cannot normally be used by themselves however, since voltage collapse is a system wide phenomenon which cannot be described by knowledge of local conditions alone. To allow use of a scheme looking at the status of the critical equipment, manual arming and disarming by system operators may be required. This would place extra burden on system operators however, and results in less than optimum arming of the mitigation scheme. Thus the status of equipment can be considered as one part of the indication of impending collapse. Other important factors like tie line loads or reactive power source outputs may be combined with equipment status to make the decision. The Florida Power and Light scheme [4] is one such scheme that uses a combination of equipment status and other factors.

Low voltages over a period of time are widely used in undervoltage load shedding schemes and load tap changer control schemes (as will be discussed later in this report). A significant limitation of localized voltage measurement is that

there is no guarantee that low voltages persist over a complete region. In spite of this, such schemes have been operating reliably for many years [1,5], in the sense that they have been secure against undesirable operation, and have provided load relief under low voltage conditions. However, it is a rare condition to be in danger of imminent voltage collapse; so experience under a wide variety of system conditions is not available.

When reactive power limiters on generators or synchronous condensers operate to maintain the machines within their capability, these machines cannot do any more to support system voltages. Thus the operation of the limiters may be good indicators of impending collapse. Such indicators are not yet widely used in North America, but are more frequently used in Europe.

Exhaustion of reactive power reserves is similar to operation of reactive power limiters because the result is an inability to maintain voltages. Exhaustion of such reserve means that one of the margins mentioned above as a direct indicator of the proximity of collapse has decreased to zero. When system studies define the critical reserves, and levels, measurement of remaining reserves can give a dependable warning of the approach of voltage instability. At least two utilities in North America (BC Hydro and Florida Power and Light) use reactive power reserve as one factor in arriving at a decision to shed large blocks of load [1,4]. Measurement of reactive power reserve is discussed later in this paper.

### ***E. Future possibilities***

Some recently developed relaying techniques may be useful in providing indication or control action in near voltage collapse conditions. Following are some examples of these new developments.

- Adaptive relays can change settings as system conditions change. To cope with voltage problems, the shedding of load is based on voltage measurements, and is initiated when the local voltage falls below a certain setting. The setting, location, and

amount of the load to be shed should be changed to adapt the load shedding scheme to the varying system conditions. The protection against voltage instability can be designed as a part of the hierarchical structure. Decentralized actions are performed at substations with local measurements which may be modified by measurements or decisions from a wider area, using a communications system. Better decisions can be made at a higher hierarchical level, but larger number of relevant system measurements are required.

- Phasor measurements are useful to speed up state estimation to determine collapse in real time fast enough for automatic action. Instead of using a relatively slow communication with conventional SCADA, one can envision using faster communication links with phasor measurement units which do not require much post-processing of measurement data, and could possibly be used for real-time control of some transients in power networks. Phasor measurement units, and similar high-speed measurement devices are a predecessor of a new, faster, and more sophisticated generation of data acquisition devices for system-wide monitoring in near real-time conditions for a variety of disturbances, including voltage instabilities.
- User definable relays [6,7] may be useful for special applications where unique measurements are required. For instance, they may be set for specific rate of change of voltage, if rate or shape of voltage collapse can be defined. User configured relays may discriminate between collapse due to instability and depression due to fault or motor starting. They may also be used in measurement of reactive power being used for voltage support, as a percentage of maximum available reactive power.

#### **F. Time Frame of Voltage Collapse**

Voltage collapse can occur over a wide variety of time frames. Loss of voltage stability generally

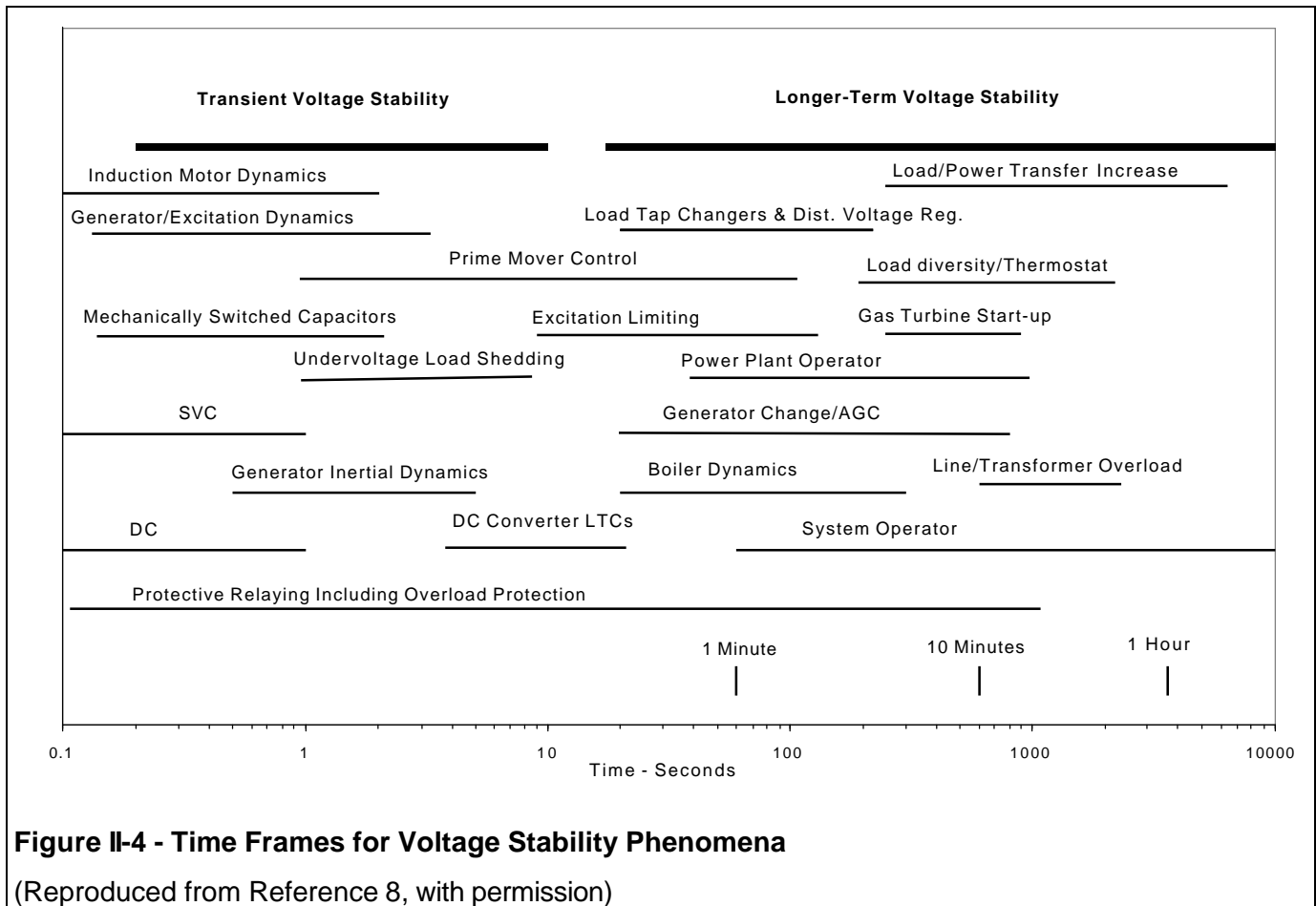
results in aperiodic decreasing (but sometimes increasing) voltages. Figure II-4 shows some of the time frames of the various phenomena involved in loss of voltage stability. It can be seen that several orders of magnitude of times are involved.

Voltage stability phenomena in the transient region are often closely involved with angular stability phenomena. Low voltages can result in loss of angular stability, and loss of angular stability will result in fluctuating voltages. Voltage collapses in the longer-term time frames can also result in loss of angular stability. Voltage collapses do not always result in loss of angular stability however. Even collapses in the transient time frame, such as may be precipitated by slowly cleared short circuit faults do not necessarily result in loss of angular stability.

Voltage collapses in the longer time frames are the type that are attracting much of the attention and recent research in power system phenomena. Tools to study time dependent system response in longer time frames have only been relatively recently developed, while tools for transient analysis of power systems are very mature and widely used. Advances in numerical algorithms and computer power have made it possible to simulate systems of very large size and with many types of equipment. Several software tools are now available to perform simulation of power system responses over a long period of time. Examples are the EPRI's ETMSP [8], EUROSTAG, and PSS/E. Measures to avoid collapses in all time frames will be discussed in this paper. The time frame of the voltage instability phenomenon is an important factor in application of mitigation measures.

Voltage collapses in the transient time frame are most often caused by slowly cleared faults, such as the cascading collapse on 22 August, 1987 that TVA experienced [9], and the significant voltage depression that Philadelphia experienced on July 1, 1992 [10].





Collapses in the longer term time frame may result from loss of significant sources of local generation or reactive support, or from loss of heavily loaded transmission capability. In such cases, transient overload capability may allow nearby generators to maintain voltages for a short time, until maximum excitation limiters come into effect and local Var support is severely curtailed. However, loss of significant reactive power support can also lead to loss of angular stability and voltage collapse in the transient time frame as was the case in the 13 March 1989 collapse of the Hydro Quebec system due to loss of several critical SVCs that were supporting the transmission system voltages.

Collapses in the long term time frame may also be caused by unusually fast load build up (such as the Tokyo 23 July, 1987, incident). They may also be caused by changing over time, of the characteristic of the load sensitivity to voltage (as

discussed in the following section). Thus a loss of a significant source of local generation or reactive support can precipitate a voltage collapse in the transient, or long term time frame.

### G. Load Types

Load modeling is an essential, but often inadequately represented element in power system studies. Given a power system topology, the behavior of the system following a disturbance, or whether voltage collapse can occur, depends to a great extent on how the load is represented.

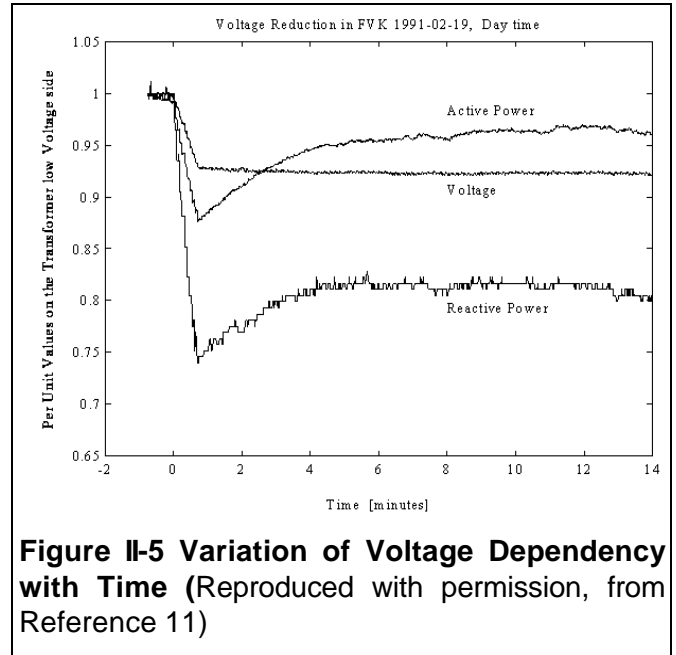
Load admittances are a function of voltage and frequency. The characteristics of load with respect to frequency are not critical for the phenomena of voltage stability, but the characteristics with respect to voltage are critical. Systems with "soft" loads which decrease sharply

with voltage are much more likely to be voltage stable than systems with “hard” loads that are relatively independent of voltage. The relationship of power to voltage may be expressed as  $P = K_p V^\alpha$  where  $P$  is the power delivered to the load,  $K_p$  is a constant,  $V$  is the magnitude of the supply voltage and the exponent  $\alpha$ , determines the sensitivity of the load to voltage. “Hard” loads would have values of  $\alpha$  near 0, and “soft” loads would have values nearer 2.

