VOLTAGE COLLAPSE: INDUSTRY PRACTICES

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I. INTRODUCTION

The problem of voltage stability is not new to power system practising engineers. The phenomenon was well recognized in radial distribution systems and was explained in its basic form in a number of text books [1,2]. However, it is only in recent years that the problem has been experienced at bulk transmission system levels in well-established and extensively networked systems. Most of the early developments of the major HV and EHV transmission networks and interties faced the classical machine angle stability limitation. Innovations in analytical techniques and stabilizing measures made it possible to maximize the power transfer capabilities of the transmission systems. The result was increased power transfers over long distances of transmission. As a consequence, many utilities have been experiencing voltage related problems, even when angle stability is not a limiting factor. Some, however, recognized the problem after being exposed to catastrophic system disturbances ranging from post contingency operation under low voltage profile to total voltage collapse.

Major outages, attributed to this problem, have been experienced in the United States, France, Sweden, Belgium, and Japan. There have also been cases of localized voltage collapse (e.g. B.C. Hydro - Canada). Voltage stability has thus emerged as a governing factor in both planning and operation of a number of utilities. Consequently, major challenges in establishing sound analytical procedures and quantitative measures of

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proximity to voltage instability have been facing the industry for the last few years.

The significance of this phenomenon was emphasized by two surveys in the last decade. One of these surveys, conducted by Electricite de France (EDF) identified world wide 20 major disturbances leading to voltage collapse. Analysis of the characteristics of the affected systems and the disturbances revealed the following [3]:

- Before the disturbance: The systems were weakened by outages (lines or plants) or temporary operating conditions, due to maintenance, combined with high system loading.

- The disturbance: In more than half the cases, the loss of only one element was sufficient to initiate the disturbance. In the remaining cases, successive faults lead to loss of parts of the network. In several cases, the disturbance was initiated by a bus fault during substation maintenance. In all the cases, there was at least one event categorized as "should never have occurred" (e.g. human error or equipment malfunction).

- After the disturbance: Delays in system restoration were usually due to difficulties in matching extreme boundary conditions of various parts of the affected networks.

The second survey was conducted by the IEEE Working Group on Voltage Stability in 1988 to determine the extent of the problem in the utility industry [4]. The following is a summary of the responses received from 116 key operating personnel:

- About 40% of the respondents indicated that their systems have voltage stability related limitations. The instability could be initiated by a wide variety of contingencies such as loss of a transmission line, reactive support or generation. These contingencies could be within their own systems or in neighbouring systems. Also, some of the contingencies were further aggravated by limitation of voltage control.

- Only 65% of those who have voltage stability limited systems have related criteria, but almost half of them base their criteria on simple upper and lower operating bus voltage limits.

Thus, the voltage stability phenomenon has emerged as a major problem currently being experienced by the electric utility industry. In this chapter, we have attempted to provide information related to utility experiences and practices with regard to this problem. It is hoped that this chapter would provide researchers and practising engineers working in this area the general background useful in their efforts to deal with the problem.

II. BASIC CONCEPTS AND DEFINITIONS

In its simple form, voltage stability may be explained by considering a simple radial system of a source feeding a load (P,Q) through a transmission line represented by its series impedance and shunt capacitance.

If the sending end voltage is fixed and the active demand is incremented while maintaining the power factor constant, a curve similar to the one shown in Figure 1 would be obtained by plotting the received active power against the receiving end voltage. If sending end voltage and load active power were fixed while varying load reactive power, one of the family of curves of Figure 2 would be obtained by plotting the received reactive power against the receiving end voltage. If the sending end voltage is allowed to change at constant load, the family of curves in Figure 3 would be obtained.

The right edge of the V_r-P curves in Figure 1 and the bottoms of the Q-Vr curves in Figure 2 and the Vs-Vr curves in Figure 3 are the voltage stability limits of the simple radial network and are interrelated. The top part of the V_r-P and the right parts of the Q-Vr and the Vs-Vr curves characterize the stable operating points of the network. The unstable parts of the curves are characterized by excessive reactive power losses in the network for incremental increase in demand which brings the receiving end voltage further down until complete collapse. While it was possible to obtain the unstable parts of these curves analytically because of the simplicity of the example network, they are not as easy to calculate numerically for a complex network. Special numerical techniques have been suggested in the literature for this purpose.

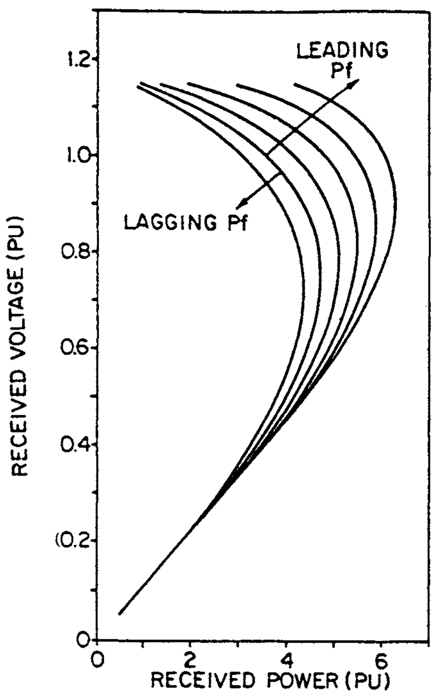


Figure 1: V_r-P Characteristics

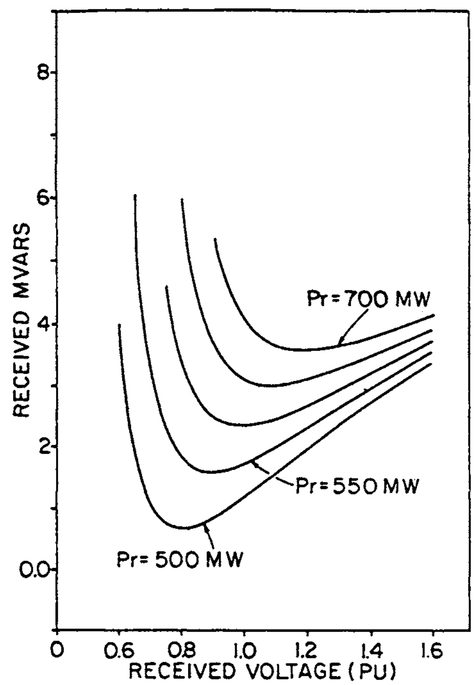


Figure 2: Q-V_r Characteristics

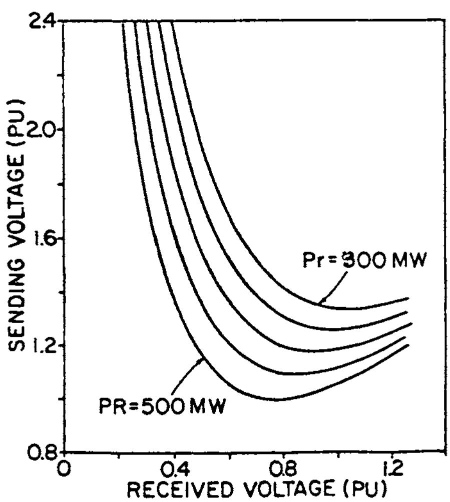


Figure 3: V_s-V_r Characteristics

One can further view the above example as an active dipole feeding a passive load of a certain impedance. The maximum transmitted power is achieved when the load impedance matches the driving point impedance as observed from the source to the load. This maximum power is the voltage stability limit of Figure 1. Any attempt to increase the load demand beyond this limit (by reducing the load impedance) would cause a reduction in voltage and reduction of power.

Based on the foregoing, voltage stability is defined as the ability of a system to maintain voltage such that an increase in load demand is met by an increase in power [4,5]. A load demand here means switching in a load admittance, which may or may not result in an increase in power consumption. As the control and protection devices try to correct the situation (e.g. automatic tap changing, generator excitation limiting, etc.) voltage instability may lead to voltage collapse. The extent of voltage collapse of a given network depends largely on dynamic load characteristics, undervoltage load tripping, and voltage control strategy. For the above reasons we emphasize the difference between voltage instability and voltage collapse.

At this point, it may be useful to explain the dynamic behaviour of some of the relevant elements of a power system [4,6]. Consider a typical mixture of residential, and industrial loads. As the distribution voltage drops, the active and reactive power of the residential load are likely to drop by a factor close to the square of the voltage ratio, thus reduction of the line loadings and reactive losses, while the change in their industrial counterparts would be relatively minor. Moreover, the contribution of shunt capacitors would also be reduced by the square of the voltage ratio which may increase the industrial reactive demand on the system. The changes may nearly balance and tend to stabilize the voltage at a low value.

