

*Western Electricity Coordinating Council*

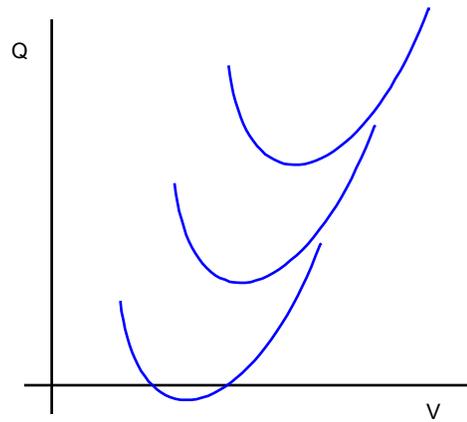
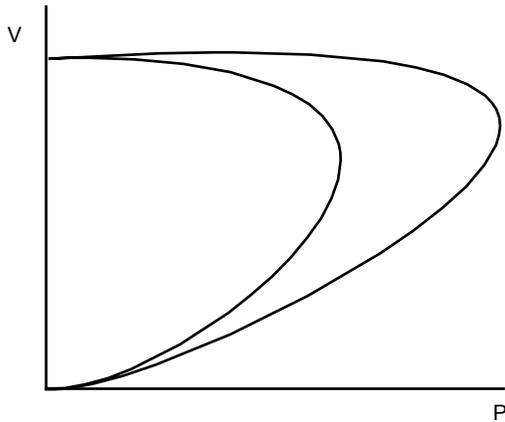
**Voltage Stability Criteria,  
Undervoltage Load Shedding Strategy,  
and  
Reactive Power Reserve  
Monitoring Methodology**

**May 1998**



# VOLTAGE STABILITY CRITERIA, UNDERVOLTAGE LOAD SHEDDING STRATEGY, AND REACTIVE POWER RESERVE MONITORING METHODOLOGY

## FINAL REPORT



May 1998

Prepared by

Reactive Power Reserve Work Group (RRWG) \*  
Technical Studies Subcommittee  
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# 1. EXECUTIVE SUMMARY

This is a previous Process of Western Systems Coordinating Council (WSCC) that has been adopted for use by WECC pursuant to the WECC Bylaws, Section 2.4, Transition.

On July 2, 1996, and August 10, 1996, two major disturbances occurred within the Western interconnected region. Both of the disturbances resulted in significant loss of load and generation throughout the region. Each of the disturbances was initiated by different events in different locations within the Northwest area of the Western Interconnection. Two disturbance reports were generated due to these disturbances. The first report was entitled, "WSCC Disturbance Report for the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996." The second report was entitled, "WSCC Disturbance Report for the Power System Outages that Occurred on the Western Interconnection on August 10, 1996."

Recommendations from the two reports identified several reliability issues which were to be investigated. Two issues identified in the disturbance reports pertinent to this report are reactive power margin studies and undervoltage load shedding schemes. The Technical Studies Subcommittee (TSS) met on November 8, 1996 and formed the Reactive Power Reserve Work Group (RRWG) to address reactive power margin issues.

The RRWG identified the following issues as critical to addressing the reactive power reserve topic:

- Develop a methodology for conducting reactive power reserve studies.
- Develop reactive power reserve requirements.
- Investigate and report on real-time voltage stability assessment methodologies.
- Determine if it is possible to design a generic undervoltage load shedding scheme.

The main purpose of this report is to address technical issues regarding reactive power margins and voltage stability criteria for all member systems. Other important and related issues, such as equity and financial responsibility, are beyond the scope of the RRWG's work at this time. These issues can be dealt with by the RRWG or other appropriate committees after the technical review has been completed. In this report "member system" refers to the WECC member

system which is either a control area, a transmission owner, or a transmission operator.

Reactive power margins and voltage stability criteria cover the period after the transient oscillations have damped out to before the operator can take manual actions and before area interchange schedules can be adjusted. This is beyond the transient time period; therefore, transformer load tap changers would have time to adjust. Transient voltage collapse due to angular instability (e.g., out-of-step conditions) is not addressed in this report. It is assumed that transient stability simulations for the contingencies considered have shown that the system would be stable and meets the WECC Reliability Criteria.

Following is a summary list of RRWG recommendations:

1. Both P-V and V-Q methodologies should be used to assess margin. Member systems may use either method for general voltage stability evaluation, contingency screening, etc.; however, voltage stability margins must be demonstrated by both P-V and V-Q analyses.
2. Each member system must plan and operate its system to maintain the minimum levels of margin specified in Table 1. Uncertainties in data, equipment performance, and network conditions (see Section 2.3) should be considered in the base case prior to applying Table 1.
3. Proper mixture of static and dynamic reactive power support based on the methodology described in this report should be provided (see Section 9).
4. Each member system must conduct studies based on the methodologies described in this report and document the following information:
  - (a) List of critical buses to be monitored
  - (b) List of worst contingencies
  - (c) Required reactive power margin at each critical bus
  - (d) WECC base case name
  - (e) Major path flows
  - (f) V-Q and P-V plots
  - (g) Important study assumptions

This information should be sent to the staff and will be part of a WECC catalog which includes the above information for all member systems.

5. The RRWG makes the following recommendations regarding policy issues:
  - The Voltage Stability Criteria should apply to each individual system's internal criteria as well as limiting the impact to a member system caused by another member system. The criteria includes the following provisions for application to internal systems:
    - (a) Controlled load shedding is allowed for Performance Level A contingencies in order to meet the margins specified in Table 1.
    - (b) The margins in Table 1 do not have to be met if (a) the local area is radial or is a local network and (b) the contingency under consideration does not cause voltage collapse of the system beyond the local area.
  - A member system may require margins greater than what is shown in Table 1 considering the uncertainties listed in Section 2.3; however, the additional margin cannot be imposed on other member systems unless technical justifications are provided and TSS approval is obtained.
6. Each member system should evaluate its need for an automatic undervoltage load shedding program.
7. Study models should be as detailed as feasible.
8. Accurate load models are crucial to this analysis. If actual performance data is unknown, load tests should be conducted. The use of a load synthesis program would be helpful for formulating load models using load test results or performance data. Until more accurate load models are available, loads should be modeled as constant MVA. Accurate power factors for the loads should also be used.
9. Reactive power margins must be monitored and maintained in real-time using either pre-determined tables or nomograms, or software utilizing real-time data. The BPA and EPRI methodologies for monitoring power reactive power reserves are endorsed.

10. The Council should pursue (a) the acquisition of a program for analysis of load modeling, such as the EPRI Load Synthesis Program (LOADSYN), and (b) the development of a long-term, fast-time domain simulation option for the GE and PTI programs.
11. Training materials encompassing the broad spectrum of reactive power issues should be developed for dispatchers. Dispatchers should be given clear instructions on how to maintain adequate reactive power reserves and corrective strategies to restore reactive power reserves to proper levels.