Not only is the characteristic of the real power component of load (with respect to voltage) important, but also the reactive power component characteristic is important. Voltage magnitude is much more sensitive to reactive power flow than to real power flow. Similar to the case of real power, the reactive power sensitivity may be expressed as  $Q = K_q V^\beta$ , where  $Q$  is the reactive power supplied,  $K_q$  is a constant,  $V$  is the voltage magnitude and the exponent  $\beta$  determines the sensitivity to voltage. Investigations into the sensitivity of load with respect to voltage must address both the real and reactive components (they must attempt to determine the values of  $\alpha$  and  $\beta$ ).

The values of  $\alpha$  and  $\beta$  are not necessarily constant with time. Since voltage collapse is a dynamic event, the dependence of  $\alpha$  and  $\beta$  with respect to time is also important. A common method of investigating load characteristics is to measure the response of load to small voltage changes. The studies often show that the characteristics of  $\alpha$  and  $\beta$  with respect to time are different from each other.

Figure II-5 shows test results from a Swedish study (at a substation designated FVK). For this figure, the initial values of  $\alpha$  and  $\beta$  vary from about 2 and 5 respectively, to 0.2 and 4 in the steady state.



**Figure II-5 Variation of Voltage Dependency with Time** (Reproduced with permission, from Reference 11)

In generating data for load models, there are two approaches: measurement-based, and component-based. Measurement-based data are derived from curve fitting the field measurements [11,12,13,14]. Component-based methods are used when physical measurements are not available. EPRI has a program LOADSYN that provides an automated means to generate parameters for the mathematical load model. The user needs to specify load classes, such as percentages that are residential, commercial, industrial, and components within each classes such as heating, lighting, etc. More details can be found in [15,16].

Since customers require good power quality, it is not usually possible to measure the response of loads to large voltage changes (more than a few percent), such as may occur in a loss of voltage stability event. The validity of load dependency tests must therefore be estimated for larger voltage fluctuations. That is, it is not certain that the quantities for  $\alpha$  and  $\beta$  are valid for voltage variations outside tested levels.

The effectiveness of a type of control or protective action to mitigate against voltage collapse depends significantly on the load type. For instance, a common control action (which will

be discussed later in this paper) is voltage reduction by load tap changer blocking or set-point change. Such a control action will be much less effective for hard loads than soft loads. The period of effectiveness will also depend to a large extent on the variation of the exponents  $\alpha$  and  $\beta$  with respect to time.

### III. Dynamic Sources of Reactive Power

#### A. Static Sources

Adequate Var support is critical to maintaining healthy system voltage and avoiding voltage collapse. Within limits, static reactive sources such as shunt capacitors, can assist in voltage support. However, unless they are converted to pseudo dynamic sources by being mechanically switched, they are not able to help support voltages during emergencies, when more reactive power support is required. In fact, shunt capacitors suffer a serious drawback of providing less reactive support at the very time that more support is needed, during a voltage depression (Var output being proportional to the square of the applied voltage).

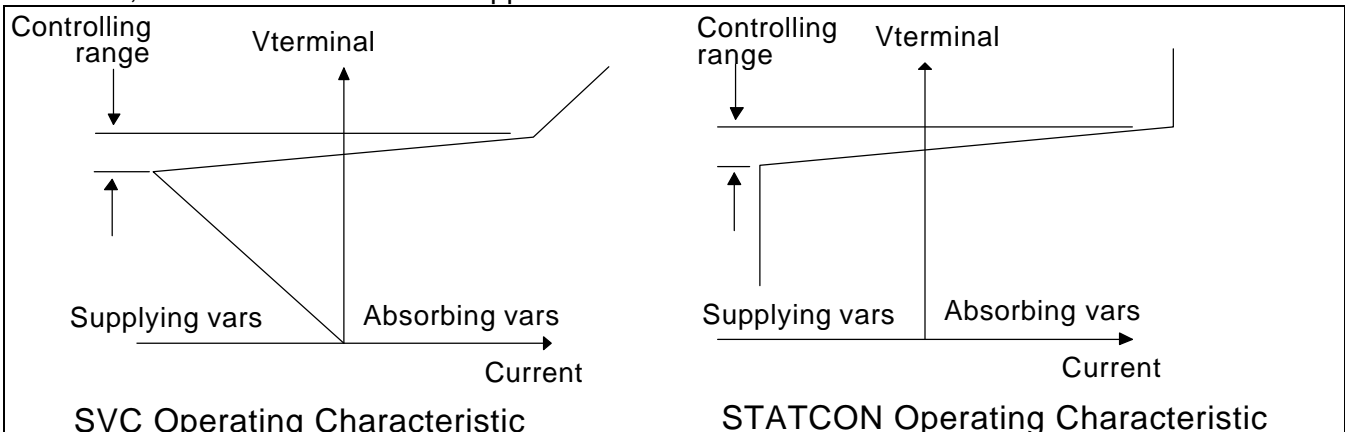
Capacitors can be switched infrequently at high speed to provide dynamic voltage support, as discussed in Section [IV]. However, the control schemes can become rather complex, and large blocks of capacitance must be switched at each stage in a control scheme. More smoothly controlled, and faster reactive support than

mechanically switched capacitors can be provided by true dynamic sources of reactive power such as static Var compensators (SVCs), static condensers (STATCONs), synchronous condensers, and generators.

The application of SVCs and STATCONs in the context of voltage stability is discussed in recent literature[2]. The main differences between these two devices is that the SVC becomes a shunt capacitor when it reaches the limit of its control and all capacitance is fully switched in. Its reactive power output decreases as the square of the voltage when the maximum range of control is reached. The STATCON output is limited by its current carrying capability. Therefore, its reactive power output decreases linearly with the terminal voltage when the maximum range of control is reached. Figure III-1 compares the operating characteristics of the SVC and STATCON.

In respect to its capability to deliver more reactive power output than an SVC at lower voltages, the STATCON behaves more like a synchronous condenser than an SVC. Short time overload capacity of the STATCON is much lower, and of shorter duration than that of a synchronous condenser however.

It can be seen from this figure that in the case of the SVC, after the voltage drops to a level where maximum reactive capability of the equipment is reached, any further decrease in voltage results



**Figure III-1 Comparison of SVC and STATCON operating characteristics**

in severe decrease in supplied reactive current. However, the current supplied by the STATCON remains at the maximum value, even in the presence of continued voltage decline. The slope of the characteristic in the controlling range is caused by deliberate droop in the control characteristic for stability. The SVC will of course be limited by the short time current capability of the reactors when the terminal voltage rises above the controlling range. In practice excessively high voltage will not be allowed to persist on the power system for long enough to damage the reactor (or reactor protection will operate to disconnect the SVC).

SVCs and STATCONS are often operated in conjunction with static sources of reactive power such as reactors or capacitors. The SVC or STATCON control equipment can be designed to switch the static sources in such a manner as to keep the dynamic source as close as possible to the middle of its operating range. By switching static sources in this manner, as much as possible of the full dynamic capability will be retained. An example of switched capacitors being used to maximize the availability of dynamic power from a group of synchronous condensers is given in Section IV-A.

Control of SVCs and STATCONS will normally be achieved by use of digital control devices with almost unlimited flexibility to provide appropriate control of terminal voltage within the capability of the primary equipment. Protective devices applied to this equipment will of course have to coordinate with control settings and equipment capability. This coordination is normally thoroughly checked at commissioning as the rated output of the device is measured as part of acceptance testing, and at routine maintenance intervals.

## B. Synchronous Machines

### 1. Capability Diagram

A synchronous machine is capable of generating and supplying reactive power within its capability limits to regulate system voltage. For this reason, it is an extremely valuable part of the solution to

the collapse-mitigation problem. Synchronous machines considered in this paper may be generators or synchronous condensers. In terms of reactive output capability, synchronous condensers are treated similarly to static Var sources during commissioning and maintenance in that rated output power must be demonstrated to be achieved.

Generators however are rated for specific real power output, usually at a specific power factor. During commissioning and maintenance, real power output is carefully checked to meet specified requirements. Reactive power output may be checked during commissioning, but may not be carefully checked after that. The reactive power capability may be required by the system, but is not considered to be a revenue generator. Due to large impact on the system voltages, it may be difficult to operate large generators at their reactive capability limits (for test purposes). Therefore coordination of protection with control devices is not so frequently checked as with other reactive power sources[17]. Numerous voltage collapse or near collapse incidents have been aggravated by unexpected loss of healthy generators due to lack of coordination of protective equipment with generator capability.

A typical generator capability diagram as supplied by a manufacturer of a 165 MW, 0.9 pf turbo generator is shown in Figure III-2 following.

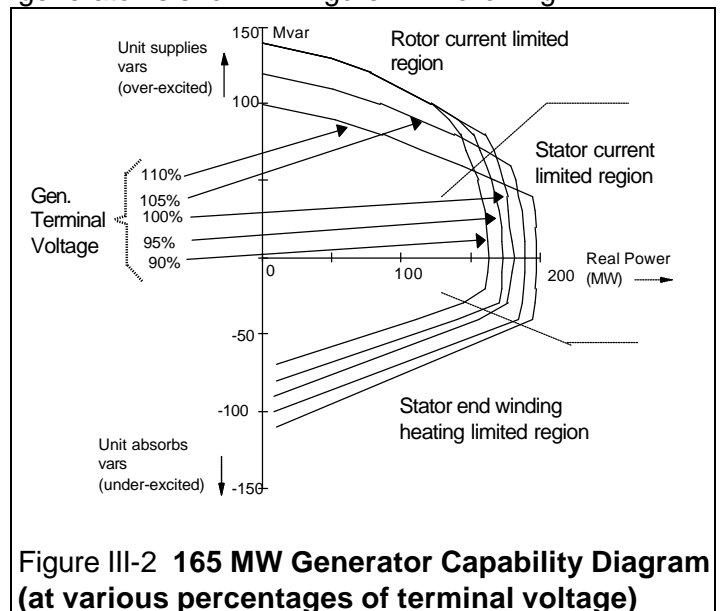


Figure III-2 165 MW Generator Capability Diagram (at various percentages of terminal voltage)

Some interesting observations can be made from Figure III-2. The reactive power capability increases dramatically as real power output is limited. Further, the amount of reactive power available from the generator is very dependent on terminal voltage. In this respect, a generator operating at low real power output can supply significantly more reactive power at low voltages than at high voltages.

The increase in reactive power capability at lower real power output means that system planners and operators may choose to generate less than rated real power in order to have more reactive power from generators at critical locations in voltage stability threatened systems. The choice of operating point (Mw versus Mvar) for generators at critical locations is predetermined, and not usually subject to automatic control. It should be noted that when the generator reaches the limit of its capability, particularly in the rotor current limited region, it may not be controlling its terminal voltage. The fact that it is at its limit of capability means that it is not able to raise the terminal voltage to the reference setting of the voltage regulator. Thus the reactive power limits are to a certain extent, determined by the system conditions, and independent of the generator excitation system.

The value of a generator as a source of reactive power can be separated from its value as a source of real power, if it can be decoupled from the turbine and run as a synchronous condenser. In some plants where fuel or operating costs may make power generation uneconomic, it may be possible to convert the generator to a synchronous condenser, and use it to support voltages in an area where real power has to be imported from a remote area.