The action of the voltage regulating devices, primarily the on-load tap changers, would tend to restore the distribution voltage. This would increase the residential load considerably and reduce the reactive demand of the industrial load slightly. The net result is reduction of the primary voltage further which, in turn, reduces the line charging and primary capacitors support to lower the primary voltage further and further unless the tap changers reach their limits. This indicates that under these conditions, it may be advantageous to block the tap changing action as will be seen later.

III. ANALYTICAL TECHNIQUES

Voltage stability problems normally occur in heavily stressed systems. While the disturbance leading to voltage collapse may be initiated by a variety of causes, the underlying problem is due to an inherent weakness in the power system. In addition to the strength of transmission network and power transfer levels, principal factors contributing to voltage collapse are generator reactive power capability limits, load characteristics, characteristics of reactive compensation devices, and the action voltage control devices such as underload transformer tap changers.

Voltage stability is indeed a dynamic phenomenon and can be studied using time domain stability simulations. However, system dynamics influencing voltage stability are usually slow. Therefore, many aspects of the problem can be effectively analyzed using static methods, which examine the viability of the equilibrium point represented by a specified operating condition of the power system. The static analysis techniques allow examination of a wide range of system conditions and, if appropriately used, can provide much insight into the nature of the problem and identify the key contributing factors. Dynamic analyses, on the other hand, are useful in a detailed study of a specific voltage collapse situations, coordination of protection and controls, and testing remedial measures. Dynamic simulations also examine if and how the steady-state equilibrium point will be reached.

In this section, we will discuss the analytical techniques currently used by the utility industry, the limitations of this approach, and some of the improved techniques that have been found to be attractive for practical application.

A 30 bus test system shown in Figure 4 is used to illustrate application of different analytical techniques considered in this section. The total system load for the base case is 6150 MW. In order to examine conditions near the voltage stability limit, the system load and generation are scaled up uniformly throughout the system. At the highest load level for which a feasible power flow solution can be obtained, the total system active power load is 11,347 MW. All generators, except the two at bus numbers 22 and 23 are assumed to have unlimited reactive power output capability.

A. Current Practice

The electric power utility industry at present depends largely on conventional power flow programs to analyze voltage stability problems. Two characteristics, V-P curves and Q-V curves, are normally used to examine system operating conditions and their proximity to voltage instability. These characteristics were discussed with respect to a simple radial system in Section II, and similar relationships apply to large practical systems.

Figure 5 shows the V-P curve for the test system of Figure 4. Voltage at bus 24, which is a critical bus prone to voltage instability, has been plotted as a function of total system active power load. This curve has been produced using a series of power flow solutions for various system load levels. At the 'knee' of the V-P curve, the voltage drops rapidly with

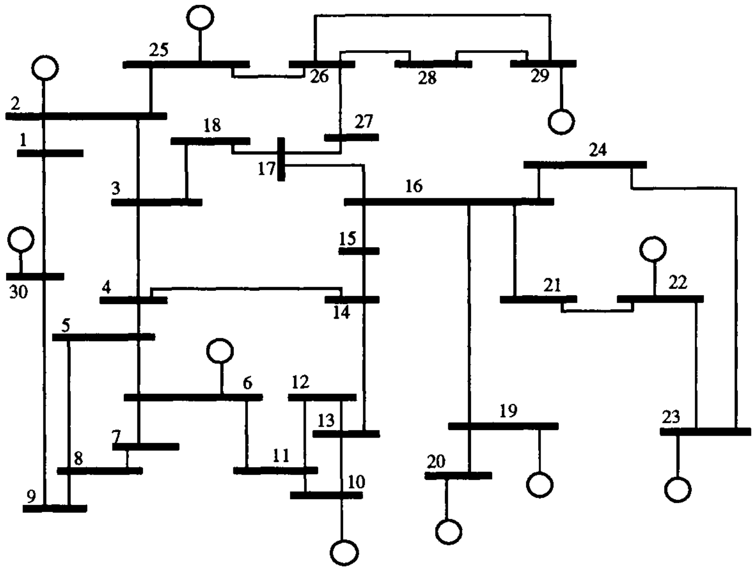


Figure 4: Test System

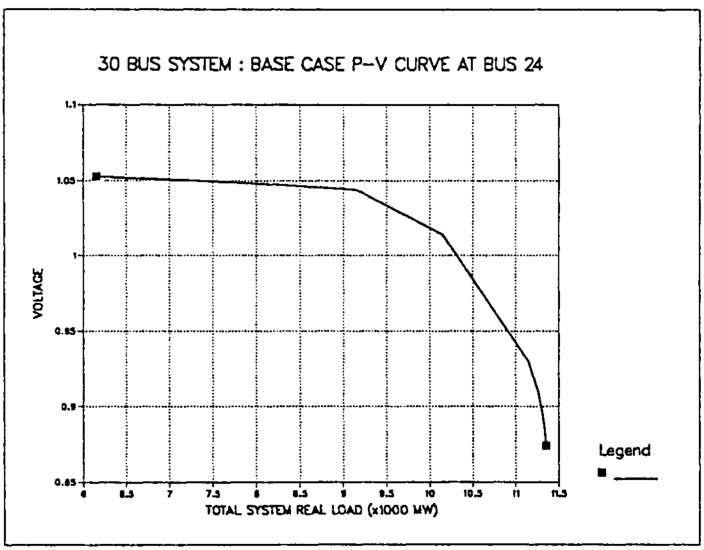


Figure 5: V-P Curve at Bus 24

increase in load power. Power flow solution fails to converge beyond this limit, and this is considered to be indicative of instability. Operation at or close to the stability limit is impractical and a satisfactory operating condition is ensured by allowing sufficient "power margin".

Figure 6 shows the Q-V curves computed at buses 1, 9, 21 and 24 for the base case with a total system load of 6150 MW. Each of these curves has been produced by successive power flow calculations with a variable reactive power source at the selected bus and recording its values required to hold different scheduled bus voltages. The bottom of the Q-V curve, where the derivative dQ/dV is equal to zero, represents the voltage stability limit. For each value of Q above the minimum value, there are two values of V. Since all reactive power control devices are designed to operate satisfactorily when an increase in Q is accompanied by an increase in V, operation on the right side of the Q-V curve is stable and on the left side is unstable. Also, voltage on the left side may be so low that protective devices may be activated. The bottom of the Q-V curve, in addition to identifying stability limit, defines the minimum reactive power requirement for stable operation.

Figure 7 shows the Q-V curves for the four selected buses for the critical case which corresponds to the highest load level (total system load 11,347 MW) for which converged solution could be obtained. It is seen that buses 21 and 24 are on the verge of voltage instability. The bottom of the Q-V curves for buses 1 and 9 could not be established because of power flow convergence problems.

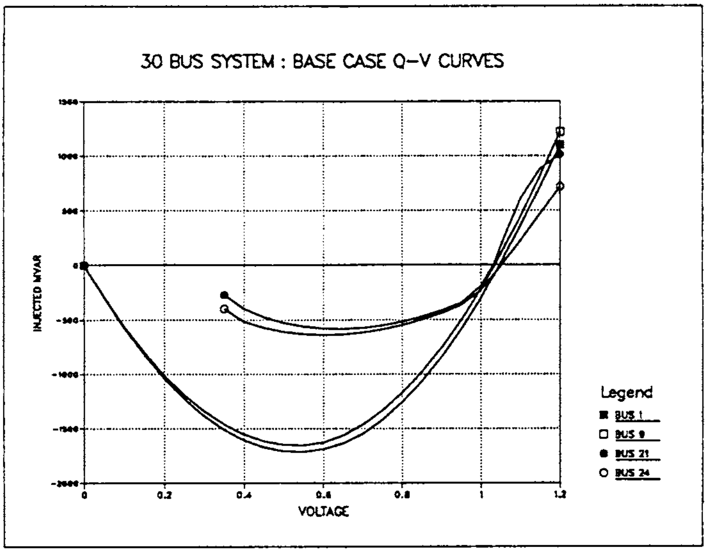


Figure 6

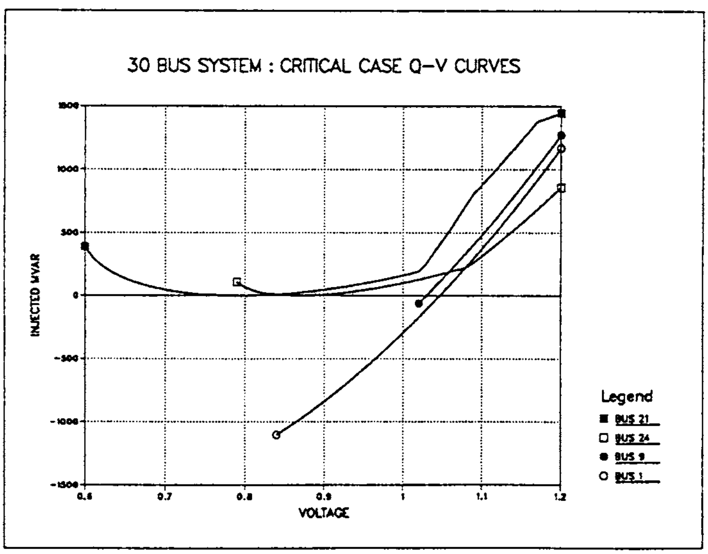


Figure 7

Determination of both V-P and Q-V curves requires execution of a very large number of power flows representing different system and loading conditions. While such procedures can be automated, they are time consuming and do not provide sensitivity information useful in gaining insight into causes of the stability problem. Therefore, as identified in [4], there is a need for analytical tools capable of the following:

- Accurately quantifying voltage stability margins;
- Predicting voltage collapse in complex networks;
- Defining power transfer limits with regard to voltage instability/collapse;
- Identifying voltage-weak points and areas susceptible to voltage instability;
- Determining critical voltage levels and contingencies; and
- Identifying key contributing factors and sensitivities affecting voltage instability/collapse, and providing insight into system characteristics to assist in developing remedial actions.

Further, system modelling used in conventional power flow studies may not be adequate for investigation of voltage stability. The following sections identify the differences in modelling requirements and describe special analytical techniques for voltage stability analysis which have been found to be attractive for practical applications.

B. Modelling Requirements

The following is a brief description of models for power system components which for voltage stability analysis differ from those for conventional power flow analysis [7].

Generators

For power flow analysis, a synchronous generator is modelled as a P,V bus when operating normally and as a P,Q bus when the reactive power output is at its limit.

For voltage stability analysis, it may be necessary to account for the droop characteristic of the AVR, rather than assume zero droop. If load (line drop) compensation is provided, its effect should be represented. Field current and armature current limits should be represented specifically, rather than as a fixed value of maximum reactive power limit.

Loads

Load characteristics could be critical in voltage stability analysis. Unlike in conventional power flow analysis, expanded subtransmission system in voltage-weak area may be necessary. This should include underload tap changer (ULTC) action, reactive power compensation and voltage regulators in the subtransmission system.

Voltage and frequency dependence of loads are important. It may also be necessary to model induction motors specifically.

Static VAR compensators (SVC)

When the SVC is operating within the normal voltage control range, it maintains bus voltage with a slight droop characteristic. When operating at the reactive power limits, the SVC becomes a simple capacitor or reactor; this could have a very significant effect on voltage stability. These characteristics of SVC should be represented appropriately in voltage stability studies.

Power flow programs in current use do not in general provide special SVC models. Therefore, SVCs are represented as simple reactive power sources with maximum and minimum output limits. Such a representation when used for voltage stability studies leads to overly optimistic results.

Automatic generation control (AGC)

For contingencies resulting in a significant mismatch between generation and load, the impacts of primary speed control and supplementary tie-line bias frequency control need to be represented.

C. Special Static Analysis Techniques

A number of special algorithms have been proposed in the literature for voltage stability analysis using the static approach. In this section, we will discuss three of these methods which appear to have certain practical advantages.

V-Q sensitivity

In this method, V-Q sensitivity at each load bus is calculated using the Jacobian matrix associated with the power flow equations.

The linearized steady state system power voltage equations are given by,

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_{P\Theta} & J_{PV} \\ J_{Q\Theta} & J_{QV} \end{bmatrix} \begin{bmatrix} \Delta \Theta \\ \Delta V \end{bmatrix} \tag{1}$$

where,

ΔP = incremental change in bus real power.
ΔQ = incremental change in bus reactive power injection.
$\Delta\Theta$ = incremental change in bus voltage angle.
ΔV = incremental change in bus voltage magnitude.

If the conventional power flow model is used for voltage stability analysis, the Jacobian matrix in (1) is the same as the Jacobian matrix used when the power flow equations are solved using the Newton-Raphson technique. With enhanced device models included, the elements of the Jacobian matrix in (1) are modified appropriately.

In (1), let $\Delta P = 0$, then,

$$\begin{aligned} \Delta Q &= [J_{QV} - J_{Q\Theta} J_{P\Theta}^{-1} J_{PV}] \Delta V \\ &= J_R \Delta V \end{aligned} \tag{2}$$

and,

$$\Delta V = J_R^{-1} \Delta Q \tag{3}$$

where,

$$J_R = [J_{QV} - J_{Q\theta} J_{P\theta}^{-1} J_{PV}] \tag{4}$$

The matrix J_R^{-1} is the reduced V-Q Jacobian. Its i^{th} diagonal element is the V-Q sensitivity at bus i. For computational efficiency, this matrix is not explicitly formed. The V-Q sensitivity is calculated by solving (2).

A positive V-Q sensitivity is indicative of stable operation; the smaller the sensitivity, the more stable the system. As stability decreases, the magnitude of the sensitivity increases, becoming infinity at the stability limit. Conversely, a negative V-Q sensitivity is indicative of unstable operation. A small negative sensitivity represents a very unstable operation.

For the 30 bus test system of Figure 4, Table I shows the ranking of load buses based on V-Q sensitivities for the base case as well as the critical case. It is seen that, for the critical case, buses 21 and 24 are approaching instability. This is consistent with the results based on Q-V curves shown in Figure 7.

It should be noted that, because of the nonlinear nature of the V-Q relationships, the magnitudes of the sensitivities for different system conditions do not provide a direct measure of the relative degree of stability [7].

Table I. Ranking of Buses Based on V-Q Sensitivities

Base Case			Critical Case		
Rank	Bus #	DV/DQ	Rank	Bus #	DV/DQ
1	12	0.02407	1	21	2.90036
2	24	0.02176	2	24	1.86986
3	9	0.01549	3	16	0.15838
4	1	0.01502	4	15	0.10972
5	27	0.01480	5	17	0.08262

An approach using V-Q sensitivity and piecewise linear power flow analysis is used in [8] and [9] for on-line application of voltage instability analysis.

Modal analysis [7]

Voltage stability characteristics of the system can be identified by computing the eigenvalues and eigenvectors of the reduced Jacobian matrix J_R defined by (4).

Let,

$$J_R - \xi\Lambda\eta \qquad (5)$$

where,

ξ = right eigenvector matrix of J_R
η = left eigenvector matrix of J_R
$\wedge$ = diagonal eigenvalue matrix of J_R

and,

$$J_R^{-1} = \xi\Lambda^{-1}\eta \tag{6}$$

From (3) and (6), we have,

$$\Delta V = \xi\Lambda^{-1}\eta\Delta Q \tag{7}$$

or,

$$\Delta V = \sum_i \frac{\xi_i \eta_i}{\lambda_i} \Delta Q \tag{8}$$

Where ξ_i is the i^{th} column right eigenvector and η_i the i^{th} row left eigenvector of J_R.

Each eigenvalue λ_i, and the corresponding right and left eigenvectors ξ_i and η_i, define the i^{th} mode of the system. The i^{th} modal reactive power variation is,

$$\Delta Q_{mi} = K_i \xi_i \tag{9}$$

where,

$$K_i^2 \sum_j \xi_{ji}^2 = 1 \tag{10}$$

with ξ_{ji} the j^{th} element of ξ_i.

The corresponding i^{th} modal voltage variation is,

$$\Delta V_{mi} = \frac{1}{\lambda_i} \Delta Q_{mi} \tag{11}$$

The magnitude of each eigenvalue λ_i determines the weakness of the corresponding modal voltage. The smaller the magnitude of λ_i, the weaker the corresponding modal voltage. If $|\lambda_i| = 0$, the i^{th} modal voltage will collapse. In (8), let $\Delta Q = e_k$, where e_k has all its elements zero except the k^{th} one being 1. Then,

$$\Delta V = \sum_i \frac{\eta_{ik}\xi_i}{\lambda_i} \tag{12}$$

with η_{ik} the k^{th} element of η_i.