## **2. RECOMMENDATIONS**

The RRWG has examined various issues with regard to establishing a regional voltage stability criteria and makes recommendations in the following seven areas: Study Methodology, Voltage Stability Criteria for the Western Interconnected System, Consideration of Uncertainties for Establishment of the Voltage Stability Criteria, Software Programs and Models, Undervoltage Load Shedding Strategy, Methodology for Measuring Reactive Power Reserve in Real-Time, and Operator Training.

### **2.1 Study Methodology**

At a minimum, each WECC member system shall conduct P-V and V-Q analyses to ensure that the minimum required margins are met. Sole reliance on either P-V or V-Q analysis is not sufficient to assess voltage stability and proximity to voltage collapse. Each analysis is needed to confirm the results of the other (i.e., P-V analysis is needed to confirm the results of V-Q analysis and vice versa). Member systems may use either method for general voltage stability evaluation, contingency screening, etc.; however, voltage stability margins must be demonstrated by both P-V and V-Q analyses. Details of the V-Q and P-V study methodologies are given in Section 7 and Section 8, respectively.

In addition to P-V and V-Q analysis, full, long-term dynamic simulations, fast quasi-dynamic simulations [30], modal analysis [9] and security-constrained optimal power flow (OPF) analyses are valuable tools for providing insight into the voltage instability and collapse phenomenon. Member systems may use methods other than the V-Q and P-V analyses for exploratory purposes to gain more insight; however, the amount of margin must be demonstrated by both the V-Q and P-V analyses as described in this report.

Voltage stability criteria, as recommended in this report, shall apply equally to studies of interfaces and load areas. Interfaces include major WECC paths, tie lines with neighboring systems, and critical paths within a system.

The RRWG recommends that the Reliability Subcommittee

- modify the Council's Reliability Criteria to include margins as described in this report; and

- add guidelines for conducting P-V and V-Q studies in the WECC Reliability Criteria as described in this report.

## **2.2 Voltage Stability Criteria for the WECC System**

The Council's voltage stability criteria are specified in terms of real and reactive power margins. All member systems must provide the minimum margins specified in Table 1 considering the uncertainties listed in Section 2.3. The margin for N-0 (base case) conditions must be greater than the margin for Performance Level A to allow for unforeseen increases in load or interface flows without remedial action schemes which would be activated during contingency conditions but not during normal conditions. Each member system must examine the items listed in Section 2.3 to determine the required margin for its system.

Criteria noted in Table 1 apply equally to the system with all elements in service as well as the system with one element removed and the system readjusted. System elements include any facility, such as a generator, transmission line, transformer, reactive power source, etc. For the purposes of voltage stability analysis, the element, the outage of which reduces the margin the most, should be removed from the study case and the system readjusted following that outage. System adjustments after one element is removed in the base case (for Performance Levels A-D analyses) include all adjustments that can be made within 60 minutes to bring the system to the next acceptable steady state operating condition following the removal of the element (e.g., generation redispatch, start up of new generation, phase shifter and tap changer adjustments, area interchange adjustments, etc.).

The margin should be provided at all critical buses during all stressed system conditions. Stressed cases represent worst-case conditions for various load levels and interface flows such as

1. Peak load conditions with maximum generation
2. Low load conditions with minimum generation
3. Maximum interface flow conditions with worst load conditions.

The RRWG recommends that no less than a 1 in 2 year probability load forecast for voltage stability studies of load serving areas should be used. The 1 in 2 year occurrence load forecast (also referred to as a "50/50" or

average load forecast) represents a forecast with a 50% chance of being exceeded in each forecast year.

Generation patterns, load levels, load characteristics, generator reactive power capability, transformer tap changers, and interface flows in the study area and neighboring systems are some of the key parameters for voltage stability studies. Studies should be conducted to verify that the system is transiently and dynamically stable. This is important to demonstrate that there is no angular instability causing voltage collapse.

Determination of credibility for contingencies is based on the definitions used in the WECC Reliability Criteria. The contingencies to be studied include the outage of all system elements, such as lines, generators, reactive power devices, etc., that would impact the required margins. Appropriate measures must be taken to ensure that the margin criteria are met. For the V-Q methodology, the reactive power margin is measured from the bottom of the V-Q curve to the V axis (see Figure 7.1). If reactive power compensation is used, the margin is from the bottom of the V-Q curve to the intersection of the V-Q curve and the compensation characteristic. In the P-V methodology, the MW margin is measured from the nose point of the P-V curve to the operating point on the P-V curve (see Figure 8.1). Sections 7 and 8 provide detailed description on V-Q and P-V methodologies to measure margin, respectively.

The addition of sufficient system facilities, such as switched shunt capacitors, synchronous condensers, transmission lines, etc., or implementation of appropriate operating procedures or remedial action schemes, as applicable to each Performance Level, must be provided in order to maintain the required margin at all critical buses. Consistent with the WECC Reliability Criteria, load shedding is not allowed for Performance Level A to meet the required minimum margin for contingencies in one member system affecting other member systems. However, for application of the criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system).

The criteria includes the following provisions for application to internal systems:

- Controlled load shedding is allowed for Performance Level A contingencies in order to meet the margins specified in Table 1.
- The margins in Table 1 do not have to be met if (a) the local area is radial or is a local network and (b) the contingency under consideration does not cause voltage collapse of the system beyond the local area.

Although examples of radial systems and local networks are provided in Section 5, the definitions provided by the Reliability Subcommittee for radial systems and local networks should be used for application of the Voltage Stability Criteria.

**Table 1**

**WSCC VOLTAGE STABILITY CRITERIA<sup>(\*)</sup>**

<b>Performance Level</b>	<b>Disturbance (1)(2)(3)(4)</b> <b>Initiated By:</b> Fault or No Fault DC Disturbance	<b>MW Margin</b>  <b>(P-V Method)</b>  (5)(6)(7)	<b>MVAR Margin</b>  <b>(V-Q Method)</b>  (6)(7)
<b>A</b>	Any element such as: One Generator One Circuit One Transformer One Reactive Power Source One DC Monopole	≥ 5%	Worst Case Scenario (8)
<b>B</b>	Bus Section	≥ 2.5%	50% of Margin Requirement in Level A
<b>C</b>	Any combination of two elements such as:  A Line and a Generator A Line and a Reactive Power Source Two Generators Two Circuits Two Transformers Two Reactive Power Sources DC Bipole	≥ 2.5%	50% of Margin Requirement in Level A
<b>D</b>	Any combination of three or more elements such as: Three or More Circuits on ROW Entire Substation Entire Plant Including Switchyard	> 0	> 0

- (1) This table applies equally to the system with all elements in service and the system with one element removed and the system readjusted (see Section 2.2).
  - (2) For application of this criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system).
  - (3) The list of element outages in each Performance Level is not intended to be different than the Disturbance Performance Table in the WECC Reliability Criteria. Additional element outages have been added to this table to show more examples of contingencies. Determination of credibility for contingencies for each Performance Level is based on the definitions used in the existing WECC Reliability Criteria.
  - (4) Margin for N-0 (base case) conditions must be greater than the margin for Performance Level A.
  - (5) Maximum operating point on the P axis must have a MW margin equal to or greater than the values in this table as measured from the nose point of the P-V curve for each Performance Level.
  - (6) Post-transient analysis techniques shall be utilized in applying the criteria.
  - (7) Each member system should consider, as appropriate, the uncertainties in Section 2.3 to determine the required margin for its system.
  - (8) The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecasted loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.
- (\*) Table 1 is an excerpt from the WSCC Reliability Criteria for Transmission System Planning in effect at the time of this document's approval. The most current version of the Council's Table of Allowable Effects on Other Systems should be referred to when conducting studies.