The generator capability diagram as supplied by the manufacturer is not necessarily the capability of a given generator connected at a given point in a system. Many other factors such as auxiliary equipment voltage limits, stator or transformer winding voltage limits, cooling medium conditions, or over and under excitation controllers can limit a given generator's capability to significantly less than that indicated by the manufacturer's

diagram. Reference[18] describes in more detail the various other factors that can limit the generator capability.

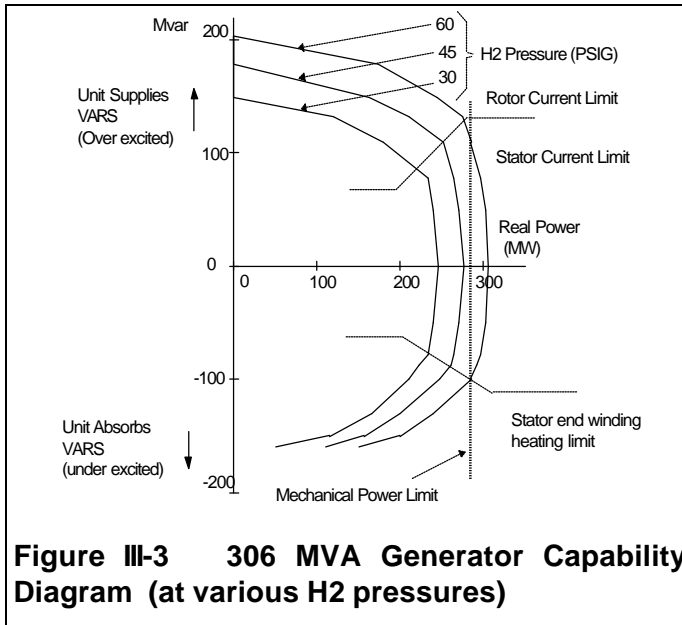
Another significant limiter, which does not always coordinate with the generator capability or control equipment settings is the generator protection. Rotor overload protection, loss of field protection, and backup protection are all systems that can cause unexpected and undesirable disconnection of a generator in a voltage stressed system. Later sections in this paper will discuss some of those protection aspects in more detail. A major reason for unexpected operation of protective devices is the lack of routine exercising of the generator at its capability limits [17].

Excitation power is supplied by one of two types of exciters, rotating and static. As the term implies, a rotating exciter is one that mounts on the machine shaft and rotates with the generator producing main field current by induction. The exciter's field is energized by some independent source, e.g., a permanent magnet generator (PMG), station battery, etc., controlled by the voltage regulator. A static exciter is comprised of a power transformer and power electronics utilizing generator terminal voltage as the source of field power. It would appear that a static exciter would be limited in its capability like switched capacitors or an SVC because it is dependent upon the generator terminal voltage for power; however, the transformer ratio is selected so that the power electronics can deliver a broad range of field current even with depressed voltage. Generally speaking, static exciters are quicker in their response to voltage disturbances than their rotating counterparts because of the latter's additional windings and their associated time constants.

## **2. Effect of Cooling Medium on Var Capability**

Generator capability may depend significantly on the type and amount of cooling. This is particularly true of hydrogen cooled generators where cooling gas pressure affects both the real and reactive power capability. The curves shown in Figure III-2 are for an air cooled machine, operating at maximum ambient air

temperature of 40 degrees C. Figure III-3 below shows the variation in capability of a particular 306 MVA hydrogen cooled generator (at 100% terminal voltage). The mechanical power supply capability is superimposed to show the limitations of the steam supply system. The way in which reactive power capability increases with hydrogen pressure is easily seen.



There are some practical issues that warrant serious consideration before increasing hydrogen pressure to increase reactive power supply capability.

First, it is important to check with the generator manufacturer to ensure that the capability curves furnished with the unit reflect that particular unit's design and are not "generic" for units of that type and size. Although the generator itself may be capable of the heavier Var duty, the auxiliary systems supporting the generator and cooling system may not be.

Second, higher hydrogen pressure generally means increased hydrogen leakage. Depending upon the integrity of the hydrogen seals, this may or may not be a problem. However, the risk of explosion because of dangerous hydrogen concentrations increases as leakage increases. The seals, hydrogen pressure regulators, heat exchangers, etc. all need to be able to operate at

the higher pressure. In addition to design differences, the age of the unit, maintenance cycles, and relative duty all affect the leakage rate at a given pressure.

Third, it is important that the generator's hot spot temperatures be somehow monitored, either directly or indirectly. Average temperature, such as hot gas temperature, average rotor winding temperature, etc., provide some information, but these are not hot spot temperatures. Operating close to the rated capability curves necessitates having this additional information because of the potential for causing serious damage due to local heating above rated temperature. Section III D b) below discusses some techniques of rotor temperature measurement presently being investigated.

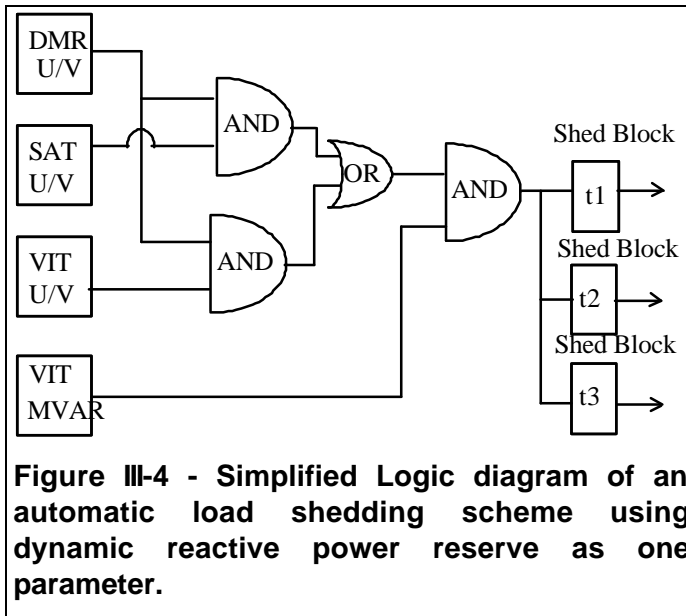
Finally, if a generator has been derated in its output for hydrogen leakage problems, it is likely that the control and protective devices have been reset accordingly. Settings of control and protective devices may have to be suitably adjusted and tested to ensure coordination with each other and generator capability before the machine can be depended upon to provide additional reactive capability.

### C. Measurement of Dynamic Reactive Power Reserve

The outputs of dynamic sources of reactive power such as synchronous condensers and generators are sometimes used in voltage collapse mitigation schemes. As discussed earlier in this paper, when these sources are operating at, or near, their maximum capability, the risk of voltage collapse is greatest. It may present a challenge to the relay engineer to measure the output of such sources as a percentage of their maximum capability. When more than one source is involved, it is necessary to determine that only in-service sources, with automatic voltage regulation capabilities are used in the calculation of percentage of dynamic reactive capability.

One scheme described in reference 1 uses the output of four strategically located synchronous

condensers (rated 2x100 Mvar and 2x50 Mvar) in conjunction with low voltages at more than one key bus to initiate a load shedding scheme. The simplified scheme logic diagram is shown in Figure III-4 following. Staged load shedding will be initiated if the output of the synchronous condensers at VIT is greater than a certain percentage of their maximum capability and the voltage is low at least at two important busses (DMR and either SAT, or VIT) in the region.



**Figure III-4 - Simplified Logic diagram of an automatic load shedding scheme using dynamic reactive power reserve as one parameter.**

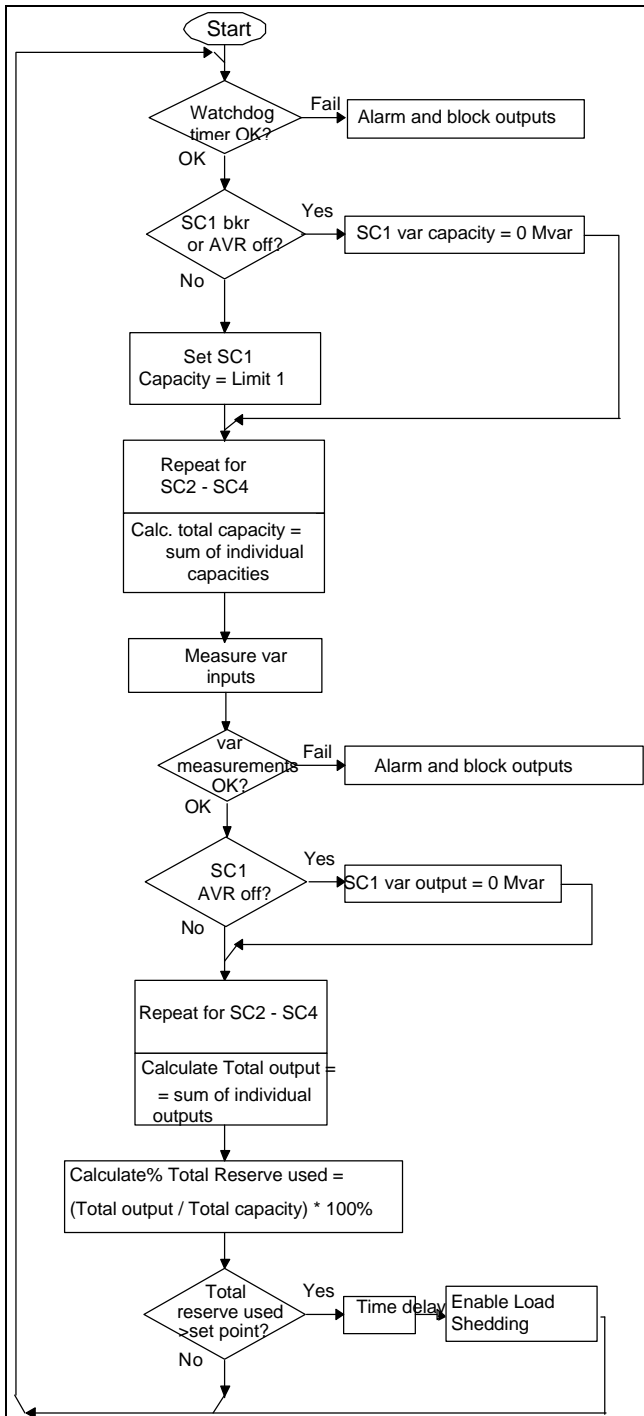
Two factors complicate the determination of percentage of available capability that is being generated by the synchronous condensers. First, the units have different excitation systems with different gains, and different speeds of response. They do not necessarily respond to transmission system voltage depressions to the same degree or in the same time frame as each other. Secondly, some of the synchronous condensers may not be in service, or may be operated in manual excitation mode, and cannot be considered as dynamic sources of reactive power during any particular instant. It was decided to consider only the output of in-service units, with automatic voltage regulators in service, and to use the average output of those units expressed as a percentage of the maximum capability of all units being considered.

A PLC was used to calculate the average output of the synchronous condensers as a percentage of maximum capability. A simplified logic diagram of the scheme implemented in the PLC is shown in Figure III-5. It should be noted that this figure has been simplified for clarity (as have all other PLC logic diagrams in this paper). PLC logic diagrams would normally include extensive error checking routines, most of which are not shown in the diagrams.

It can be seen that the status of the synchronous condenser unit breaker and automatic voltage regulator are both used to determine whether it's output should be considered as being available. The status of the voltage regulator also determines whether the output of the unit is considered as part of the reactive power being delivered.