V-Q sensitivity at bus k,

$$\begin{aligned} \frac{\partial V_k}{\partial Q_k} &= \sum_i \frac{\xi_{ki}\eta_{ik}}{\lambda_i} \\ &= \sum_i \frac{P_{ki}}{\lambda_i} \end{aligned} \tag{13}$$

If all the eigenvalues are positive, V-Q sensitivities are also positive for all the buses, and the system is voltage stable. Negative eigenvalues of J_R will cause some buses to have negative V-Q sensitivities and therefore voltage instability. Zero eigenvalue of J_R is indicative of a system on the verge of voltage instability.

The participation factor of bus k to mode i is defined as,

$$P_{ki} = \xi_{ki}\eta_{ik} \tag{14}$$

From (13), P_{ki} indicates the contribution of the i^{th} eigenvalue to the V-Q sensitivity at bus k. The bigger the value of P_{ki}, the more λ_i contributes to V-Q sensitivity at bus k. For all the small eigenvalues, bus participation factors determine the areas close to voltage instability.

It is unnecessary to calculate all the eigenvalues of a practical system with several thousand buses. On the other hand, calculating only the minimum eigenvalue of J_R is not sufficient because there are usually more than one weak mode associated with different parts of the system, and the mode associated with the minimum eigenvalue may not be the most troublesome mode as the system is stressed. If we can determine the m smallest eigenvalues of J_R, we have obtained the m least stable modes of the system. If the biggest of the m eigenvalues, say mode m, is deemed a strong enough mode, the modes which are not calculated can be neglected because they are known to be stronger than mode m. In practice, it is seldom necessary to compute more than 5 to 10 smallest eigenvalues.

Reference 7 describes an efficient numerical method for computation of a selected number of smallest eigenvalues of the Jacobian matrix J_R associated with systems with several thousand buses. It also describes how the elements of J_R may be modified to include detailed models for generators, loads, and SVCs appropriate for voltage stability studies.

The results of the application of modal analysis to the test system of Figure 4 are summarized in Table II. The results provide eigenvalues associated with two weakest modes and their top five bus participations for the base case and the critical case. The areas affected by these modes are identified in Figure 8.

Table II. Two Weakest Modes and Bus Participations

Base Case				Critical Case			
$\lambda 1 = 27.8832$		$\lambda 2 = 41.1596$		$\lambda 1 = 0.0748$		$\lambda 2 = 25.3407$	
Bus #	P_{ki}	Bus #	P_{ki}	Bus #	P_{ki}	Bus #	P_{ki}
27	0.1923	12	0.9667	21	0.2721	27	0.2030
17	0.1657	13	0.0082	24	0.1591	17	0.1642
18	0.1518	27	0.0059	16	0.0119	18	0.1488
15	0.1130	11	0.0043	15	0.0077	15	0.1126
16	0.0990	14	0.0040	17	0.0056	16	0.0910

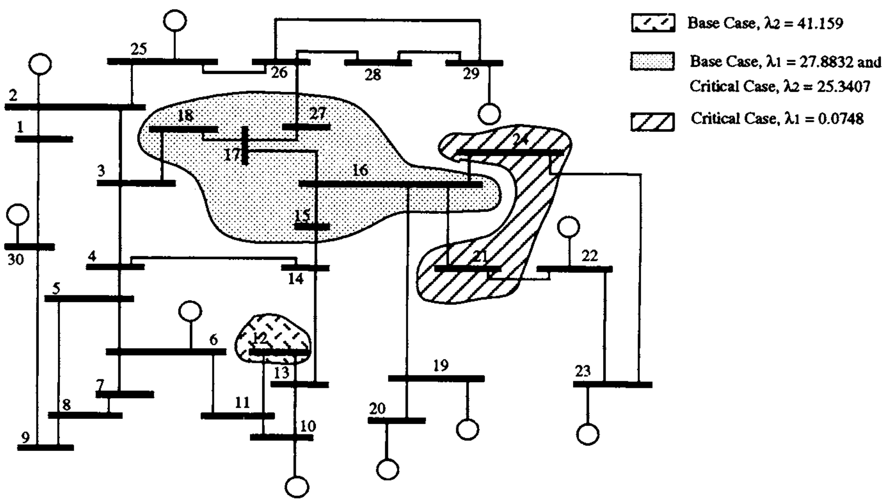


Figure 8: Areas Affected by Weakest Modes

As demonstrated in [7], the modal analysis approach, in addition to bus participation, can identify branch and generator participations. These provide useful information regarding factors influencing the voltage stability problem:

- Branch participations show which branches are important in the stability of a given mode. This provides insight into possible remedial actions as well as contingencies which may result in loss of voltage stability.

- Generator participations indicate which machines must retain reactive reserves to ensure stability of a given mode.

This approach has been applied successfully in [7] for voltage stability assessment of large complex systems.

Voltage stability indicator

In [10], a method for fast prediction of voltage instability and proximity to voltage collapse is proposed, based on the indicator L defined for load bus i as follows:

$$L_i = \left| 1 + \frac{V_{io}}{V_i} \right| \tag{15}$$

Where V_i is the actual complex bus voltage and V_{io} is the complex bus voltage when the generator bus voltages are kept the same as those under the present operating conditions and all the loads are removed.

L_i varies between 0 and 1. The bigger the value of L_i, the closer the bus is to voltage instability.

For the test system of Figure 4, Table III shows ranking of five load buses with highest L indices.

Table III. Five Buses with the Highest L Indices

Base Case			Critical Case		
No.	Bus #	L_i	No.	Bus #	L_i
1	27	0.0964	1	24	0.2361
2	15	0.0959	2	15	0.2079
3	24	0.0910	3	27	0.2014
4	17	0.0878	4	17	0.1862
5	18	0.0876	5	18	0.1826

Comparison with the results of sensitivity analysis (Table I) and modal analysis (Table II) shows that the L indicator approach does not identify all critical buses prone to voltage collapse, for example bus 21.

The advantage of the L indicator approach is its simplicity and computational speed. The modelling capability of the method is limited to that of conventional power flow analysis. This approach may be useful as a screening tool for rapidly identifying voltage weak buses.

D. Dynamic Analysis of Voltage Stability

Full dynamic simulation, using time domain analysis provides a useful complement to static analysis, and is useful for the following applications:

- Ensuring that the system trajectory following a contingency will in fact reach a stable equilibrium point;

- Gaining an understanding of the dynamic interaction between the generating units, network controls, loads, and ULTCs;

- Coordinating protection and controls with power system requirements; and

- Developing and testing remedial measures, such as automatic load shedding and ULTC blocking.

Extended transient/midterm stability programs and longterm dynamics simulation programs are ideally suited for dynamic analysis of voltage stability. In order to be able to simulate slow phenomena extending up to several minutes, implicit integration methods need to be used. This would allow use of large time steps without causing numerical stability. Equipment models should include ULTC action, load dynamics, and over/underexcitation protections and controls.

IV. CRITERIA

Most of the voltage stability criteria reported in the literature are based directly or indirectly on one or combination of voltage, reactive power, and active power margins. Others are based on indices that measure sensitivity of load bus voltage to change in active load power, load bus voltage to change in injected reactive power, or reactive power generated by all active sources to changes of load reactive power. Following are some of the reported criteria [4].

One of the criteria gaining wide acceptance in Europe is that developed in [8]. It is being implemented by Electricite de France (EDF) for on-line application [9]. The following is a brief description of the method:

- The system algebraic equations are linearized around the initial operating point and then the sensitivities of bus angles, load bus voltages, and generator bus reactive power to incremental changes to system active and reactive power demands are calculated.

- The demand is incremented until a generator reaches its control limit at which time the increment is recorded. This generator bus is converted to a load bus and the system equations are linearized around the new operating point.

- The process is repeated until voltage instability is detected. The active and reactive power margins are equal to the sums of increments in the respective components of power demands calculated in all the transition steps.