## 2.3 Consideration of Uncertainties for Establishment of the Voltage Stability Criteria

Table 1 specifies the minimum required margins for each member system. Prior to applying Table 1, the member system should consider, as appropriate, the uncertainties a-r [28] listed below. These uncertainties relate to unknowns in data, equipment performance, and network conditions. This list will be modified as member systems gain experience in applying Table 1 and identify new uncertainties or agree that some uncertainties are already included in Table 1.

- (a) Customer real and reactive power demand greater than forecasted
- (b) Approximations in studies (Planning and Operations)
- (c) Outages not routinely studied on the member system
- (d) Outages not routinely studied on neighboring systems
- (e) Unit trips following major disturbances
- (f) Lower voltage line trips following major disturbances
- (g) Variations on neighboring system dispatch
- (h) Large and variable reactive exchanges with neighboring systems
- (i) More restrictive reactive power constraints on neighboring system generators than planned
- (j) Variations in load characteristics, especially in load power factors
- (k) Risk of the next major event during a 30-minute adjustment period
- (l) Not being able to readjust adequately to get back to a secure state
- (m) Increases in major path flows following major contingencies due to various factors such as on-system undervoltage load shedding
- (n) On-system reactive resources not responding
- (o) Excitation limiters responding prematurely
- (p) Possible RAS failure
- (q) Prior outages of system facilities
- (r) More restrictive reactive power constraints on internal generators than planned.

The RRWG further recommends that member systems consider the consequences of a voltage collapse in determining the amount of required margin in the study area.

The BPA Blue Ribbon Panel report (see Appendix F) states that:

“The Panel is not convinced that a study margin is sufficient if key generators are at their reactive limits. However, the studies presented indicated margin existed on a number of key generators.”

Although the RRWG does not make a specific recommendation regarding this issue, member systems should evaluate the consequence of key generating units at their reactive power limits.

The proper amounts of static and dynamic reactive power resources are needed to (1) supply reactive power requirements of customer demands, (2) supply reactive power losses in transmission and distribution systems, and (3) provide adequate system voltage support and control. The RRWG recommends that:

1. The best method for determining the proper mixture of static and dynamic reactive power is to conduct dynamic simulations using the current GE or PTI programs. Member systems which already have the capability to conduct long-term dynamic simulations should use dynamic simulations to determine the required mixture of static and dynamic reactive power support.
2. If a long-term dynamic simulation option is not available, the governor/post-transient power flow methodology outlined in this report should be used.
3. The Council should pursue the development of long-term, fast-time domain simulation option for the GE and PTI programs.

Section 9 provides more detail regarding the methodologies for determining the proper amount of static and dynamic reactive power support.

## **2.4 Software Programs and Models**

It is recommended that a governor power flow method (also known as a post-transient program) be used for conducting P-V and V-Q analyses to determine the margin; otherwise, a standard power flow program can be used. A governor power flow program usually consists of a "standard" power flow program with accompanying software routines to properly model the post-transient period. System performance should be evaluated for time periods between 0.5 minute to several minutes after a contingency. For study cases involving changes in generation, voltage stability should be checked for final generation pick up after Automatic Generation Control has taken place. Transient voltage collapse due to angular instability (e.g., out-of-step conditions) is not addressed in this report. If out-of-step conditions cause formation of controlled islanding, the islands should first be identified and formed before post-transient simulations can be performed for each separate island. It is assumed that transient stability simulations for the

contingencies considered have shown that the system would be stable and meets the WECC Reliability Criteria. The methodology for performing post-transient power flow studies is included in Section 6.

Dynamic simulation can be performed with a “standard” stability program. Long-term dynamic simulations require accurate modeling of non-linear speed droop governor models, load models with motor representations, and slow acting devices such as transformer tap changers, overexcitation limiters and overexcitation protection, thermostatically-controlled loads, automatic generation control, and energy supply systems [17].

It is recommended that each member system study its loads and conduct tests, if practical, to determine more accurate load models. The study area should be modeled in as much detail as is feasible. It is further recommended that bulk power delivery LTC transformers, distributions system equivalents, voltage sensitive and dynamic loads (e.g., induction motors) be modeled. If accurate load models are not available, loads should be modeled as constant MVA. Accurate power factors for the loads should also be used. Additional detailed representation of the lower voltage distribution system is permitted. However, the system representation used to establish voltage stability margins must be available to all Council members for the margins to be recognized. For the purpose of testing the margins, facility thermal ratings should be ignored to achieve the increase in interface flows. A list of facilities which are overloaded should be recorded, but no mitigative measures are required to resolve the overload problems. Please refer to a document entitled, “Voltage Instability Analysis” and references [12,17,20,25,26] for further information on simulation modeling.

The Council should pursue the acquisition of a software program for analysis of load data such as the EPRI Load Synthesis (LOADSYN) Program. The use of such a program would facilitate the formulation of load models for various studies.

The Council should also pursue the development of a long-term, fast-time domain simulation option (similar to the EPRI ETMSP program) for the GE and PTI programs. The fast-time domain option is about 200-1000 times faster than a full, long-term stability program and would allow analysis of numerous contingencies in a relatively short time. This option will enhance the use of long-term dynamic simulations.

## **2.5 Undervoltage Load Shedding Strategy**

Each member system shall evaluate its system to identify the need and requirements for implementing an undervoltage load shedding scheme. The RRWG does not recommend a standard load shedding program for the entire WECC system. Member systems should refer to the guidelines provided in Section 10 of this report for evaluating the need for implementation of an undervoltage load shedding program. Each member system should investigate the applicability of undervoltage load shedding beyond the standard contingency levels for Performance Levels A-D. The proper level beyond the standard contingency levels (i.e., Levels A-D) to be studied shall be determined by the member system. This load shedding program would serve as a “safety net” to prevent a system blackout.