In Figure III-5, the quantity "Limit 1" is the rated capability of the synchronous condenser. This is shown as a fixed setting in the diagram. However, some of the units may be run with or without hydrogen gas cooling. As discussed, in the previous section, the rating of the unit is higher when hydrogen cooling is available. A status input for each unit is available to change the setting of the limit depending on whether or not hydrogen is present. However, the limit is not scaled with hydrogen pressure.

For the synchronous condensers described above, the reactive output rating is relatively easy to define. However, the reactive capability of generators is very variable. Measurement of reactive power reserve available in a generator can present challenges due this variation in capability. Measurement of rotor current is one indicator, since the reactive power output of the generator (operating at less than rated power factor) is reached when the rotor current is at continuously rated level. Conversion of measured rotor current to generated Mvar presents a challenge however, due to the variation of Mvar output with real power and terminal voltage. Schemes can be designed which measure the real and reactive power output and terminal voltage to determine how much of the reactive capability is being used.



**Figure III-5 - Simplified Logic Diagram of Reactive Power Output Measurement**

Such schemes are complicated by the number of analogue inputs and calculation of limits. As complexity increases of course, the reliability of

the scheme decreases. Extensive error checking of the measuring device is important, as well as examination of failure modes and consequences of failure.

#### **D. Excitation Control Devices**

Since reactive power sources are so important to voltage stability, then the control of these sources is also critical. A discussion of various excitation control features and their effects on voltage stability follows.

##### **a) Manual vs. Automatic Control**

Modern excitation systems are controlled by one of two means: manual or automatic control systems. The term "manual control" means direct control over the generator's main field current with indirect regard to terminal voltage. This is typically done by comparing the reference field current level with a signal derived from a current-sensing resistor, or current shunt, in the leads to the generator's main field winding. Any difference results in an adjustment to the excitation until there is zero error between the two control signals. This is also sometimes called current regulation.

The term "automatic control" means direct control over the terminal voltage of the generator with indirect regard for the field current. This is typically done by comparing the reference level with a signal derived from the generator terminal voltage. Any difference results in an adjustment to the excitation until there is zero error between the two control signals. This is also called voltage regulation.

A generator under manual control cannot automatically provide dynamic support to a power system in need of more reactive power to maintain normal voltage. In this mode the generator is almost like a shunt capacitor bank in providing an amount of reactive power which is not varied continuously to regulate voltage. The most significant difference being that the generator Var output may increase slightly as the system (and generator terminal) voltage declines, where as the shunt capacitor Var output decreases as the square of the system voltage.



As for auxiliary control devices and regulators, there are typically only three active in manual mode: the minimum and maximum field current limiters and a ceiling voltage limiter. The ceiling voltage limiter acts to limit the field current to a level that corresponds to a safe terminal voltage level in the event of a sudden load rejection (this field current level is typically much less than the maximum field current limit).

In the automatic, or voltage control, mode, minimum and maximum voltage limits are active and are analogous to the minimum and maximum current limits in current control mode. In addition, there are typically an overexcitation limiter (V/Hz limiter), a minimum excitation limiter (MEL) or under excited reactive ampere limiter (URAL), reactive droop control, reactive drop compensation (also called line drop or load compensation or LDC), Var limiter/regulator, power factor limiter/regulator, and a power system stabilizer.

#### **b) Overexcitation Limiter**

An overexcitation limiter can take two forms: 1) a device that limits the thermal duty of the rotor field circuit on a continuous current basis and 2) a device that limits the effects of stator or transformer core iron saturation due to excessive generator terminal voltage, underfrequency, or the combination of both.

The overexcitation limiter protecting the rotor from thermal overload is an important controller in system voltage stability. It usually is disabled in the transient time frame to allow the excitation system to force several times the rated voltage across the rotor winding and more than rated continuous current, to help retain transient stability. After a few seconds, the limiter is activated in an inverse time function - the higher the rotor current, the sooner the limiter is activated. The limiter brings the continuous rotor current down to, or just below, rated level to ensure the rotor is not overheated by excessive current. The limiter acts without regard as to what the actual rotor temperature is. Even if the rotor was very cool before the overexcitation

event, the time characteristic of the limiter is not changed.

Several techniques are available to measure the rotor temperature, including:

- Calculation of average winding temperature by measuring the resistance (slip ring voltage divided by rotor current). This technique requires special (low current) brushes to measure the rotor voltage without being affected by voltage drop across the brushes. As discussed earlier however, the average rotor temperature is not necessarily a good indicator of hot spot temperature. Thus use of the average temperature as a control device is limited.
- Measurement of winding temperature at selected locations by resistance temperature detectors or thermocouples. This technique requires a means of getting the measured value off the rotating equipment to monitoring equipment. Special sliprings and brushes, or radio transmission may be used for this purpose. If the locations of temperature probes are carefully selected, it may be possible to get a better indication of hot spot temperatures than can be determined from average temperatures. However, close collaboration with the generator manufacturer is required to ensure hottest locations are selected. It is also not usually economic to retrofit temperature probes to existing machines. Therefore use of such probes would probably be limited to new machines.
- On salient pole generators where large portions of the rotor windings are exposed, it is possible to measure the temperature of the ends of the windings by infrared scanners mounted on the stator. These measurements will however give average temperatures of portions of the winding, and similar concerns over lack of knowledge of hot spot temperatures as for the winding resistance measurement arise. The technique does however allow temperatures of individual poles to be monitored.

Rotor temperature measurement is not yet sufficiently reliable for widespread use in overexcitation control systems. Reference [2] describes one application. It is possible that as measurement techniques mature, supplementary temperature control may be feasible to extract more reactive power from a given generator. However, concerns over operating at the limits of a generator capability (as mentioned in sub-section B.2 above) must always be weighed against possible marginal increases in reactive capability. It is likely that temperature monitoring will find its optimum application in short term overload capability.

The V/Hz limiter is a device that protects the generator stator and directly connected transformers (main power transformer and unit auxiliary transformer) from excessive flux levels (with the high flux levels being indicated by high ratio of volts to Hertz). When the windings of a generator or transformer are exposed to such a condition, the core iron saturates and magnetic flux escapes from the intended magnetic path to penetrate the surrounding structural steel where induced currents can cause excessive  $I^2R$  heating which may result in failure of the generator or transformer. The V/Hz limiter ensures that dangerously high levels of excitation do not persist. For instance, it may be required to operate to limit generator terminal voltage to a safe level under conditions of depressed transmission system voltage when the generator is producing a large amount of reactive power. The probability of overexcitation is more likely when load compensation is being applied, as the automatic voltage regulator is not regulating terminal voltage under this condition. Coordination of this control device with the V/Hz protective relay (if installed) is necessary to avoid unit trips for conditions that the limiter will safely respond to.

#### **c) Minimum Excitation Limiter**

The MEL, or URAL, reduces the probability of a generator losing synchronism with the power system due to too-low a level of excitation. It is also intended to prevent generator core end iron damage due to stator field fringing resulting from

too-low a level of excitation. The MEL needs to be carefully set, coordinating with the generator's reactive capability curve, the system's steady state stability limit, and the generator's loss of field relay. This control function is most important under conditions of high system voltage, when the generator is operating at low excitation levels to absorb the maximum amount of reactive power.

Since the MEL is only functional when the voltage being regulated is higher than the reference setting, it may not be a critical function during a voltage collapse scenario. However, when voltage stability is lost, it is possible for system voltage to rise above acceptable levels. Such a circumstance might happen if too much load is disconnected during a voltage depression, or too much capacitance is added to try to boost system voltage. In such cases, proper operation of the MEL, and its coordination with the loss of excitation protection may be critical in restoring voltage stability.

#### **d) Reactive Droop Control and Load Compensation (LDC)**

These are addressed together here because they are closely related, but have opposite effects. A control voltage that is proportional to the reactive power generated by the machine is applied to the sensed terminal voltage being supplied to the voltage regulator. With reactive droop control, this control voltage is added to the sensed terminal voltage causing the regulator to sense too high a feedback voltage, resulting in a decrease in excitation. With load compensation, this control voltage is subtracted from the sensed terminal voltage causing the regulator to sense too low a feedback voltage, resulting in an increase in excitation.

With reactive droop control, the end result is a sharing of the voltage regulation of a bus to which multiple generators are connected in parallel. Without droop, the voltage regulators would be unstable as more than one regulator would attempt to control the same voltage. The machines would just circulate large quantities of Vars, and voltage regulation would be poor. Droop is critical for generators bussed together,

but it needs to be set carefully so that adequate voltage levels are maintained. That is, too much droop will result in voltage levels unacceptably below nominal.

With load compensation, the end result is better regulation of a point in the system somewhat remote from the terminals of the machine. Without load compensation, the controlled point is the point where the terminal voltage is sensed - the point where the generator vts tap into the isolated phase bus. Load compensation moves the controlled point out closer to the main power transformer's high voltage terminals by compensating for a portion of the voltage drop that occurs across the transformer due to the loading of the generator. This must be set carefully to avoid wide reactive power swings on the machine that occur if it attempts to control voltage at a point too far away in the system, electrically speaking.

A plant with more than one generator can be made to control the voltage on the transmission system some distance from the plant by the use of joint Var control (JVC) equipment. JVC allows several generators to control the voltage at a single point without reactive power swings which would result from independent voltage control action on each of the generators. This equipment ensures that all generators take an equal share of reactive power as they attempt to control the voltage at a common point.

Compensation for at least part of the reactive drop in a generator step up transformer is one way of allowing generators to more directly control system voltage. In addition to the stability concerns, the voltage at the generator terminals must also be controlled to within acceptable limits. Given the wide variation in generator reactive power capability, it may be necessary to depend on other controllers such as the volts/Hz limiter or MEL for additional control.

#### **e) Var Limiter/Regulator**

The Var limiter acts to limit the Var loading of a generator if the output reaches its threshold. Otherwise, the regulator is free to adjust

excitation as necessary to control voltage without regard to Var swings.

The Var regulator is different from the limiter. This control feature, rather than controlling the voltage to a set point, controls the Var output of the machine to a set point. Var regulation is well-suited to a system that has a steady, baseload need for Var support.

Both of these devices have application with smaller machines ("small" relative to the connected system) because of their inability to significantly alter the transmission bus voltage, regardless of their Var loading. However, it should be recognized that when these limiters are in operation, the generator will not act to help support system voltage during emergencies.

#### **f) Power Factor Limiter/Regulator**

The power factor limiter acts to keep the power factor of a given machine within specified limits while on voltage control. This device is especially useful in situations where economic penalties are imposed for operating with a power factor outside of a published acceptable range.

The power factor regulator, like the Var regulator, controls to a specific power factor without regard for the voltage. This can be troublesome for the bus voltage as the excitation will vary, and hence the voltage will vary, with changes in generator watt loading. Again, this is more typically used with smaller generators or with large synchronous motors seeking to operate at or near unity power factor (for economic or other reasons).

The increasing penetration of non utility generators in power systems results in increasing effect of their excitation control systems on power system voltage stability. Care is required to ensure their reactive power capability is not incorrectly assumed to be dynamic, when in fact they may be operating under a power factor controller or Var limiter that restricts their reactive output to much less than the units are capable of producing.