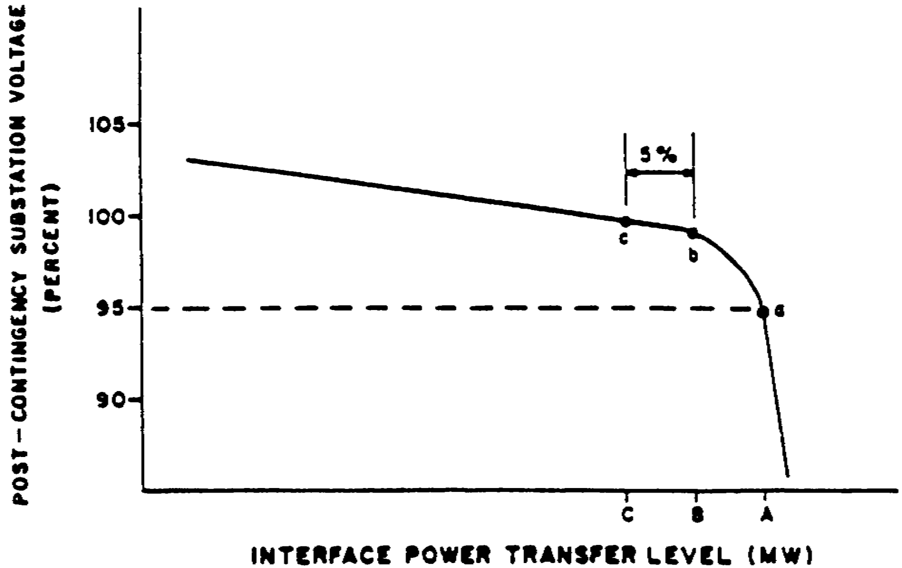
In addition, EDF has one of the most comprehensive on-line voltage control schemes. The system operating states are divided into three categories:

i) Normal state where "n" and "n-1" security levels are assessed,
ii) Alert state where only "n" security level is assessed, and
iii) Emergency state where some "n" voltages are out of their bounds.

Under normal or alert state, the control is done on the secondary and the tertiary levels. The secondary control action (regional) is decided based on on-line study of "n" and "n-1" contingencies, the data of which is derived using state estimation. The discrete control actions, e.g. topology changes, unit start-up, generation rescheduling, etc. are coordinated manually. Voltage profile control, however, is done automatically: The EHV system is divided into about 30 zones. The secondary voltage regulator of each zone modifies the AVR set points of the voltage controllers in their respective zone based on feedback measurement of the so called "pilot-bus" which is representative of the voltage profile of its zone. Each regional control centre is usually able to control its voltage profile using 3 to 5 pilot buses. The tertiary level control is usually coordinated between the national and the regional operators to coordinate the set points of the pilot buses or change in the major system topology. This decision is usually forecasted ahead of time for load changes.

Under emergency state, the operator may operate the generators at their maximum reactive power limit, block the on-load tap changer operation, reduce the distribution voltage by up to 5%, or order load shedding to avoid voltage collapse.

An example of a criterion based on the V-P relation of Figure 1 is that of New York Power Pool (NYPP) [4,13]. The pre and post-contingency voltage performance as a function of power flow across a major transmission interface is calculated using off-line load flow studies. Pre-contingency and post-contingency high and low voltage limits are monitored on many of the 345 kV buses and selected 230 kV buses in off-line studies as basis for NYPP planning criteria. The low limit is typically set at 95% of nominal voltage. The high limit ranges from 105 to 110% of nominal voltage. In addition, the leading edge of the V-P curve is identified as in Figure 9. The power transfer corresponding to that edge is then reduced by 5%. This reduced transfer level is compared to the pre-contingency transfer level corresponding to the point at which the post contingency voltage equals 95%. To ensure that a voltage constrained transfer limit is determined with a safe margin, the lower of the two power transfer levels from the foregoing comparison is selected as the transfer limit. Figure 9 shows a condition in which the allowable transfer level is controlled by the edge of the V-P curve rather than the 95% lower voltage limit.



(1) SMALL LETTERS a,b & c DENOTE POINTS ON THE CURVE, WHERE:

- a IS THE POINT OBTAINED AT 95% VOLTAGE:
- b IS THE POINT AT THE "LEADING EDGE OF THE CURVE"; AND
- c IS THE POINT OBTAINED WHEN POWER TRANSFERS ARE REDUCED BY 5% FROM THE LEADING EDGE

(2) CAPITAL LETTERS A,B & C DENOTE POWER TRANSFER LEVELS CORRESPONDING TO POINTS a,b, & c RESPECTIVELY.

(3) FOR THIS EXAMPLE, C WOULD BE THE VOLTAGE - CONSTRAINED INTERFACE TRANSFER LIMIT.

Figure 9

An example of a criterion based on the Q-V relation is that of B.C. Hydro, Canada [14]. The same criterion is used for planning and operation. Referring to Figure 10, a hypothetical variable reactive power source is assumed at a central bus (INGLEDOW) representing the area of concern under a predefined contingency. The variation in the post-contingency bus voltage (V) as a function of the injected reactive power (Q) is recorded in the form of the Q-V relation shown in Figure 11. A criterion was then established as follows:

i) A variable reactive power margin "A" must be provided between the voltage stability limit (the bottom of the curve) and the operating point. This margin is dependent on power transfer to the area under study. For B.C. Hydro's main load centre, the value of "A" must be at least 4.0 MVAr per 100 MW of total power transfer to the region.

ii) The voltage margin "C" between the voltage stability limit and the operating point must be at least 5%.

iii) The bus voltage corresponding to the stability limit must be less than 0.95 pu.