## **2.6 Methodology for Measuring Reactive Power Reserve in Real-Time**

The RRWG makes the following recommendations for measuring reactive power reserve in real-time:

- The required margin specified in the planning arena should be available during operating periods. Expected extreme operating conditions must be extensively studied for simultaneous flow conditions. The operators must ensure that appropriate actions, such as reducing schedules over a critical path, dispatching additional generation, energizing capacitors, etc., are taken to ensure that the required margin is available.
- Member systems should consider the implementation of on-line software to monitor margin (refer to Section 11 for examples of such software) to assist their operators in monitoring reactive power reserves and assessment of voltage security.
- The required margin should be determined by off-line studies and nomograms should be provided, if required. Off-line studies can be conducted for various possible operating scenarios. Reactive power margins for each scenario can be determined and documented in look-up tables or nomograms. The parameters for nomograms could be interface flows, load levels, generator output, etc. The system should be operated under the limits defined by the look-up tables or nomograms.

- In the absence of on-line software or nomograms, system operators should monitor the available reactive power reserve at key locations in critical areas to ensure that adequate reserve exists. This reserve must be available from a combination of key on-line dynamic reactive power sources and automatically switched static reactive power sources. Dynamic reactive power sources include generators, synchronous condensers, static VAR controllers, etc. Static sources include capacitors or similar sources of reactive power.

Each source can be given a specific weighting factor to reflect its contribution to preventing voltage collapse in the study area. The total reactive power reserve of the area is the weighted summation of all sources in the area. The weighting factors should be determined by off-line studies. Based on off-line studies, contributions from each source for supplying the total required reactive power can be used to determine the weighting factors. Such weighting factors can also provide information on the most effective reactive devices to switch on line pre- or post-contingency conditions should the monitoring program find the reactive power reserve to be inadequate. Please refer to BPA's Computing Indices in Appendix C for an example of how these factors could be calculated.

## **2.7 Operator Training**

The Technical Operating Subcommittee (TOS) makes the following recommendations:

- Training materials be developed to educate the operators in reactive power issues, specifically terminology, basic concepts, and reliable system performance.
- Operators should be given clear instructions on how to maintain adequate reactive power reserves and corrective strategies to restore inadequate reserves.

### 3. INTRODUCTION

In the aftermath of the July 2 and 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Interconnected electrical transmission system, a group of WSCC members performed comprehensive assessments culminating in two reports: the “WSCC Disturbance Report for the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996,” and “WSCC Disturbance Report for the Power System Outage that Occurred on the Western Interconnection on August 10, 1996.”

Recommendations from both disturbance reports identified several reliability issues requiring further investigation.

On November 8, 1996, the Technical Studies Subcommittee (TSS) formed the ad hoc Reactive Power Reserve Work Group (RRWG) to address the issues identified in the disturbance reports. Two reliability issues were assigned from these reports (Items Nos. 10g and 10m in the August 10 disturbance report and Item No. 12 in the July Report) to the RRWG. The first issue involves the evaluation of system reactive power capability and the second issue involves evaluating the need for undervoltage load shedding schemes. Both issues seek to minimize associated adverse impacts caused by cascading outages and aid in quickly restoring the system to normal operation.

The assignments of the RRWG are summarized as follows:

- Develop a methodology for performing reactive power studies;
- Develop reactive power reserve requirements based on technical considerations;
- Develop a methodology for monitoring reactive power reserve in both the planning and operating arenas; and
- Determine if it is possible to design a “generic” undervoltage load shedding program.

## 4. WORK PLAN OVERVIEW

The RRWG prepared a work plan (“Work Plan”) which is included as Appendix A. The Work Plan restated the assignment, divided the work among regional areas, identified tasks, and outlined the general methodology for accomplishing the objectives.

The RRWG utilized information from various sources to complete the above-stated objectives. Sources included technical papers, publications, surveys (see Appendix B for RRWG Survey Results), BPA Blue Ribbon Panel, Operating Capability Study Group (OCSG), feedback from experts from WSCC member systems, and WSCC, NERC, CIGRÉ, and IEEE guidelines/standards. The RRWG had numerous meetings, phone conversations, and other informational exchanges resulting in the final recommendations included in this report.

The following issues were considered in meeting the objectives:

- Is it realistic to develop a reactive power margin criteria? If the answer is yes, can this margin be applied to all member systems? If the answer is no, how should the margin be specified?
- What contingency criteria should be used for measuring the margin?
- What methodology/tools should be used for measuring the margin?
- How should the margin be measured in the planning arena?
- How should the margin be measured in real-time? Can it be the same as that of planning?
- Can a “generic” undervoltage load shedding program be applied to each member system?

The following considerations were made in meeting the RRWG objectives:

- These criteria for post-transient voltage stability cover the period after the transient oscillations have damped out to before the operator can take manual actions and before area interchange schedules can be adjusted. This is beyond the transient time period; therefore, transformer load tap changers (LTCs) would have time to adjust.

- These initial criteria must be revisited as new methodologies and solutions are developed.
- If every member system adheres to these criteria, the entire Region will have a minimum reactive power margin.
- Some member systems may require more reactive power margin than the proposed Regional Reliability Criteria.
- The methodology must be easy to apply, yet comprehensive.
- Some modeling details must be left to member systems.
- The methodology must have sufficient flexibility for application to all member systems.
- The voltage stability criteria may have to be updated.

Appendix A provides additional information about the RRWG's approach in meeting the objectives.

## 5. DISCUSSION

The RRWG considered the following sources of information and data in its search for both a planning and operating criteria for voltage stability:

- Existing literature
- Results of WSCC OCSG studies
- BPA Blue Ribbon Panel recommendations
- Experience of other member systems/utilities
- Advice from industry experts
- Guidelines/standards by NERC, WSCC, IEEE, and CIGRÉ

The RRWG puts forward its recommendations in the spirit of the WSCC Reliability Criteria as expressed in the fourth and fifth paragraphs of Section 2.0 - Philosophy of the Criteria:

“Each member of the Council, each Pool or other group of Council members may have criteria which may be more stringent than the criteria presented in this report. Such differences may be justified by the geography of the area, type of load being served, system configurations, weather consideration, or other reasons. It is not required that such individual system criteria conform to this Council Criteria for the evaluation of that system’s planned performance for simulated disturbances or operating conditions on its own system. However, such criteria that differ from the Council Criteria may not be imposed on other systems if the differing criteria are more stringent than the Council Criteria, and the differing criteria must be applied consistently for all systems if less stringent than the Council Criteria. If an individual system, whose present criteria are less stringent than the Council Criteria, revises its criteria to require a higher level of performance, and is able to comply with the revised criteria, other systems shall also comply with the revised criteria up to the level of performance specified in the WECC Criteria. Any such criteria revisions should be closely coordinated with affected members and a reasonable period should be allowed before requiring other systems to meet the revised criteria.

Within the framework of the Western Interconnection, two or more systems may form a group for convenience of planning and operation. Such groups may agree to apply criteria within the group, for internal disturbances, that differ from the Regional Criteria. This does not relieve any WECC member system of its responsibility to apply WECC Reliability Criteria for disturbances on its system and the resultant effects on other systems outside the group.”