**g) Power System Stabilizer**

Reference [19] quotes - "Modern generating units equipped with high gain voltage regulators enhance transient stability (the ability to recover from large disturbances), but tend to detract from steady-state stability (the ability to recover from small disturbances about the steady-state operating condition). Power System Stabilizers (PSS) improve steady-state stability by providing damping of power system modes of oscillation via modulation of generator excitation." So described, the PSS is a device that reduces low-frequency oscillations of a generator rotor (typically in the range of 0.1 to 2.5 Hz). Regardless of how it measures the speed changes (electrical frequency or mechanical speed), the PSS is tuned to output a control voltage that is in phase with the speed changes that acts to increase excitation if the speed change is in the positive (speed-increasing) direction and decrease excitation if the speed change is in the negative (speed-decreasing) direction. The increased excitation tightens the rotor's coupling with the power system, providing a retarding torque that tends to slow the rotor, bringing it back to nominal speed. Decreased excitation loosens the rotor's coupling with the power system, providing an accelerating torque that tends to let the rotor accelerate back up to nominal speed. The purpose of the PSS is to minimize generator "hunting" and the attendant low frequency power surges, thereby stabilizing system voltage and enhancing system stability. As larger machines have far greater impact on the system and on each other in this regard, PSS's are most effective on such large machines. PSS's are presently being fitted on many existing larger machines, and most new machines which can significantly impact low frequency oscillations.

PSS's must be correctly set with regard to their gain and phase lead parameters to avoid exacerbating the oscillation problem. There are no protective elements that the PSS must coordinate with.

**E. Protection Issues**

**1. Generator Protection Relays**

It is important that generator and auxiliary protection relays coordinate with excitation control functions. Lack of such coordination has often been a factor in voltage collapse or near collapse situations. Some critical protective relays are loss-of-field, volts/Hz, rotor overload, excitation system overload, and auxiliary undervoltage protection.

The loss-of-field relay must coordinate with the MEL on a dynamic basis as well as on a steady state basis. The time delay in which an MEL can act to limit under excitation may not be stated in exciter application guides. Under transient conditions it is possible for the operating point of a generator to suddenly enter a region beyond the MEL or loss of field protection characteristics. If the time delay of the loss of field relay is too short, or the MEL takes too long to operate, miscoordination and unnecessary loss of the generator can occur. The lack of coordination can easily be missed if the exciter gain or feedback settings are adjusted after commissioning without subsequent check of the speed of operation of the control function. Regular exercising of the generator to its MEL control point will help minimize the risk of miscoordination.

Rotor and exciter overload protections must coordinate with maximum excitation limiters, again on a dynamic basis as well as on a steady state basis. Since overload protection time delays are often somewhat longer than loss-of-field protection delays, the speed of response of the maximum excitation control is not of as great a cause of concern as that of the MEL. However, the possibility for miscoordination is still present. Exciter overcurrent protection settings may be applied with more concern about short circuit sensitivity than with rotor overload capability. Further, if such protection is provided by electromechanical relays, their accuracy around the pickup current level may not be as good as the accuracy of the overexcitation limiter. Exercising of the generator at its

maximum excitation limit is the best way to ensure coordination is maintained.

Dynamic coordination of the volts/Hz protection with the volts/Hz controller is relatively easily achieved, because their time/flux characteristics are both well defined. A point of concern can arise when the volts/Hz protection is provided by one or two definite time relays set at specific levels of volts/Hz. It may be difficult to coordinate the definite time characteristics with inverse time characteristics of the control device. It is of course also important to coordinate the volts/Hz protection with the maximum voltage regulator control voltage. The maximum voltage regulator setting may be very close to the maximum rated continuous operating voltage, leaving little room for the volts/Hz protection pick up point to fit between the two limits.

Auxiliary equipment may be protected by undervoltage relays to ensure the generator is shut down safely before any essential auxiliary equipment stalls or becomes disconnected due to low voltage. It is possible that low terminal voltage could impose a limit in the underexcited region that the MEL must coordinate with. Since the undervoltage protection would normally have a significant time delay, dynamic coordination with the MEL may not be as much of a concern as static coordination.

In spite of the difficulties in operating generators at reactive power limits, regular testing of the coordination of protection and control devices at those limits remains the best way of ensuring important reactive power reserves are available when required during system emergencies. Reference [17] gives further details on benefits and difficulties of testing generators at reactive power limits.

## **2. System Backup Relays**

System backup relays are generally of three types: phase distance, phase overcurrent, and ground overcurrent. Of these, the ground overcurrent is not affected by excitation levels, so it will not be addressed here. The phase

distance and phase overcurrent relays, however, can be affected by excitation.

In the case of the phase distance relay, depending upon its reach, the combination of low system voltage (due to a collapse) and high load (due to high Var output in response to the collapsing voltage) could be interpreted as a low magnitude three phase fault resulting in an undesirable trip. This is a problem especially if the generator is connected to a stiff system because of the generator's relative inability to control the system voltage regardless of its excitation level.

In the case of the phase overcurrent relays, they are typically set with a pickup below rated load, relying on healthy voltage as a restraint. With the same scenario as in the case above, if the voltage falls below the set-point, the relay could operate on load, again causing an undesirable trip. As with the distance relay, this is more likely to occur when the generator is connected to a stiff system.

It should be noted that undesirable trips could occur under low excitation conditions, as well, because low excitation translates to low terminal voltage, especially when the generator is connected to a weak system. However, the combination of low voltage due to underexcitation, and heavy load is unlikely, so this is seldom a problem.

The probability of undesirable trips of backup protection systems is reduced by detailed application studies when applying such protection and when calculating settings. System simulations for multiple or low probability contingencies may be required to ensure the backup devices are secure under such conditions. If time delays of backup relays are short, dynamic system simulations may be required as well as static simulations.

If reliable backup transmission protection exists at the switching substation, backup phase distance relays may not be needed. Consideration could be given to either removing such relays, or reducing their reach such that

undesirable trippings under low voltage conditions are highly unlikely.

## IV. Switched Capacitance

Switched capacitance is a method of providing reactive power support to maintain voltages within tolerable limits. It is applied in different time frames. Switching must be automatic to be effective in the transient time frames described in Figure II-4 but may be manual or automatic for slower collapses. An important factor in the application of switched capacitors is that the voltage does not rise above tolerable limits in the post disturbance state.

### A. Long-term Time Frame.

Manual switching, or conventional voltage control devices are often adequate for switching capacitors in the longer time frame. Capacitors are considered to be static reactive power sources when applied for long term voltage control. Static capacitors may be switched seasonally, weekly, or daily for this type of application, where the switching devices may be circuit breakers or circuit switchers. The design of the capacitor installation must consider the possible speed and frequency of switching, as well as the voltage support requirements. Very frequent switching would put a significant amount of wear on the switching device.

When the time frame of the voltage stability phenomena approaches the transient region, automatic switching is almost always required. Capacitors are often switched by voltage relays with time delays. To achieve the higher switching speed, additional controls may be required to prevent excessive switching and wear on the switching device. The voltage relays used for switching may not be the conventional voltage control relays. They may need higher accuracy, or different techniques, similar to those used for undervoltage load shedding. For instance, the requirement for switching may need the three phase voltages to be inside a certain window, or the requirement may be controlled by the status of other dynamic reactive power sources such as

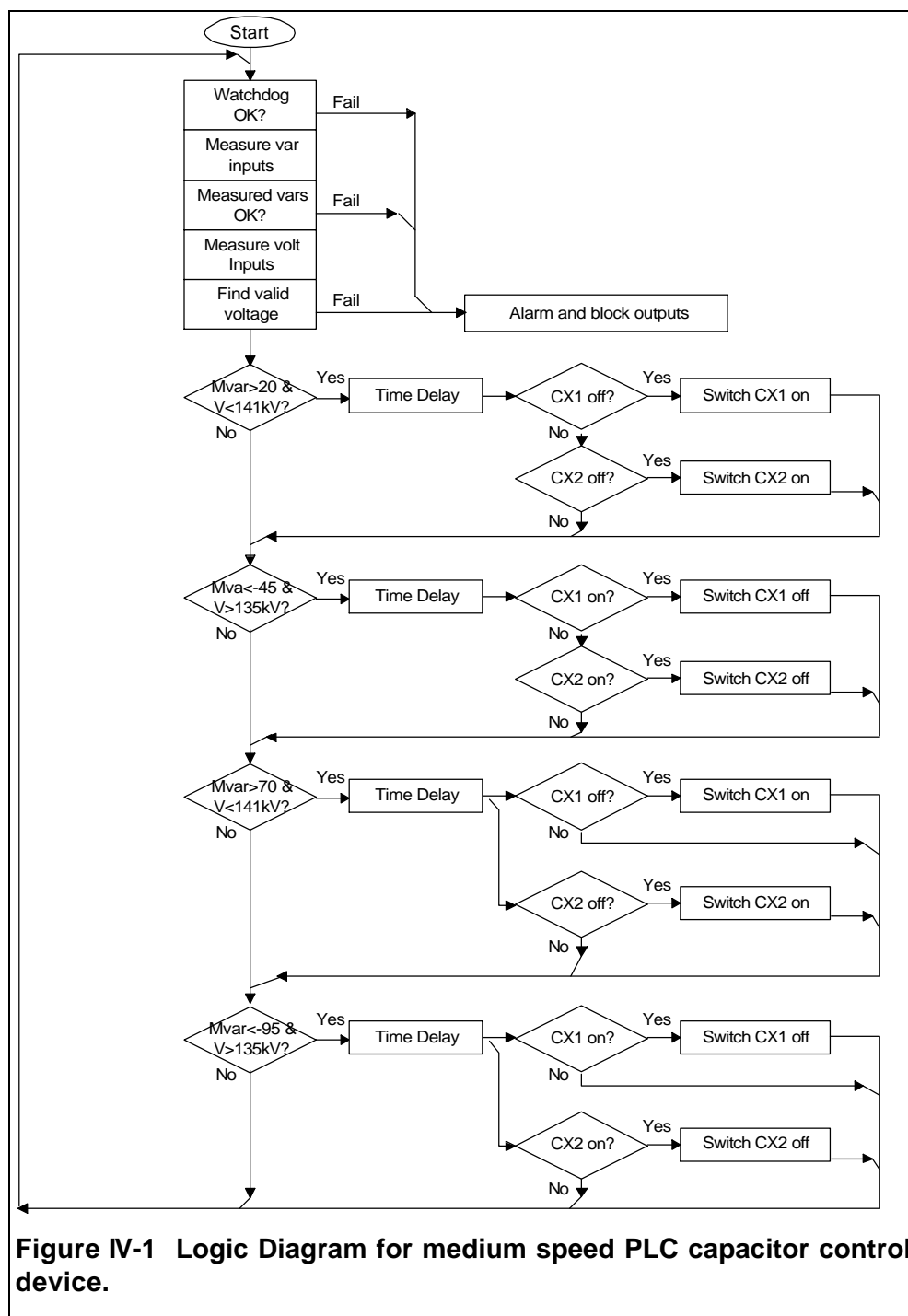
nearby synchronous condensers, or static Var compensators.

BC Hydro uses a PLC to coordinate the measurement of the output of synchronous condensers (rated 2x100 Mvar and 2x50 Mvar) and the switching of 2x50 Mvar capacitor banks. Figure IV-1 shows the simplified logic diagram of the PLC used to control the capacitors.

The capacitor banks are switched if the total output exceeds 60% of the rating of units in service with automatic voltage regulators. The PLC is used to calculate the output from all units. If the output is high, and system voltage is not too high, one capacitor bank will be switched on. If the output is very high, and the voltage is not too high, both capacitors will be switched on. The same device automatically switches the capacitors off if the output of the synchronous condensers goes low, and if the system voltage is not also low. By this means, the utility can control the system such that the synchronous condenser is available for dynamic supply of reactive power by keeping the condenser output low under normal steady state conditions.

This is an example of using relatively slow speed switching of a capacitor to increase reactive reserve earlier than required for an emergency situation. Early switching of static sources means more dynamic power is available for quick support during emergencies.