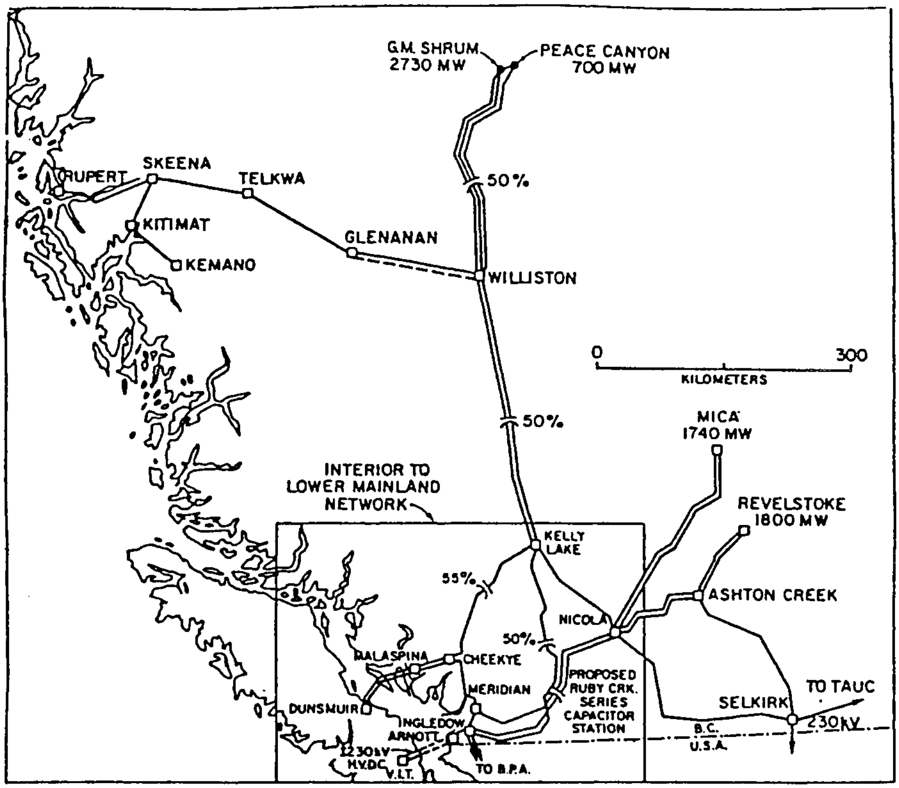


Figure 10: B.C. Hydro 500 kV Transmission System

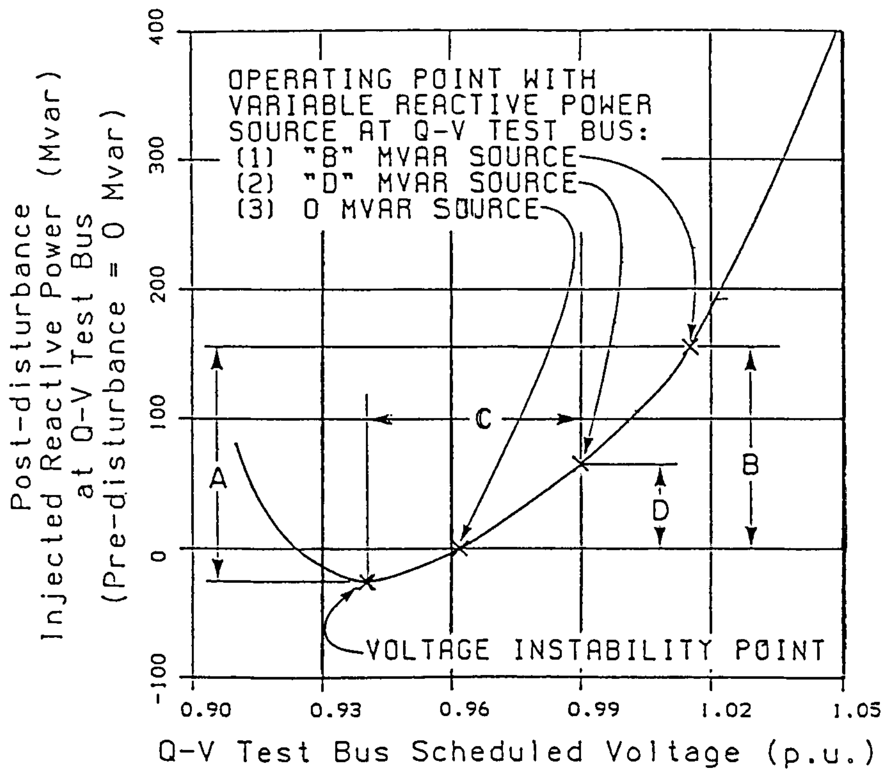


Figure 11: Q-V Curve Analysis Criteria

Recent planning studies concluded that item (iii) of the criterion results in inconsistent results, especially when the characteristics are such that the bottom of the curve is flat over a wide range of voltage. Another contributing factor to the inconsistency is the fact that voltage stability is limiting in more than one region of the system, which makes it difficult to base the criterion on the characteristic at only one representative bus. Accordingly, the criterion was recently modified to include items (i) and (ii) only while (iii) was eliminated.

One of the first utilities to investigate methods of analyzing voltage stability and implement related criteria is CPTE of Belgium. Reference [5] compares the various criteria considered by CPTE. The assessment is done using a load flow based program with the generators represented by a quasi steady state model linearized around the operating point. In this model, effects of incremental variations in active current, reactive current, and excitation voltage on terminal voltage are modelled taking excitation limits into account. The proximity to voltage instability could be assessed by any of the following criteria:

i) $Vi/Ei > 0.5/\cos((a-b)/2)$

where "Vi" is the set of bus voltages calculated from a power flow solution or by measurement, "Ei" is the set of open circuit voltages calculated by solving the network with all the loads removed and the generator active powers (except the slack bus) are reduced to zero, "a" is the system equivalent impedance angle calculated at bus "i" and "b" is the load power factor angle at the same bus.

ii) $(dQ_L/dQ_G) > 0$ at constant active power

This criterion indicates that for every operating point, voltage stability is ascertained if an incremental increase in reactive power demand is matched by a finite increase in generated reactive power. The criterion is tested by incrementing the reactive power demand at one bus or a group of buses while monitoring the change in the reactive power generated by all the sources (generators, SVC's, synchronous condensers, etc.).

iii) $(d|V|/|V|)/(dQ_L/Q_L) < 0$ at constant active power

This criterion is applied by incrementing the reactive power demand at one or more buses and the corresponding bus voltages are calculated. Both voltage and reactive power increments are normalized with respect to their corresponding initial values and then the above ratio is calculated.

iv) $P_L < P_{max}$ and $Q_L < Q_{max}$

The maximum active and reactive load limits of the network are similar to those explained earlier using the active dipole example. More details about the method are given in reference [5].

V. INCIDENTS OF VOLTAGE INSTABILITY/COLLAPSE

Invaluable lessons could be learned from the voltage instability and collapse incidents reported in the literature as to their causes and consequences. A number of these were selected for the purpose of this publication. The incidents are classified, below, according to the initiating cause which may or may not be voltage related but eventually would evolve to voltage collapse.

A. Load Increase

Load increase at a fast rate is considered to be the principal cause for the French system collapse of 19 December, 1978 [4], and the Tokyo system collapse of 23 July, 1987 [11].

On the morning of December 19, 1978, greater than anticipated temperature drop in France resulted in a rapid load increase of 4600 MW between 7 a.m. and 8 a.m. The resultant increase in power transfer led to increase in MW losses and to a remarkable increase in reactive power losses on the transmission lines connecting the Paris area to Eastern France. Some 400 kV lines were overloaded and severe voltage deterioration was observed for over 25 minutes. To ease the situation, some EHV/HV tap changers were blocked and 5% drop in distribution voltage was ordered in some areas. These actions were partly effective as the voltage on parts of the 400 kV system continued to decline and stabilized at about 350 kV. Shortly after, a 400 kV line was tripped by the action of its overload protection which, in turn, caused cascaded tripping of other 400 kV and 225 kV lines followed by wide spread strong oscillations over the entire French network.

A similar incident took place on a hot Summer day in Japan, where the temperature reached a record high of 39°C in the Tokyo area. The morning demand on the Tokyo Electric Co. (TEPCO) system of that day reached 39,100 MW and dropped to 36,500 MW shortly afternoon (lunch hour). By 1:00 p.m. the demand reached 38,200 MW. Additional generation and reactive power support were called upon to balance the increase in active and reactive power demand until the 500 kV voltage stabilized between 510 and 520 kV. Starting at 1:00 p.m. the load began to increase at a remarkable 400 MW per minute. As a result, the voltage started to decay gradually even though additional shunt capacitors (eventually all of them) were brought into service. This is primarily because the increase in reactive power losses was always higher than the discrete increase in shunt compensation especially that the reactive power contribution of the shunt capacitors is reduced by the square of the voltage ratio. By 1:10 p.m. the power demand reached 39,300 MW accompanied by continuing decay of voltage down to 74% in the western part and 78% in the central part of the system by 1:19 p.m. when three major substations were tripped by the operation of protective relays. As a result, 8168 MW of load was lost affecting 2.8 million customers. 60% of the lost load was restored in about 17 minutes and the rest were restored in about 3 hours and 20 minutes.

B. Load Tripping

Load tripping, in comparison to load increase, may be surprising to many as a possible cause of voltage collapse. It should be noted, however, that the reason load increase initiated the voltage problems described above is the increase in power transfer to the load area without proper voltage support especially if the load characteristics at the receiving end is stiff (e.g. constant power). If load tripping happens towards the sending end and result in an increase in the transfer to remote areas, the result can be the same if proper voltage support is not provided. In this case, however, a soft load characteristics at the sending end (e.g. constant impedance) can aggravate the situation.

A classic example is the July, 1979 collapse of the North Coast region of B.C. Hydro, Canada (the western part of the radial section out of Williston substation, Figure 10). For better display, a single line diagram of the affected area is shown in Figure 12. Prior to the disturbance, a trouble shooting procedure made it necessary to switch the excitation of seven out of eight generators at Kemano station to manual. The main load of Kemano station is an aluminum smelter at Kitimat substation (600 MW). The power transfer out of Kitimat to the integrated system was 150 MW.

The disturbance was initiated by the tripping of 100 MW potline load at the smelter, causing an immediate increase of transfer out of Kitimat to 250 MW. With the generators at Kitimat on manual excitation voltage support for the increased transfer was inadequate, bringing the voltage in the area down. The smelter load is practically constant impedance which caused the power consumption at the smelter to drop by the square of the voltage. This, in turn, caused the power transfer to increase further bringing the voltage down even further. The process continued slowly in a monotone manner until the power transfer reached 390 MW and Skeena 500 kV voltage reached about 250 kV in one minute from the beginning of the disturbance and before line relaying isolated the region. Disturbance records captured at the Kemano generating station showed a fairly steady station

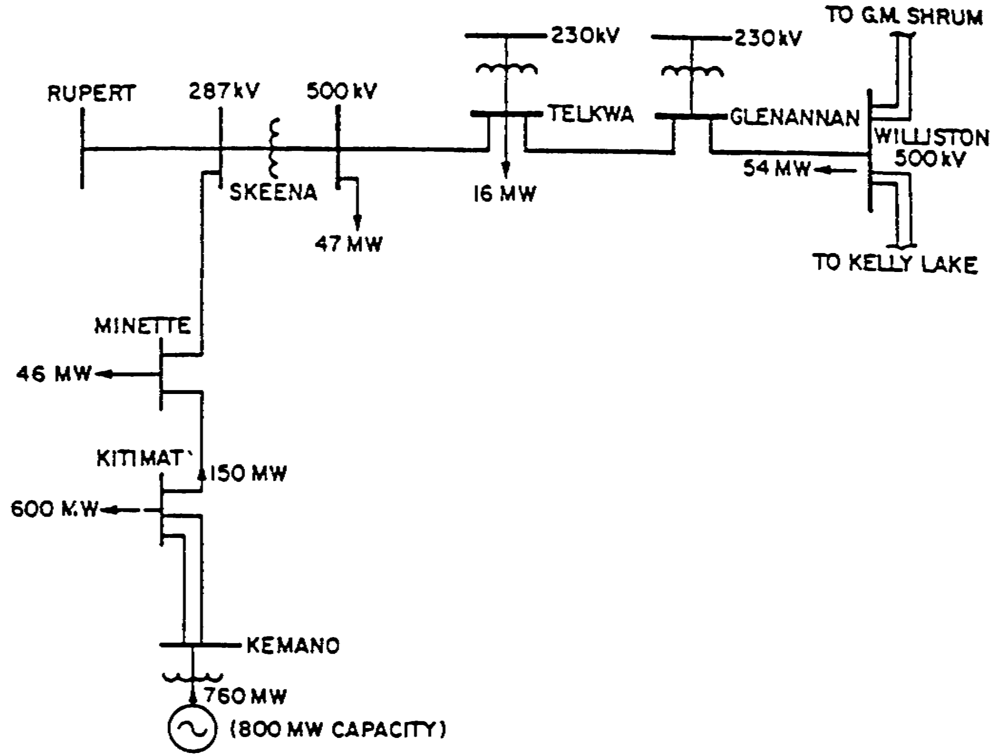


Figure 12: North Coast System - Single Line Diagram and Power Flow Prior to July 1979 Voltage Collapse Incident

output within the observed duration of the disturbance which excludes the possibility of machine angle stability as one may suspect.