The RRWG’s primary goal was to find a minimum criteria that would be applicable to all member systems, i.e., to determine a minimum standard which would apply to an individual member system’s internal criteria and limit impact to a member caused by another member. Currently, it is not required that each individual system internal criteria conform to the Regional Reliability Criteria for the evaluation of that system’s planned performance on its own system. However, there is an ongoing effort within the Council to change this requirement such that the Regional Criteria would also apply to each individual internal system. Also, due to the inherent nature of a voltage collapse phenomenon, a voltage collapse in an area could easily spread to the neighboring interconnected area. A shortage of reactive power in an area can load up nearby generators in a neighboring system. Therefore, the RRWG recommends that the proposed voltage stability criteria should apply to each individual system’s internal criteria as well as limit the impact to a member system caused by another member system.

The criteria includes the following provisions for application to internal systems:

- Controlled load shedding is allowed for Performance Level A contingencies in order to meet the margins specified in Table 1.
- The margins in Table 1 do not have to be met if (a) the local area is radial or is a local network and (b) the contingency under consideration does not cause voltage collapse of the system beyond the local area.

Figures 5.1 and 5.2 show examples of a radial transmission system and a radial network. Please note that the provisions apply to a bus within a radial transmission system as shown in Figure 5.1, regardless of the number of elements connecting that bus to the network.