To minimize wear and tear on the switching equipment, the automatic control is sometimes unidirectional. The reactive equipment is automatically switched on or off, to quickly regulate the voltage excursion, and operator control is used to restore normal conditions when the disturbance is over. This is a major difference between special schemes and normal voltage control devices which switch reactive equipment after very long time delays.



### B. Transient Time Frame

The complexity and sophistication of the control device usually increases as the time frame of switching approaches transient levels. Since voltage control is the objective, voltage sensing devices are the prime tools used. However, additional supervisory devices are required to

prevent unnecessary switching. Some control schemes are described below, as examples of schemes used for capacitor switching in the transient time frame.

### **1. Capacitor Switching in 0.75 Seconds**

Reference [5] describes an undervoltage capacitor switching scheme installed by one utility which operates in conjunction with a load shedding scheme to avoid the possibility of voltage collapse. This scheme is intended to insert a capacitor bank if the voltage drops due to loss of a major system tie transformer.

The bank is connected in 0.75 seconds in an attempt to restore voltages before load has to be shed. The 0.75 second delay is long enough to override voltage depressions due to multi-phase faults on the 161 kV subtransmission system which are normally cleared in less than 0.5 seconds. However the time delay is not long enough to override voltage depressions due to single line to ground faults on the 161 kV system or any type of fault on the 46 kV or 13 kV distribution systems.

Supervision elements are used to block capacitor switching for faults which might be cleared in longer than 0.75 seconds. A zero sequence overvoltage detector is used as a supervision element for 161 kV ground faults, and overcurrent fault detectors are used similarly, to block the switching scheme if the voltage is depressed due to a distribution system multi-phase or single line to ground fault. All measuring and logic functions are accomplished with discrete electromechanical relays in this scheme.

### **2. Capacitor Switching in 0.2 Seconds**

One utility uses fast capacitor switching to maintain voltages on two 230 kV tie lines which are overlaid by a 500 kV line. If the 500 kV line trips out during high load conditions, there is a danger that low voltages on the underlying 230 kV lines will result in loss of angular stability and/or tripping by the line protection systems. Groups of capacitors are located at different substations for each of the two 230 kV lines. One substation has 12x40 Mvar capacitor banks, and the other has 6x30 Mvar banks. The capacitor banks are switched by circuit breakers. Switching must be accomplished very quickly, but not within normal 230 kV multiphase fault clearing times (less than 12 cycles). Switching is not initiated unless all

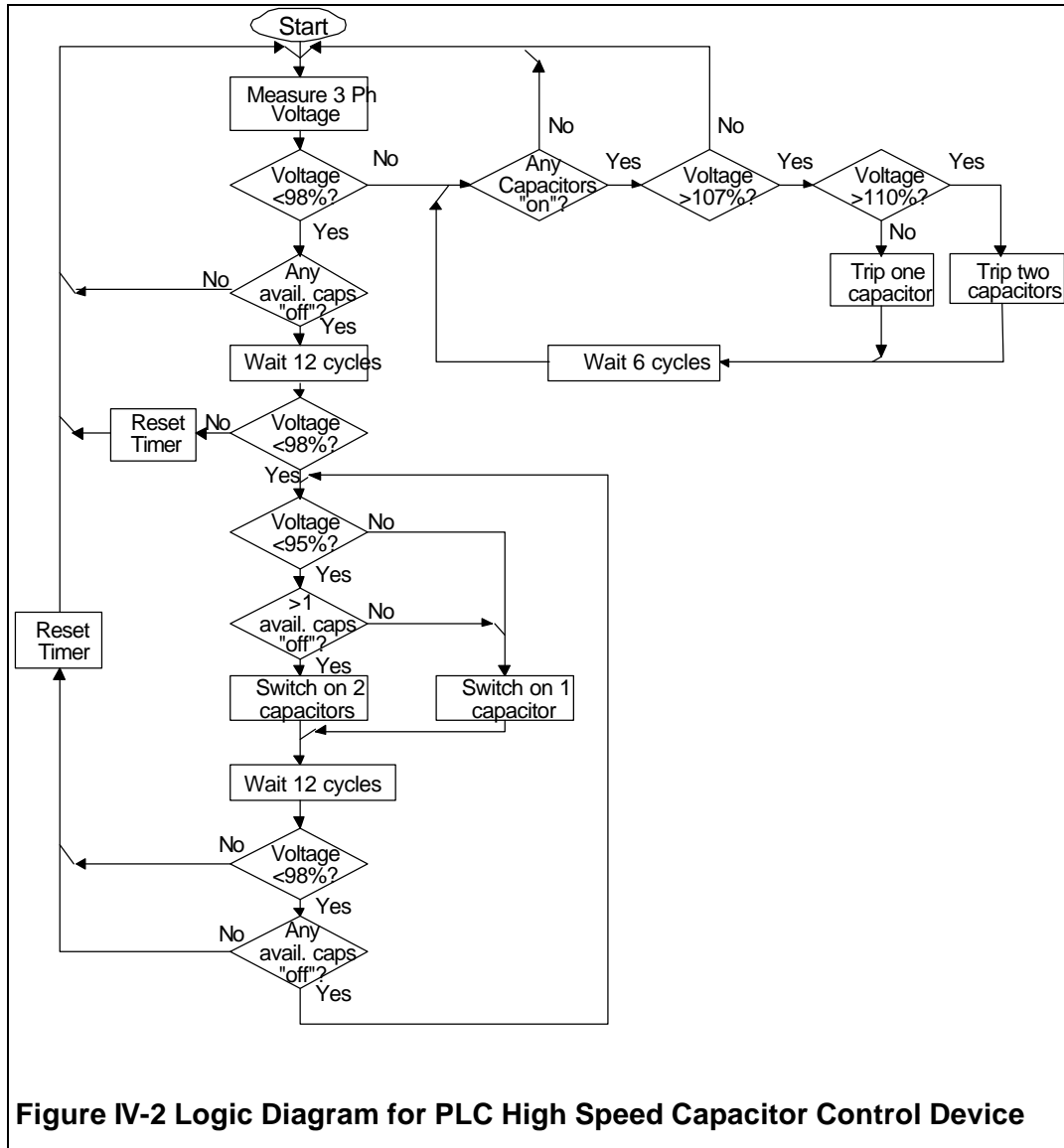
three phase voltages are below the threshold. This reduces the probability of switching for unbalanced faults such as resistive single line to ground faults which might be cleared in longer than 12 cycles. A programmable logic controller (PLC) was selected to perform the measuring and logical functions as shown in Figure IV-2 following.

### **3. Capacitor Switching in 0.15 Seconds**

Mechanically switched capacitors can sometimes be applied for very fast voltage support. In such cases, the control scheme increases in complexity. For instance, in some cases where DC transmission is an important source of power, adequate reactive power is required to support voltages at the receiving terminal after transient voltage depressions due to abnormally cleared faults.

In one case, a very fast capacitor switching scheme is applied to support the voltage at a receiving terminal if the 345 kV (ac) system suffers a fault with associated failure of a single pole of the clearing breaker (with three phase breaker failure not being considered a credible contingency). In this case switching of the capacitor bank is required if the fault is not cleared within 9 cycles. Since the probable situation is a single line to ground fault, the capacitors must be switched for unbalanced voltages. In this case, a directional negative sequence overcurrent relay looking away from the 345 kV system is used to block switching if the unbalanced fault is not on that system. Switching is also initiated for three phase faults anywhere on the system (if clearing is not achieved within 14 cycles).





The above summarizes some of the stand alone applications of capacitor switching for voltage control in different time frames. The application examples also illustrate the flexibility of PLCs in providing a means for complex control functions. As far as time frame is concerned, it is generally accepted that fast action requires more comprehensive control to coordinate with other power system protection and control. However, time frame is not the only factor as location of voltage sensing is also important. Furthermore, capacitor switching can also be a component part of an overall scheme in which the capacitors are not used as the first resort to mitigate voltage collapse (as per Section V).

## V. Automatic Reclosing

Fast reclosure of high voltage transmission is used as the first attempt to restore lost transmission as quickly as possible to minimize exposure to excessive and unacceptable voltage declines and to enhance the stability of the system. Ontario Hydro has implemented a scheme using faster than normal automatic reclosure to prevent voltage collapse in the event of a transmission line outage coincident with outages on other parts of the transmission system. The reclosure attempt must occur within 1.5 seconds after the initial loss of the

transmission line. This time frame is dictated by the effectiveness of subsequent load shedding should the reclosure not be successful. A reclosure time of 1.175 seconds can be achieved with the slowest breakers in the region (closing time 0.225 s). The total reclosure time includes 0.5 s dead time before reclosing the energizing breaker (lead terminal) and 0.1 s delay for closing the follow terminal on restoration of potential from the lead terminal.

If reclosure is unsuccessful, and the load is high, load shedding is required to ensure an acceptable voltage profile. Load shedding must be initiated as soon as possible after unsuccessful reclose attempt if the voltage is lower than 85% of normal levels. A total of 504 MW distributed at nine different stations is available for shedding. Each block of load can be armed by operator action and will be tripped when the local station voltage drops below a preset value for a preset time period. The scheme is based on monitoring the transmission voltage with undervoltage relays on either side of the main or backup potential sources (automatic transfer for loss of the main source). The undervoltage relays are duplicated, and both relays, set to 85% of the normal operating voltage, must operate to shed load. The load is shed if the undervoltage condition persists for more than 1.5 seconds. Load shedding is blocked if both the main and alternate sources are lost (as detected by another undervoltage relay).

A total of 36 capacitor banks (both transmission and distribution banks) in 17 transformer stations in the region are equipped with automatic switching features that are voltage and time dependent. The capacitors maintain the voltage levels at or above the minimum acceptable level of about 90% of nominal. A predetermined sequence of capacitor switching can occur up to 8 seconds after the initial loss of transmission. The effect of capacitor switching following load shedding is that of fine tuning the voltage levels to within the normal band.

## VI. Load Shedding

Load shedding is an option that is becoming more widely used as a final means of avoiding system wide voltage collapse. This option is only considered when all other effective means of avoiding collapse are exhausted. This option may be the only effective option for various contingencies especially if the collapse is in the transient time frame, and if load characteristics result in no effective load relief by transformer load tap changer control. Load shedding results in high costs to electricity suppliers and consumers, therefore, power systems should be designed to require such actions only under very rare circumstances. Load may be shed either manually or automatically depending on the rate of voltage drop.

### A. *Manual Load Shedding*

If the time frame of collapse is long-term, manual load shedding can be implemented to stabilize the voltage. This mode of operation, normally applied under inadequate generation conditions or insufficient Var reserve, should have preplanned guidelines and procedures for the system dispatchers to implement load shedding manually. System studies can provide load sensitivity analyses from which the critical voltage can be determined to start load shedding. Another option to assist system operators for fast action is to preprogram blocks of loads on the dispatcher control console of the SCADA system. Dispatchers can select a particular block of load in a specific area requiring load shedding to control the voltage drop. The blocks of load can also be divided into several subgroups depending on sensitivity of the load, so that execution of the manual load shedding can be carried out in steps or in rolling sequence.

A major disadvantage of relying on manual load shedding is that it places a severe burden on system operators to recognize an approaching voltage stability problem and to act quickly enough to avoid a major collapse. Even with the most comprehensive preplanned guidelines, there is a danger that the particular condition that arises may not fall within the guidelines clearly

enough for prompt action. However, when short term operational planning studies (time frame less than a week) show the possibility of collapse due to expected load and actual contingencies, manual shedding can be applied with good results.