C. Loss of Generation

Loss of generation in a certain zone of a network may deteriorate the voltage stability in two ways:

1. The balance of the power may have to be called upon from remote locations which may increase the transmission reactive losses considerably depending on the prior loading of the interconnections.

2. Loss of generators may result in severe shortage of reactive power sources which could leave the system with inadequate voltage support.

The January 12, 1987 incident on the French system, which affected the whole western part of France, is a good example for the latter: The pre-disturbance operating reserve was 5900 MW (approximately 7% of the system capacity). Between 10:55 a.m. and 11:42 a.m., three out of four thermal units at a generating station (Cordemais) located on the western region of the French system tripped by protective relaying action. Thirteen seconds later, and before emergency gas turbines were brought in service, the fourth unit tripped upon excitation overcurrent protection action as the fourth unit tried to control the voltage solely. Additional voltage support duties were picked automatically by other generators resulting in a sequence of generator trippings because of excitation overload. Nine units were tripped in 5 minutes following the outage of the first four generators resulting in a total of 9000 MW of lost generation. By 11:50 a.m., the voltage level of the 400 kV western part of the system stabilized at less than 300 kV and as low as 240 kV in some parts. It should be noted that in spite of the generation deficiency, the frequency did not change significantly which indicates a significant dependence of load characteristics on voltage. The voltage profile was restored by tripping 1500 MW of load at the western most part of the system. Figure 13 summarizes the results of the incident [4].

An example of loss of generation that result in large MW transfer and voltage instability is the December 28, 1982 in Florida (Refer to Figure 14): The East Coast 500 kV system was at an early stage of development in 1982. There were two 500 kV tie lines between Florida and Georgia but there were no 500 kV transmission between North and South Florida yet. At 11:33 a.m., Turkey Point #3 carrying 700 MW was tripped. At that time, Florida load was approximately at 60% peak and maximum import. The increase in power transfer over the tie lines to Florida caused voltage drop of 8.6% on the 230 kV system in North Florida. One minute later, Sanford #3 (in the North) tripped on maximum excitation limiter / over excitation protection resulting in an additional loss of 89 MW and 104 MVAr. As modest as it is, the latter caused an additional voltage drop of 9% on the 230 kV northern system. As the voltage deteriorated, out of step relays operated and separated Northeast Florida followed by a loss of another unit (Putnam #1). The separation and loss of generation resulted in the loss of about 11% of the system load for 36 minutes.