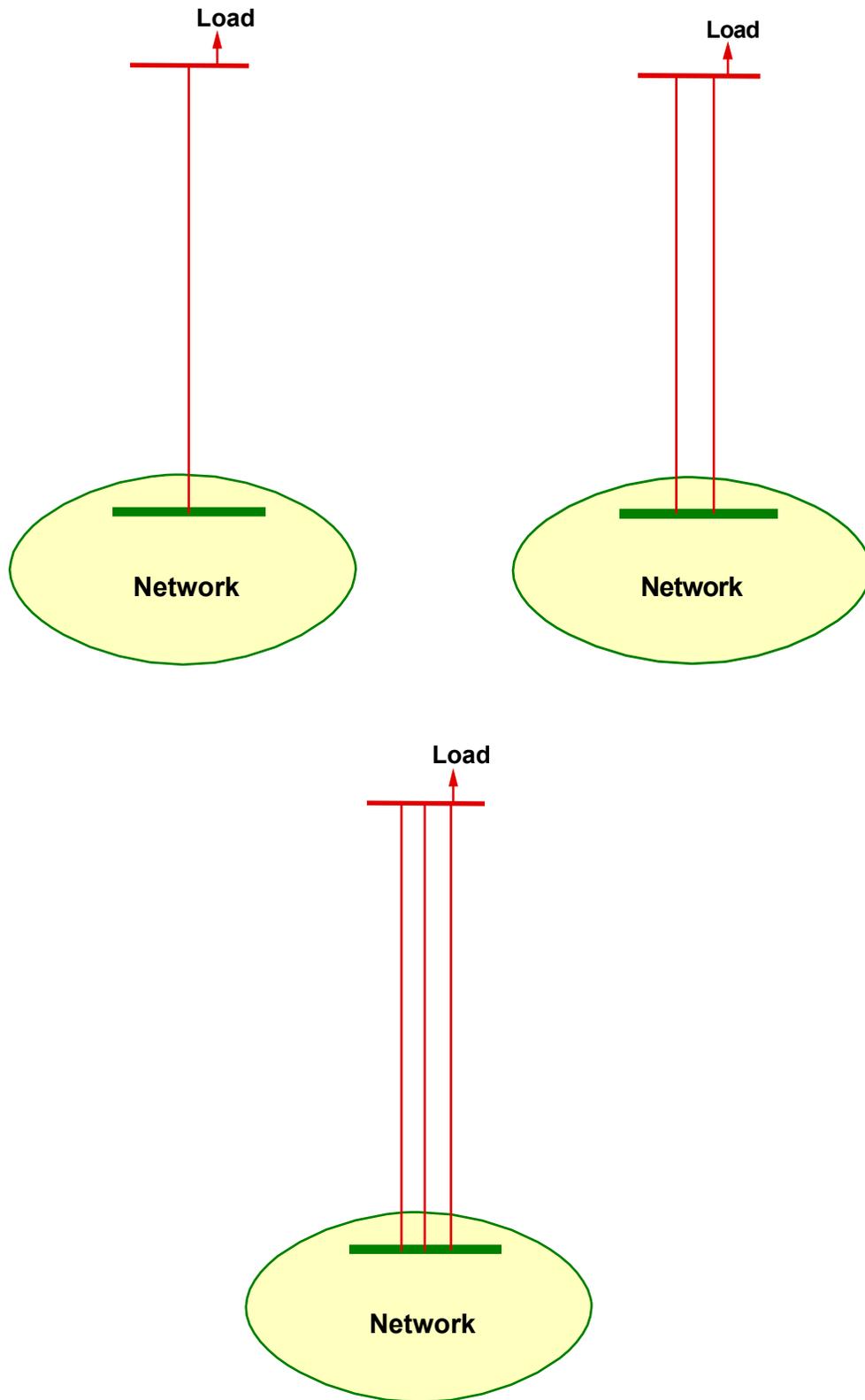


Figure 5.1 - Examples of Radial Buses

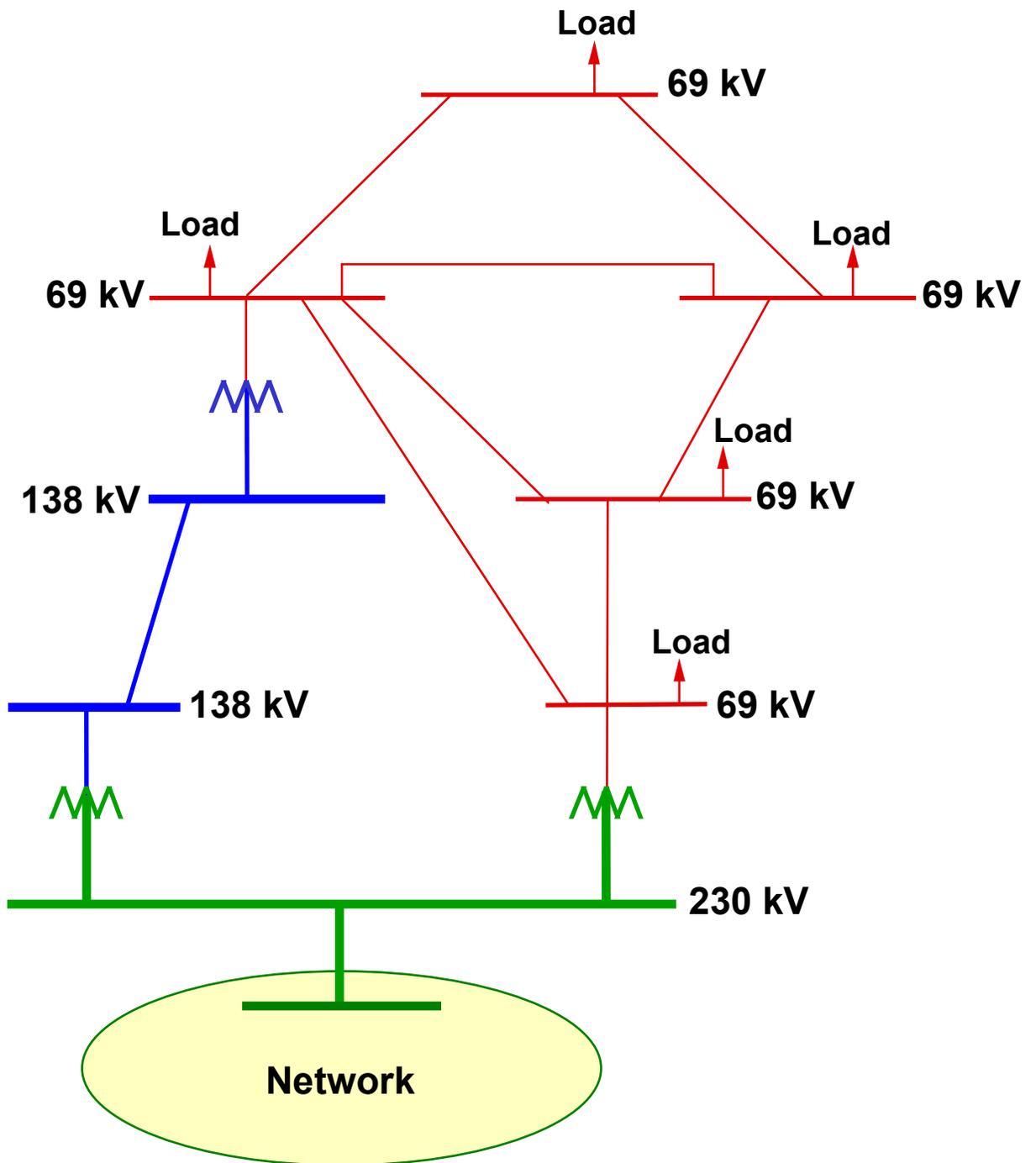


Figure 5.2 - Example of Radial Network

Both voltage stability of a load area and voltage support along intertie paths are areas of concern. Voltage stability along interties and the subsequent voltage depression may cause angular instability with voltage collapse at the electrical center. Power flow simulation does not determine stability, but it can determine maximum power transfer according to network laws and the models used. Stable operation is theoretically possible on the underside of a P–V curve.

The margin criteria for system contingency performance are based on results of simulation tests. The three main factors which have been considered in defining the criteria are as follows: (a) Performance Levels, (b) Disturbance Simulation, and (c) The Voltage Stability Criteria Table.

#### **(a) Performance levels**

Performance levels are defined by specifying the minimum required real or reactive power margin and are described below (a system element refers to a generator, transformer, line, reactive power source, etc.):

**Level A** This level represents the loss of any single element. Performance should not cause voltage collapse in the study area or outside the study area. The required real and reactive power margins must be provided. Consistent with the WECC Reliability Criteria, load shedding is not allowed for Performance Level A to meet the required minimum margin for contingencies in one member system affecting other member systems. However, for application of the criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system). Controlled load shedding refers to tripping of loads as the planned response to system events or system conditions. For example, undervoltage load shedding is considered an inherently controlled load shedding because the action is the planned response to specific conditions on the system at the load locations. The designed and automated tripping of interruptible load (e.g., synchronous motors) which occurs due to underfrequency, out-of-step conditions, loss of synchronism, or stator overcurrent conditions may also be considered as controlled load shedding. Unpredictable load drop, such as tripping of customer load due to overloading of its equipment or

random line tripping caused by protective relay action in response to a non-fault condition such as system swing is generally considered uncontrolled load shedding.

- Level B** This level represents the loss of any bus section. Performance should not cause voltage collapse in the study area or outside the study area. The required real and reactive power margins must be provided. Controlled load shedding may occur to maintain the required margin.
- Level C** This level represents the simultaneous loss of a combination of any two system elements in the study area without system adjustments. Performance Level C includes all common mode outages. Determination of credibility of all outages for this performance level is based on the existing WECC Reliability Criteria. Performance should not cause voltage collapse in the study area or outside the study area. The required real and reactive power margins must be provided. Controlled load shedding may occur to maintain the required margin.
- Level D** This level represents the simultaneous loss of a combination of any three or more system elements in the study area without system adjustments. Determination of credibility of all outages for this performance level is based on the existing WECC Reliability Criteria. Performance should not cause voltage collapse in the study area or outside the study area. The required real and reactive power margins must be provided. Controlled load shedding may occur to maintain the required margin.

**(b) Disturbance Simulation**

Study cases should represent worst case conditions such as maximum load and/or maximum interface flows in the study area. For P-V analysis, it may be necessary to start with a study case with less than maximum load levels and interface flows to be able to obtain sufficient points on the P-V curve before reaching the nose point of the curve (see Section 8).

Disturbances should be simulated at locations on the system that result in maximum stress on study area and on other systems.

### **(c) Voltage Stability Criteria Table**

The minimum level of margin which is acceptable under simulation tests is presented in the Voltage Stability Criteria Table (Table 1) considering the uncertainties outlined in Section 2.3. Table 1 is based on the planning philosophy that a higher level of performance is required for disturbances generally having a higher frequency of occurrence.

When multiple elements are specified, they are assumed to be lost simultaneously. Table 1 applies to the system with all elements in service and the system with one element removed and the system readjusted. In cases where a prior outage exists on a system, system adjustments will be made to allow the system to meet the required performance specified for the next disturbance. As an example, the loss of a generator with a prior system condition of one generator out should not be considered the simultaneous loss of two generators.

The voltage stability criteria and its application will be discussed in the following sections 5.1 and 5.2.

#### **5.1 Voltage Stability Criteria for the WECC System**

It is widely known that voltage magnitudes alone are poor indicators of voltage stability or security. Voltages can be near normal with generators, synchronous condensers, and SVCs near current limiting levels resulting in a possible voltage collapse [17]. Therefore, it would be prudent to specify a reactive power margin or MW margin criteria.

The RRWG concluded that the best approach for developing a margin is based on the existing Reliability Criteria Performance Table. The Performance Table specifies limits for voltage, frequency, and damping based on a deterministic criteria. Therefore, it would be appropriate to specify the margins based on a deterministic criteria and not a probabilistic criteria. The Council is currently in the process of evaluating a probabilistic based criteria. The RRWG members discussed setting limits for occurrence of a voltage collapse (e.g., limit the number of voltage collapse incidents in an area to one incident in 10 or 15 years). Since this specification requires a probabilistic approach, it was decided to defer setting this criteria until after the Council's Reliability Criteria has been modified. The recommended voltage stability criteria can be modified after the Council's Reliability Criteria has been based on a probabilistic approach.