### ***B. Load Shedding as Part of Energy Management Systems (EMS)***

Some utilities have installed remote controlled devices to control the residential air conditioners, water heaters, and other loads as a part of energy conservation effort to reduce system peak demand. During the system peak load condition, a signal will be broadcasted to selected areas to cycle the interruptible loads off for 15-minute intervals. This short interruption will not drastically change the room or water temperature to cause significant discomfort or inconvenience to customers.

This program is normally initiated by system dispatchers or by EMS based on the need of the system. This same program can be used for load shedding either manually by dispatcher control or automatically from EMS if proper logic can be programmed to detect a voltage instability.

To be effective, load shedding from this program requires participation of large groups of customers. Such participation is unlikely to materialize unless there is some sort of financial incentive (such as reduced rates) for participation. This type of action is most likely to be considered when utilities can defer large amounts of capital expenditure to reinforce transmission if the program is implemented. In order to get a reasonable return on the loss of revenue from financial incentives, operation of this type of load shedding scheme would be expected much more often than the alternative of disconnecting large blocks of load under extreme emergency conditions.

### ***C. Automatic Load Shedding***

When the voltage instability is caused by sudden loss of critical transmission equipment or Var generating equipment, the lead-time prior to a voltage collapse will be very short. Therefore,

manual load shedding would be too slow to prevent a voltage collapse. Automatic load shedding must be used to quickly arrest a fast voltage drop and allow the voltage to recover to an acceptable level before voltage collapse can occur.

Undervoltage detectors are often used to initiate automatic load shedding. For low voltage events which do not lead to collapse (such as during a normally cleared system fault), these detectors must not operate in order to prevent nuisance tripping of customer load. Security of the undervoltage detectors can be increased by applying multiple phase detection, proper time coordination between fault clearing and time delay for load shedding, and use of fault detection relays to inhibit load shedding. Reliability of load shedding to prevent voltage collapse can be enhanced by use of other indicators than voltage magnitude such as voltage and power sensitivity factors or other forms of voltage stability indices.

Developing appropriate settings for the undervoltage detectors and time delays are challenging problems. It might require intensive network analysis to find the desired values to provide optimum coordination between load shedding and voltage collapse. Generally, the settings are in the range of 85 to 95 percent of the operating voltages, with time delays ranging from tens of cycles to minutes [1,5,20]. The sensitivity of the load to the voltage level has a great impact on the settings.

For example, air-conditioning load is sensitive to low voltage and can aggravate the system voltage once the voltage drops below a level causing the air conditioners to stall [21]. The aggregated locked rotor currents from stalled air-conditioners, which are almost entirely inductive, could drag the system voltage down if they remain connected to the system. Therefore, the time delay for this type of load shedding may need to be much shorter than others.

On the other hand, if the system is capable of operating in the low voltage condition for long enough, stalled motor load will disconnect itself by its overload protection. Such disconnection was

observed in the Philadelphia Electric Company low voltage incident [10]. The concern was expressed in analysis of that incident that if automatic load shedding had been applied, too much load might have been disconnected, and overvoltages could have resulted.

Automatic load shedding to arrest frequency declines leading to possible blackout is widely accepted and required in many interconnected systems. This type of protection system has proven to be very reliable in not shedding load unnecessarily, and in shedding load when required. Its success is due in part to the close tolerances at which system frequency is normally maintained, and the reliability of deviation outside those tolerances as an indicator of serious generation/load mismatch.

The comparison of settings of relays for underfrequency load shedding with those of relays for undervoltage load shedding is interesting. In order for each member company of a coordinated council to shed the appropriate load, given the same frequency conditions, the settings for the underfrequency relays and their associated timers are generally programmed to trip essentially at the same time. Staged shedding of load is achieved by programming the settings of various relays into different steps of frequencies. However, undervoltage detectors for automatic load shedding may be set at voltage levels close to each other, but spread into steps with different time delays (considerably longer than underfrequency relay trip time). Underfrequency relays are often inhibited during undervoltage conditions to ensure response only to system wide frequency excursions.

Frequency decline due to generation/load mismatch is uniform over a wide area. Underfrequency detectors with similar or identical settings can be applied throughout a system. Voltage magnitude during a voltage instability incident is much more variable in the area under consideration. Undervoltage detectors usually have to be installed in specific areas and locations within a system, depending on system studies to identify the areas with a high probability of voltage collapse. Since undervoltage

detectors are set very close to normal operating voltages, it is sometimes necessary to ensure undervoltage relays sense voltages at very stiff busses. Stiff busses will be better regulated and subject to less disturbance (due to local transient conditions such as faults), than weaker busses.

Use of multiple sensing relays can greatly increase reliability of underfrequency and undervoltage load shedding schemes. In some cases, system studies may show that small frequency changes are a necessary condition for disturbances leading to voltage collapse. In such cases, supervision of load shedding by underfrequency detectors can enhance security of the load shedding scheme. For example, Florida Power and Light supervise a load shedding scheme by underfrequency relays set at 59.9 Hz. These relays trigger a latched relay that stays latched for up to a minute after the frequency excursion. Load shedding is allowed if the latched relay is operated at the same time that the reactive power deficiency decision is transmitted to the load supply point [4].

Some relaying considerations associated with load shedding schemes:

- Undervoltage detectors operate very close to normal operating voltages. Caution is required in setting and application to ensure reliability. Relays must be very accurate, and must be connected to accurate voltage transformers. The relay dropout ratio and dropout time are important factors. If the voltage is depressed and restored due to a transient event, the relays must reset before load shedding is initiated. To minimize the response of relays to voltage depressions due to unbalanced faults, three phase measurement (all three phases must operate) or positive sequence voltage measurement may be employed. To avoid load shedding for loss of potential supply, a window measuring principle may be employed. If the voltage is depressed to a very low level, (such as might occur for loss of potential supply), no amount of load shedding is going to restore voltage to near normal, therefore

the voltage detector may be set to ignore such voltages.

- Steady state phase voltage unbalance due to heavy loading on untransposed lines is also a factor in voltage measurement. Since undervoltage relay settings are very close to normal operating levels, phase voltage unbalance of only a few percent can be significant. Measurement of all three phase voltages or use of positive sequence voltage are techniques used to minimize the effects of steady state phase voltage unbalance.
- Interaction between manual and automatic load shedding schemes could be a problem. It is preferable that there be no interaction between the two schemes. Such independence can be assured by setting time delays of automatic schemes so short that manual actions might not reasonably be expected to overlap. Figure II-4 shows system operator intervention may be expected after 1 minute; so automatic schemes should have completed their action by this time.
- A combination of manual and automatic load shedding is achieved by manually arming automatic schemes when off-line studies or on line indicators show that the possibility of voltage collapse is increasing. Manual control of automatic load shedding schemes is usually achieved by use of SCADA systems. The advantage of manual arming/disarming is that the security of the scheme is increased by blocking it during normal conditions. The disadvantage is that dependability is decreased under fast collapse scenarios by having the need for operator action before the scheme can function.
- Proper selection of blocks of load and duration of shedding for the manual load shedding schemes is important. If manual load shedding is applied to remedy inadequate generation conditions, it should have somewhat different objectives under near voltage collapse conditions. System simulations can produce sensitivity analyses from which the critical blocks of load may be determined.
- Unexpected loss of load (such as tripping of motor starters) in addition to intentional disconnection of load, may result in excessive loss of load. This excessive loss of load, in addition to mitigation measures such as switching on of shunt capacitors, may result in unacceptably high voltages during loss of voltage stability incidents.
- Automatic load restoration may be considered as a means of minimizing excessively high voltages after load shedding. Load should be restored in stages, to prevent subsequent secondary collapses. Automatic load shedding and restoration was helpful in stabilizing voltages in an incident in the Arizona Public Service and Salt River Project (SRP) areas on 29 July, 1995. In this incident, an unusually slowly cleared fault led to air conditioner motor load stalling. A severe and sustained region wide voltage drop was arrested in part by undervoltage initiated load shedding of 1400 MW of SRP load. When voltages started to rise after load shedding, much of the load was automatically restored within 20 seconds. Automatic load restoration schemes must be carefully applied to avoid causing widely fluctuating voltages during voltage instability.
- Future implementation of automatic load shedding schemes may involve more detailed results of network analysis in line with recent understanding of the voltage collapse phenomenon. It may be coupled with faster monitoring systems, and setting points may be calculated on sensitivity analysis of reactive powers and voltages rather than isolated measurements of voltage, or frequency. The choice of loads to be shed in such schemes may be dictated by the nature of active/reactive power imbalance in the system, and should not interact with existing schemes or priority loads.

## VII. Distribution Voltage Control

### A. General

Electric utilities utilize load tapchangers (LTC) to maintain customer voltage levels as the system conditions change. Typically, as load increases, the LTC will act to raise the tap position in order to maintain the voltage level. The LTC control relay will be set to operate in one of two modes - bus voltage regulation or load center voltage regulation using the line drop compensator.

Load Center voltage regulation requires a line drop compensator to regulate the voltage at the load center. Transformers at distribution substations are more likely to use load center voltage regulation than those at transmission substations. Therefore, it is important to know the mode of LTC control operation when modeling the effect of the tapchanging transformer operation during voltage collapse.

During a period of voltage collapse, the LTC control relays will detect a low voltage and begin timing to raise the tap position of the transformer. When the voltage collapse occurs slowly, the controls will time out and begin to raise the transformer tap position. Assuming no change in the load on the transformer during this period, the LTC can often be considered a constant power load (i.e.,  $\alpha$  and  $\beta$  are near zero) as long as the tapchanger can maintain a constant load voltage. Since the primary voltage level drops, the current flow in the transmission system is increased to maintain the load power. This increasing current flow will further reduce the transmission system voltage, making the voltage collapse more severe.

In some cases, tap changers can also have a beneficial effect. Consider for instance, a case where a transformer is supplying predominantly motor load with power factor correction capacitors. The LTC keeps the supply voltage high and hence does not affect the real power consumption (which is relatively independent of voltage), and also maximizes the reactive support from the power factor correction capacitors. Due

to this regulating effect, the LTC is an important part of the overall voltage collapse scenario.

For the more frequent case, where the real power loads have some voltage dependency, the LTC can be utilized to reduce the severity of the voltage collapse if appropriate control operation can be obtained. Blocking operation of the LTC has been widely offered as a method to reduce the negative effect on the system. Load voltage reduction can be used to reduce the loading on the system. This is similar to the peak shaving systems widely used at many utilities. Therefore the load tapchanger may be both a cause and a partial solution to the problem of voltage collapse.

### B. LTC Blocking Schemes

The simplest method to eliminate the LTC as a contributor to voltage collapse is to block the control's automatic raise operation during any period where voltage collapse appears to be a concern. The decision to temporarily block the tapchanger can be made using locally derived information or can be made at a central location and the supervisory system can then send a blocking signal to the unit. This action may result in a period of low voltage on the affected loads. The effect of the reduced supply voltages on power quality to customers in the whole service area must be weighed against the possible alternative of complete disconnection of some customers in a smaller area. Tap changer blocking will be more effective for voltage decays slower than the transient time frame. It will also be more effective on loads that have a relatively high voltage dependency (i.e.,  $\alpha$  approaches 2 and  $\beta$  is considerably higher). In cases where the steady state value of  $\beta$  is high (such as the value of 4 as seen in Figure II-5), the reduction of reactive power demand due to reduced distribution voltage will be very significant in helping keep transmission voltages up.