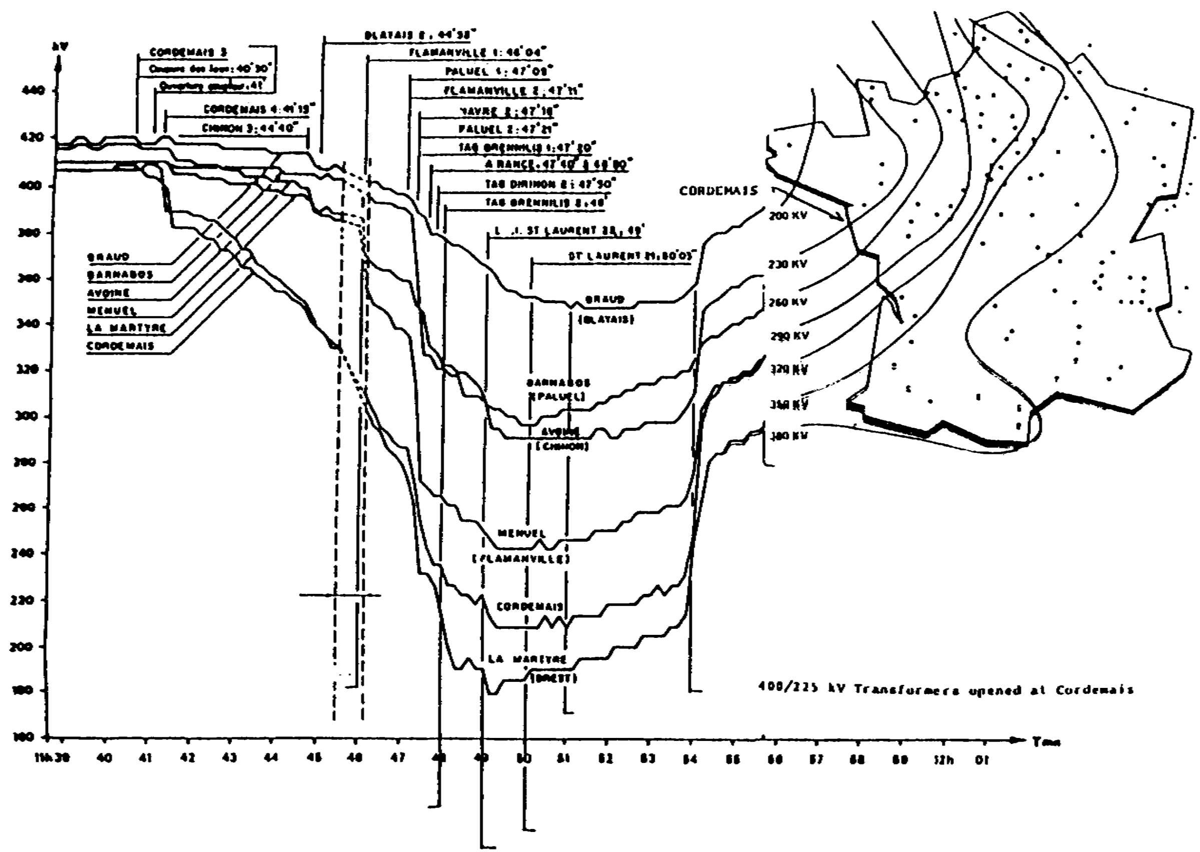


Figure 13: Details of the Power Failure of January 12, 1987

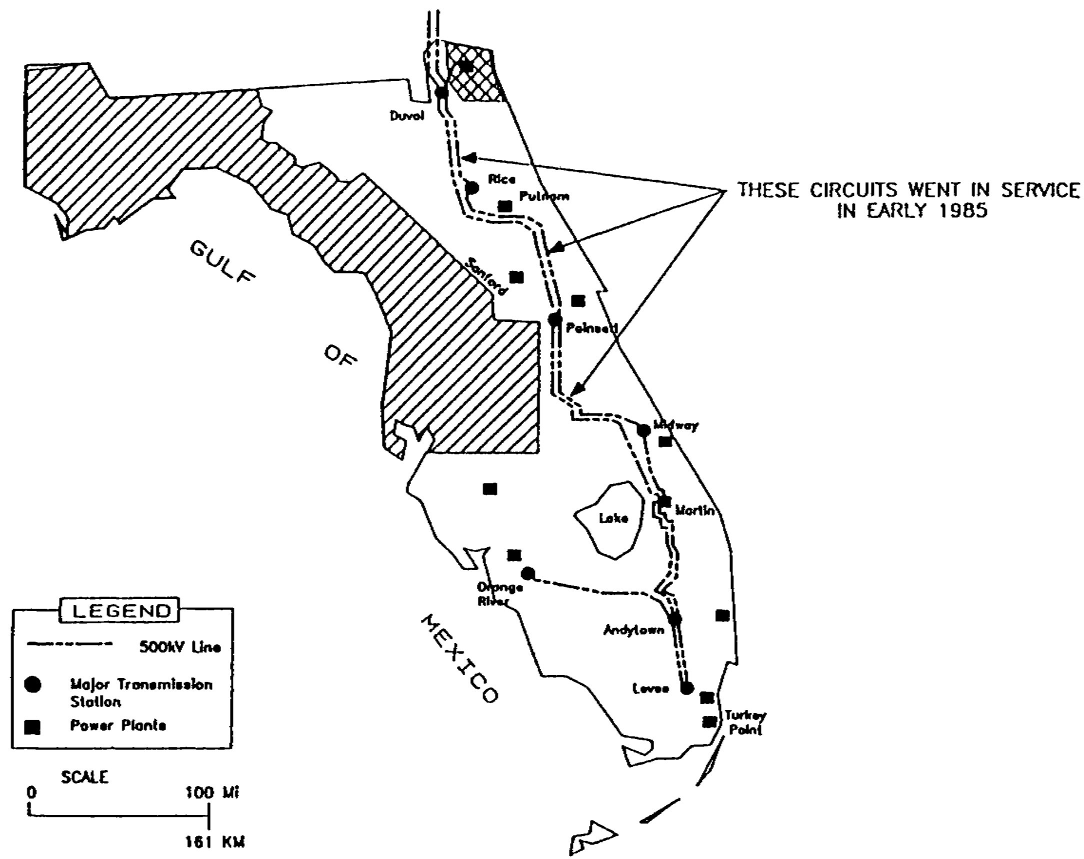


Figure 14: The FPL 500 kV Transmission System

D. Loss of Transmission Line(s)

Loss of parts of the transmission system at a time of heavy transfer may result in overloading the remaining transmission far beyond its surge impedance loading and result in voltage collapse.

There are many documented examples, but we picked the May 17, 1985 one in Florida because of the familiarity with the system that the readers might already have built up in the preceding section: By the time of the incident, the 500 kV system was completed. The pre-disturbance loading of Southeastern Florida was 4294 MW with 53% of the power being imported.

At 11:36 a.m., an intense grass fire spread across the 500 kV transmission corridor causing a series of phase to ground faults. All three 500 kV circuits north of Andytown substation tripped within 10 minutes. This caused a shift in the power flow to three 230 kV and two 138 kV lines. Approximately 0.5 second later, one of the 230 kV lines tripped causing a large voltage drop. The remaining transmission circuits and two generators were tripped within the next 3.5 seconds, mostly by impedance protection. This resulted in isolating the Southeast Florida area with a generation deficiency of approximately 80% for about 3.5 hours. The voltage in the isolated area dropped to 40-50% of nominal. It should be noted that the underfrequency load shedding scheme did not operate properly because of the cut-off voltage characteristics of the underfrequency relays. This scheme was upgraded in 1986.

VI. LESSONS LEARNED FROM THE DISTURBANCES

A. The voltage instability phenomenon generally manifests as a slow dynamic decay in voltage. The rate of decay depends mainly on load characteristics, and the responses of voltage regulators and protective devices. The time frame to collapse could range from few to many minutes.

B. In just about all the cases, the situations were aggravated by at least one protective device operation based on local equipment related signal. Tripping the equipment made the situation only worse from a system view point. Therefore, there is an urgent need for better system wide coordination philosophies between protective and control devices to better reflect overall system, rather than just equipment, remedial needs.

C. No abnormal faults are necessary to initiate voltage instability/collapse. The Japanese and the French incidents are good examples.

D. Proper load modelling is essential for accurate analysis of voltage collapse. Load characteristics could be such that voltage and load could decay until the system voltage stabilizes at low magnitude. This low magnitude depends to a large extent on the voltage regulator limits. The Japanese incident alerted the industry to the high reactive power demands of modern air conditioners at low voltage. On the other extreme, the B.C. Hydro incident showed the adverse effect of constant impedance loads when located near the sending end.

E. Excessive dependence on shunt capacitors for reactive power support and voltage control could have detrimental effects. In the Japanese incident, switching a massive amount of shunt capacitors did not stop the voltage decay. Shunt compensation can be made most effective by the proper coordination of a mixture of shunt capacitors, static VAr systems, and synchronous condensers [3].

F. Load shedding and blocking of automatic tap changers are the most effective ways to avoid voltage collapse. The B.C. Hydro case, however, showed that load tripping must be done at the proper location in order to be effective. Also, power system analysts have to ensure that extensive load tripping does not result in high voltage and subsequent tripping of facilities by over voltage protection. This happened in the July 13, 1977 incident in New York [4].

VII. PREVENTION OF VOLTAGE COLLAPSE

This section identifies measures that can be undertaken in the planning and operation of power systems to mitigate voltage stability problems. In addition, one application of a special protection scheme for prevention of voltage collapse is described.

Planning measures [12]

A. Reactive power compensation: Voltage stability characteristics of power systems are significantly affected by reactive power compensation of the transmission network. Adequate voltage stability margins should be ensured for the most onerous system condition (for which the system is to be designed to operate satisfactorily) by proper selection of the type, size, and location of reactive power compensation.

If generating stations are far removed, it may be necessary to use regulated compensators (synchronous condensers, SVCs) or series capacitors.

B. Load compensation of generator AVRs: Depending on the relative location of generating units with respect to load centres, it may be advantageous to provide load (or line crop) compensation to automatic voltage regulators. This would in effect move the point of constant voltage electrically closer to the loads, thereby improving voltage stability.

C. Coordination of protection and controls: Examination of actual system disturbances indicate that one of the causes of voltage collapse is lack of coordination between generating unit protections/controls and power system requirements. Adequate coordination should be ensured by performing dynamic simulation studies.

D. Undervoltage protection schemes: To cater for unplanned or extreme situations, it may be desirable to provide special protection schemes such as under-voltage load shedding and ULTC blocking. Such schemes would prevent widespread system collapse.

Operating measures

A. Stability margin: System should be operated with adequate voltage stability margin by appropriate scheduling of reactive power resources and voltage profile. There are at present no universal guidelines for selection of the degree of margin and the system parameters to be used as indices. These are likely to be system dependent and may have to be established based on the characteristics of the individual system.

If the required margin cannot be met by using available reactive power resources and voltage control facilities, it may be necessary to limit power transfers and startup generating units to provide voltage support at critical areas.

B. Spinning reserve: Adequate spinning reactive power reserve must be ensured, if necessary, by operating generators at moderate or low excitation and switching-in shunt capacitors to maintain desired voltage profile.

C. Operators' action: Operators must be able to recognize voltage stability related symptoms and take appropriate remedial actions such as voltage and power transfer controls and, possibly as a last resort, load curtailment. Operating strategies that prevent voltage collapse need to be established. On-line monitoring and analysis to identify potential voltage stability problems and possible remedial measures would be invaluable in this regard.

Voltage collapse protection scheme [4,12]

In special cases, it may be necessary to provide protection schemes for prevention of voltage collapse. The following is an example of such a scheme which has been implemented by Ontario Hydro.

Because of delays in obtaining approval to build 500 kV transmission lines, the Ottawa area in Eastern Ontario is at present supplied largely by 230 kV transmission. In order to prevent voltage collapse due to loss of a critical 230 kV circuit under heavy load periods, a coordinated scheme consisting of the following has been used as a stop-gap measure:

- Fast auto reclosure of major 230 kV circuits supplying the area;
- Automatic load rejection;
- Automatic switching of shunt capacitors;
- Automatic blocking of load tap changers.

The fast auto reclosure (0.9 s to 1.3 s) is used as a first measure to maintain voltage within acceptable limits. If reclosure is successful, voltage recovers and the system returns to normal. If reclosure is unsuccessful, depending on how low the voltage drops, load rejection may be triggered, followed by capacitor switching and possibly LTC blocking.

The automatic load shedding provides for up to 9 blocks for loads totalling 750 MW to be rejected, depending on load level. It consists of a two-tiered rejection scheme:

- Fast rejection can be armed by operator action from an attended master station and will trip if local station voltage drops below a preset value for a minimum time period (1.5 s);

- Normal rejection will always be armed and will trip load if voltage and time limits are violated (10 s);
  Used for protection in the event of unforeseen circumstances.

The automatic capacitor switching provides for switching (on/off) of a total of 36 capacitor banks in 17 transformer stations. the capacitors are switched in staggered blocks with time settings ranging from 1.8 s to 8.0 s, so that only the required amount of compensation is switched.

The automatic LTC blocking at 14 transformer stations provides for blocking of tap changers when the local HT voltage drops below a present value for a specified time, and unblocking when voltages recover for a specified time.

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