In order to determine the required minimum margin, the following parameters were considered:

**(a) Load forecast or interface flow uncertainty**

The load forecast uncertainty provides a margin for conditions where the actual load increases higher than the forecasted load in a relatively short time. The increased load is immediately supplied by the available reserves or imports. A survey of literature indicated that a 5% load (with constant power factor) or interface flow increase would be a reasonable margin to use [14,22]. The United Kingdom and Japan are using a 5% load increase as their criteria for voltage stability which has been determined based on their experience and analysis. The 5% load increase would also cover conditions where additional system reinforcements are delayed due to budget or construction constraints.

If imports are increased, the interface flows are also increased. The 5% increase in interface flow above the maximum allowable limit would provide a margin for conditions where the actual flows are higher than scheduled because of loop flow or power flow drift during the scheduling hour due to system changes.

**(b) Modeling inaccuracies**

This parameter would account for system data representation inaccuracies such as line, generator, transformer, and other equipment data. The RRWG believes that modeling inaccuracies generally result in an implicit margin. Engineers should ensure that the most accurate models are utilized for system representations.

**(c) Other routine system outages**

This includes unavailability of other elements in the system that may have been removed due to forced or planned outages, relay misoperation, breaker failure, etc. The RRWG concluded that from a planning perspective the levels specified in Table 1 of this report contain sufficient levels of contingencies. Table 1 is applied equally to the system with one element removed and the system readjusted. This is consistent with the observation frequently made by system operators that the system is never completely intact. Therefore, routine outages which occur during real-time operation should be

monitored closely by operators and appropriate actions should be taken to maintain the required margin.

**(d) Differences between actual system operations and the conditions studied**

This parameter would account for system changes during real-time operation that may have not been studied. This includes generation dispatches, voltage schedules, etc.

Member system study results show that the margins specified in Table 1 for Performance Levels A-D would be appropriate as minimums for the region. Each member system must, however, examine the above parameters and the list of uncertainties in Section 2.3 to determine the required margin for its system.

## **5.2 Voltage Stability Criteria Application**

This Voltage Stability Criteria should be applied considering the specific configuration of each area, for example:

- A well-bounded, receiving region which is an isolated or semi-isolated area (including large metropolitan load centers and suburbs) wherein internal generation and load plus a few (one or two) tie lines clearly define the area of potential voltage collapse and reactive power reserve;
- Areas where major EHV (345 kV or 500 kV) lines by their interconnections affect the reactive power reserve and influence the quantification of reactive power reserve. These EHV lines may or may not belong to the owner of the load area, or lower voltage transmission system;
- “Transition” areas, if existent, from one to the other. (It may be fairly straightforward to recognize the transition from one type of area to the other. On the other hand, it may be difficult to clearly define such a transition. It is also important to recognize that ownership boundaries are not necessarily the transition from one area to the other.)
- The impact of severe contingencies involving loss of generation or load (e.g., the simultaneous loss of two units) on the weakest bus in the entire Western Interconnected system should be investigated.

The weakest bus may or may not necessarily be in the vicinity of the contingency. Therefore, buses in areas distant from the area where the contingency occurs should also be investigated.

## 6. POST-TRANSIENT STUDY METHODOLOGY

The System Review Work Group (SRWG) has recommended a methodology to perform post-transient power flow studies which has been approved by the Technical Studies Subcommittee (TSS). Please refer to Appendix D of the document titled, "Procedures for Regional Planning Project Review and Rating Transmission Facilities," for more information on the Council's Post-Transient Study Methodology. This report provides an update to this methodology.

The methodology recommended by SRWG for conducting post-transient studies is based on a governor power flow. This method assumes that all generators operating with unblocked governors will share the generation deficiency or surplus in proportion to their maximum generating capabilities until they reach their maximum or minimum output. The automatic actions of system elements in the 0-3 minute time frame after the disturbance are modeled to hold system voltage or frequency. Manual actions by operators are not modeled. The post-transient power flow procedure is discussed in the following paragraphs.

For each outage selected (Performance Level A, B, C, D), a post-transient case must be run to determine the critical disturbance and critical bus for that disturbance. This case must be developed using governor power flow procedures. The post-transient power flow studies and P-V and V-Q analyses can be conducted utilizing software such as EPRI's VSTAB, GE's EPCL routine, custom IPS COPE routine or custom PTI IPLAN routine. Sections 7 and 8 provide detailed information on the V-Q and P-V analyses, respectively.

The following step-by-step procedure is used to conduct the post-transient power flow simulation:

**NOTE:** It is assumed that the disturbance under investigation is transiently stable. Post-transient simulations should not be done when there is transient instability. Also, it is assumed that sufficient time after the disturbance has elapsed so that all elements of the system experience the same uniform frequency deviation. Finally, the period of time being simulated in the post-transient power flow run is after power and voltage transient oscillations have damped but before system operators have had time to make system adjustments including intertie schedules, etc.

1. Allow shunt capacitors and reactors which would complete automatic switching within 0-3 minutes to hold a set voltage at a bus. (The amount of reactance switched in each block, the set voltage and the name of the controlled bus would be needed). No manual operator intervention in switching either shunt capacitors or reactors can take place.

2. Phase-shifting transformer tap settings must be fixed at the pre-disturbance value, unless they would operate automatically in the 0-3 minute time frame.
3. Transmission voltage regulating transformers modeled in the pre-disturbance power flow to change taps in accordance with pre-set voltage schedules are fixed at their pre-disturbance level except where there is specific information to do otherwise. No manual operator intervention to reset transmission voltage regulating transformer taps is allowed.
4. Implement remedial action schemes (including generator and load or pump dropping) which in the 0-3 minute time frame would have automatically been activated for the disturbance in question.
5. All generators which manually control a high side remote bus must be set at the pre-disturbance voltage at the terminal bus or local bus. Only generators with automatic controls (i.e., no operator intervention), such as line drop compensation, are allowed to control a high side remote bus.
6. Whenever it is feasible, switchable capacitors should be modeled as capacitors, not as synchronous condensers. When capacitors/reactors are modeled as synchronous condensers, convert the condensers to fixed capacitors using their pre-disturbance MVAR value. These are mainly modeled in the Northwest area but all areas should be checked.

Following is a list of actual synchronous condensers/SVCs modeled in the Northwest:

- Keeler SVC
- Maple Valley SVC
- Coulee – up to 2 units
- Dalles – up to 6 units
- John Day – up to 4 units

Table 2 contains a general list of Northwest buses modeled as synchronous condensers; however, this list can change based on different cases. These buses should be held at their pre-disturbance shunt value in the post-transient simulations.