Local blocking schemes are implemented using voltage relays and timers to sense the voltage level on the high voltage bus at the substation. The setpoint voltage is usually chosen to be a level that is less than that which occurs during maximum acceptable overload conditions.

Blocking is initiated if the abnormal undervoltage condition exists longer than a predetermined time. The time period may vary from 1 to several seconds. The LTC is unblocked when the voltage has recovered to an acceptable level for a predetermined period of time, typically 5 seconds. Since the blocking action will be removed if the voltage recovers, usually a single phase-phase voltage measurement is adequate for this scheme.

A coordinated blocking scheme can be utilized to block operation of LTC's in an area where voltage instability is imminent. The coordinated scheme can be accomplished with undervoltage schemes acting independently (as described above) in a coordinated fashion at various stations within a region, or it can be a centralized scheme that recognizes a pattern of low voltages at key locations. In a centralized scheme, the LTC blocking can be implemented in substations throughout the affected region, even if the voltage at all locations is not yet below a specific threshold. The key to operation of a centralized system is the reliability of the communications system. The data needed for decision making must be collected at the central location for analysis. Control decisions must then be sent to each affected transformer location.

The effectiveness of an LTC blocking scheme at the transmission level will largely depend on whether distribution transformers are LTC-type. If the distribution transformers are LTC-type, additional measures are required to prevent their action from negating the effect of the LTC blocking scheme at the transmission level.

The blocking schemes described above require an accurate measurement of the high voltage level at each substation. When high side potential devices exist at the substation, this voltage measurement can be made directly. In substations that do not have potential devices on the high voltage, an estimation of the high voltage level can be made from a voltage measurement made on the low voltage side of the LTC transformer. In order for this estimate to be accurate, several data items must be considered in the estimation. The tap position of the

transformer must be accurately estimated so that the voltage calculation will be accurate. This information can be derived via several methods and must be then utilized by the measuring relay. The transformer load current, series reactance, and series resistance are also required to estimate the voltage drop due to load current. If load current is near unity power factor, the series resistance of the transformer will be the most important factor in its impedance. If there is significant reactive power flow through the transformer, the voltage drop across the series reactance will also be important. By combining the effects of the variable tap position of the transformer and the voltage drop caused by load current, a reasonably accurate estimation of the high voltage level can be made.

### **C. Distribution Voltage Reduction**

Many utilities have implemented systems to reduce distribution voltages during peak load periods. The reduction in voltage is used to reduce the system peak demand. In a similar fashion the voltage reduction concept can be used during periods where voltage stability margins are insufficient.

An example of voltage reductions for peak shaving follows:

*Voltage reductions represent an operating tool that may be included in load management programs. The Pennsylvania-New Jersey-Maryland Interconnection (PJM) utilizes 3% and 5% voltage reductions to aid in curtailing peak load when required to provide sufficient reserves to maintain tie flow schedules and preserve limited energy sources. Voltage reductions are initiated for both capacity shortages and when reactive limits are reached or exceeded. Experience has indicated that implementing a 5% voltage reduction on the PJM system will result in an initial load reduction of approximately 2%.*

*The mechanics for implementing voltage reductions varies among the PJM member companies since voltage control methods and*

*facilities differ. In general, if load tap changing facilities are available at distribution substations, tap changes or voltage schedule changes are initiated remotely by supervisory or radio control. If remote control facilities do not exist, such action must be taken manually at the station. Some companies utilize load tap changing facilities at the subtransmission level rather than at the distribution level. In such cases, the subtransmission voltage is reduced in order to lower the underlying distribution voltages. In cases where automatic load tap changing is employed, control systems are used in which the tap changer controller is fooled into thinking that the controlled voltage is 3% or 5% high. The controller action subsequently automatically provides the action to implement the desired voltage reduction.*

*Voltage reductions during reactive emergencies can provide the additional benefit of increasing the connected reactive support by forcing on capacitors which may have not been switched into service by their associated voltage controllers. Localized problems may occur during voltage reductions due to the existence of voltage sensitive customers in an area. In such cases, member companies are given the flexibility to deviate from the voltage reduction directive in the specific problem areas.*

Voltage reduction schemes involve changing the setpoint of the systems distribution transformer LTC controls so that a lower distribution voltage is achieved. Several types of systems have been developed to implement voltage reduction. Voltage fooler circuits are used to increase the sensing voltage input to the LTC control relays. These circuits typically consist of a step-up transformer, with one or more taps, in series with the potential input to the control. Using SCADA contacts the LTC control is fed a voltage that is higher than the actual voltage, causing the control to act to lower the voltage. In some cases the controls preset time delay is bypassed,

eliminating the delay typically present in the automatic control. In transformers, with static or digital controls, voltage reduction inputs are available that provide equivalent operation without the necessity of adding the fooler circuit. In either case, the voltage reduction schemes typically have one to three discrete steps available to the user. Typically steps of 2.5%, 5%, and 7.5% of voltage reduction can be selected by the system operator or SCADA system.

During a period of potential voltage instability the voltage reduction scheme could be utilized to reduce the system voltage to its minimum level so as to reduce the load as much as possible. This step could be instituted prior to any load shedding and could reduce the need for load shedding and the corresponding load disruption. The voltage reduction scheme could be implemented using a distributed or by a centralized measuring system similar to the systems described above.

#### **D. Comparison of Voltage Reduction and Blocking Schemes**

These schemes are similar to each other in trying to minimize the chance of complete disconnection of some customers by providing slightly reduced voltage to most customers. Their effectiveness are both similarly dependent of load characteristics and the time frame of voltage decay.

The load characteristics are important in determining the amount of load relief that may be expected for a given voltage depression. For loads that are predominantly motor loads, the real power loss is minimal for a small voltage depression. Thus load mix (ratio of residential, commercial and industrial loads) is important as well as seasonal characteristics (air conditioning loads for summer peaks). The time frame is important because LTCs are effectively blocked in the transient time frame. As shown in Figure II-4, LTCs do not start to move until after the transient time frame.

The voltage reduction scheme has an advantage over the blocking scheme in that the quality of power supplied to customers remains defined by



the new (reduced) set point. It has a potential disadvantage however, of providing less load relief than the blocking scheme which allows distribution supply voltages to drift down to whatever levels the transmission voltage goes to.

A major point of concern in application of the blocking scheme using local voltage detectors is that the LTC may have already moved to near its full boost position by the time the primary voltage has reduced to a level below the normal maximum. Thus blocking the LTC may be too late. Use of a centralized decision which could be taken at an earlier time (since more information may be available to determine the possible onset of collapse), may allow blocking the LTC when it is in a near normal position. This concern is not as important in a voltage reduction scheme which retains control of the LTC.

With both schemes, the characteristics of the distribution system is important. To minimize unacceptable power quality to some customers, the voltage profile along the distribution feeder should be fairly flat. If the profile is too steep, it will not be possible to reduce voltage levels at customers near the substation without reducing voltage levels at distant customers to unacceptable levels.

## **VIII. Conclusion**

### **A. *The fundamental principles of mitigation actions***

**Anticipate the problem** by using load flow and stability studies to identify system conditions that may lead to voltage instability. Conditions that lead to voltage collapse may be caused or aggravated by heavy power transfer between regions; so coordination among the affected regions is essential to develop the appropriate mitigative action. Results of these studies can be used to develop special operating procedures to minimize the probability of collapse. Where studies show that operating procedures alone are not sufficient to ensure voltage stability, special control and protection schemes can be applied to mitigate the conditions leading to collapse.

**Use appropriate diagnostic techniques** to provide early warning of the onset of voltage stability problems. Since voltage collapse is a wide area problem, these techniques often need communications assistance. The communications are not necessarily high speed, but must be reliable. The techniques involve measurement of relevant factors such as voltage magnitude, status and output of sources of reactive power, rate of change of reactive power generation with respect to load, and magnitudes of real and reactive power flows.

**Provide temporary reactive support** until operator action can stabilize system. This may require taking advantage of temporary overload capabilities of generators and synchronous condensers in the affected area. To ensure full capability of all sources are available, they should be operated from time to time at maximum and minimum reactive outputs to ensure all protective devices coordinate properly with control devices.

**Provide permanent reactive support.** Since it is deficiency of reactive power sources that causes voltage to drop, provision of these sources are an effective means of maintaining voltages. Switched capacitors are a popular means of providing such support, but care must be taken to avoid depending entirely on fixed support such as is provided by capacitors. Fixed sources do not provide the control of system voltage which is critical in near collapse situations.

**Provide an appropriate mix of static and dynamic sources of reactive support.** Although dynamic sources of reactive power are much more expensive than fixed sources, they do have the advantage of being able to control voltages. Some relatively economical means of providing dynamic support include use of LDC so that generators regulate voltages some distance from their terminals. Conversion of uneconomic generators to synchronous condensers, and fast switching of capacitors are sometimes options for increasing the availability of sources of dynamic reactive support. Where possible, dynamic sources of reactive power may be

operated as near to mid output as possible to maximize dynamic reactive reserve. Manual or automatic switching of static sources (or sinks) of reactive power is a better means of keeping dynamic sources near the middle of their operating range than adjusting their reference voltage.

**Provide temporary load relief by blocking tap changers or reducing distribution supply voltage.** The amount of load relief provided by these means is determined entirely by the static and dynamic characteristics of the real and reactive components of the load with respect to voltage level. These characteristics vary widely, and may need to be determined by test. The reduction in reactive power demand with voltage is often larger than the reduction in real power demand. It must be ensured that voltage quality is not degraded so much that the alternative of load shedding would not have been preferable to the customer.

**Shed load.** This alternative is the ultimate short term mitigation action. Since the cause of voltage collapse is an excess of load for the given transmission system, load shedding is a clearly effective action. This action is likely to find increasing application as utilities balance the alternative of power supply reliability with power supply cost.

***B. Choice of action(s) depends to a large extent on dynamics***

The speed of collapse can vary widely from a few seconds to tens of minutes. Since many of the mitigation actions offer temporary benefits, their effectiveness will vary widely with the dynamic characteristics of the collapse. Therefore, there are no actions that are generally preferable for all types of power systems.

Protection and control actions must be coordinated with each other. As it becomes more difficult to provide new transmission and generation, utilities rely more on complex, and diverse protection and control systems. To ensure coordination is achieved, two items become important - communications and test.

Communications are required to ensure coordination between different geographic locations. Test of coordination by regular exercising of control actions while the power system is not stressed is the best way to ensure they will operate properly and coordinate with each other and with protection systems under stressed conditions.

System dynamics in the voltage collapse time frames depend on three factors, temporary overload capability of dynamic sources of reactive power, timing of control devices such as transformer load tap changers, and dynamic response of loads to voltage changes. Of these factors, it is usually the load characteristics that are most difficult to determine. Even if load characteristics are determined by test, mitigation actions based on these characteristics should be initiated in the region where the characteristics are valid. For instance, if tests have determined the characteristics within the range 0.95 to 1.05 p.u., the same characteristics cannot be expected if the voltage drops to 0.85 p.u. At voltages less than 0.9 p.u., system response to mitigation actions is very uncertain.

Operator training and response is very important. Operators must be able to recognize voltage instability conditions and must be able to act promptly and effectively to arrest collapse. The time frame of collapse is often longer than operator response time. All automatic actions which are intended to provide temporary relief must be accompanied by clear indication of their action; so that operators can recognize the conditions. Further, operator training must include clear direction as to actions they are required to take when voltage collapse is imminent.

The study of voltage stability phenomena and definition of alternatives is the system planner's responsibility. Protection engineers can help in ensuring reliability of mitigation actions by proper design, and by coordination with other protection and control actions affecting system stability.

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