**Table 2**

**List of Northwest Buses Modeled as Synchronous Condensers**

ADDY 2	230	LONGVIEW	230	TACOMA	230
ALVEY	230	MAPLE VL	230	TAHKNICH	115
BANDON	115	MONROE	230	TILLAMOK	115
BELL BPA	230	MURRAY	115	TOLEDO	69.0
BENTON	115	NASELLE	115	TREGO	115
COL FALL	115	NO BROOK	115	TROUTDAL	230
COLV BPA	115	OLYMPIA	115	ALTURAS	69.0
CONKELLY	230	OLYMPIA	230	AMERICAN	69.0
COVINGTN	230	PORTANG	69.0	BOTHELL	115
ELLENSBG	115	REDMOND	69.0	CANAL	115
FAIRVIEW	115	RICHLAND	115	CRESTON	230
FAIRMONT	115	ROGUE	115	DELRIDGE	230
FOURLKS	115	ROSS	230	MASS	115
HARNEY	115	SANTIAM	230	NORTH	115
HARVALUM	230	SHELTON	115	SHORELIN	115
HEBO	115	SNOHOMSH	230	UNIVERSY	115
KITSAP	115	SNOHOMSH	115	VIEWLAND	115
LANE	230	SNOKING	230	SPKINDPK	115

7. Bypass those series capacitors that would do so automatically for the disturbance being studied.
8. Automatic actions of load shedding and generator tripping must be reflected in the transient and post-transient time period. For example, if a remedial action scheme drops load at a number of specified substations for the contingency under consideration, this load should be removed from these substations before the case is solved. Also, as another example, if an undervoltage load shedding scheme is available, the following steps should be followed during the post-transient simulation:
  - a) Solve the case for the contingency which is being considered

- b) Check voltages at the buses where undervoltage load shedding exists
  - c) If voltages are equal to or less than the undervoltage relay settings, remove the load which would be tripped by the relays from the base case
  - d) Resolve the base case with the load removed for the contingency under consideration
9. For disturbances where generation dropping and/or pump dropping is used as a remedial action, it is very important to consider how the imbalance between load and generation will be corrected. The methodology assumes that all generators operating with free governors will pick up their share of the generation deficiency (or reduce excess) in proportion to their capacities ( $P_{max}$ ) and inversely proportional to their governor droop setting until they reach maximum output. Whenever possible, generators which are electrically distant from the study area should be selected as the area swing generator and system swing generator. The following governors must be blocked in the studies:
- Diablo Canyon 1 & 2
  - Moss Landing 6 & 7
  - Geyser 5-20
  - San Onofre 2 & 3
  - Palo Verde 1, 2 & 3
  - Ashe 2

**NOTE:** Automatic Generation Control (AGC) will not significantly change generation within the 0-3 minute time frame. All governors of generating units in the system are assumed to have the same droop setting. All units initially loaded less than  $P_{max}$  capability will increase or decrease their output due to governor action in proportion to their capabilities (i.e.  $P_{max}$ ), unless a generator's governor is blocked.

10. Adjust, as necessary,  $Q_{max}$  for generators with a free governor in accordance with their reactive power capability curve (or other limitations that may limit the reactive power output) for the level of generation determined to be appropriate for the post-transient simulation (i.e., the post-transient  $P_{gen}$ ).

11. The overexcitation limiter protecting the generator from thermal overload is an important controller in system voltage stability. It is important to ensure that an appropriate value of  $Q_{\max}$  is used during post-transient periods for generators which are equipped with overexcitation limiters. Automatic control actions of overexcitation protection (e.g., tripping of generators due to exceeding their reactive power capability) should be modeled in the post-transient simulation.

## 7. V-Q ANALYSIS

V-Q analysis provides a way to investigate the potential for voltage collapse during the post-transient period within 3 minutes after a disturbance.

If there are insufficient or ineffective voltage control devices in an area to support high transmission path loadings during normal or contingency operation, voltages in that area could collapse resulting in a blackout. Besides having sufficient voltage control devices to sustain credible contingencies, it is prudent to have enough margin to account for variations in system conditions: (1) a major system component (e.g., a series capacitor segment) that is normally assumed to be on line may not be available; (2) the flow on the critical path could be higher than intended (metering inaccuracy); or (3) the system load could be higher than forecasted for that day (extremely hot or cold ambient temperature). The effects of these variations are considered in the determination of the required reactive power margin. The procedure for V-Q curve production, V-Q curve development, and determination of reactive power margin are described in the following sections 7.1, 7.2, 7.3, and 7.4.

### 7.1 Procedure for V-Q Curve Production

A procedure has been established for conducting a voltage collapse analysis based on V-Q curves. The procedure utilizes a normal load flow program. The V-Q curves are produced by running a series of load flow cases.

In order to produce the V-Q curves, the following procedure must be followed:

1. Set up a power flow case representing the system's post-disturbance condition as outlined in Section 6. Governor power flow must be used to establish this case representing an operating point (Normally, this case will be an N-1, N-1-1, etc., case with one or more elements removed from the system.). After the post-disturbance case is established, no adjustments (manual or automatic), are allowed during the development of the V-Q curve.
2. Identify the critical bus (also referred to as the weakest bus) in the system for this contingency. This is usually the most reactive deficient bus. The critical bus might change with the contingency.
3. Apply a fictitious synchronous condenser at the critical bus.

**NOTE:** If the power flow base case representing the system's post-disturbance condition as described in Step 1 does not solve, the

case may be deficient of reactive power. In order to analyze the case, the synchronous condenser should be added to the base case in Step 1 at the critical bus to solve the case for the contingency under consideration. The output of the synchronous condenser represents the amount of deficiency in reactive power.

4. Vary the condenser scheduled output voltage in small steps (usually 0.01 pu or less).
5. Solve the power flow case.
6. Record the bus voltage (V) and the reactive output of the condenser (Q).
7. Repeat steps 4 to 6 until sufficient points have been collected.
8. Plot the V-Q curve to determine if there is sufficient margin (see Figure 7.1).

The minimum point of this curve (where  $dQ/dV = 0$ ) is the critical point, i.e., all points of the curve to the left of the minima are assumed to be unstable. The points to the right of the minima are assumed to be stable.

If the minimum point of the V-Q curve is above the horizontal axis, the system is reactive power deficient. Additional infeed of reactive power is required to prevent a voltage collapse. A greater amount of reactive power is required in order to keep a VAR margin, as quantified by the distance between the horizontal axis and the critical point. Adequate margin must be provided to ensure system security and reliability is maintained.

If the critical point is below the horizontal axis, the system has some margin. The system may still be reactive deficient, depending on the desired margin, and maintaining acceptable post-transient voltages. Additional infeed of reactive power is required if a greater margin is desired.

Voltage instability or collapse is influenced by dynamic characteristics of loads and control equipment. Voltage collapse starts at the weakest bus and then spreads out to other weak buses. Therefore, the weakest bus is the most important in the voltage collapse analysis using V-Q curve techniques.

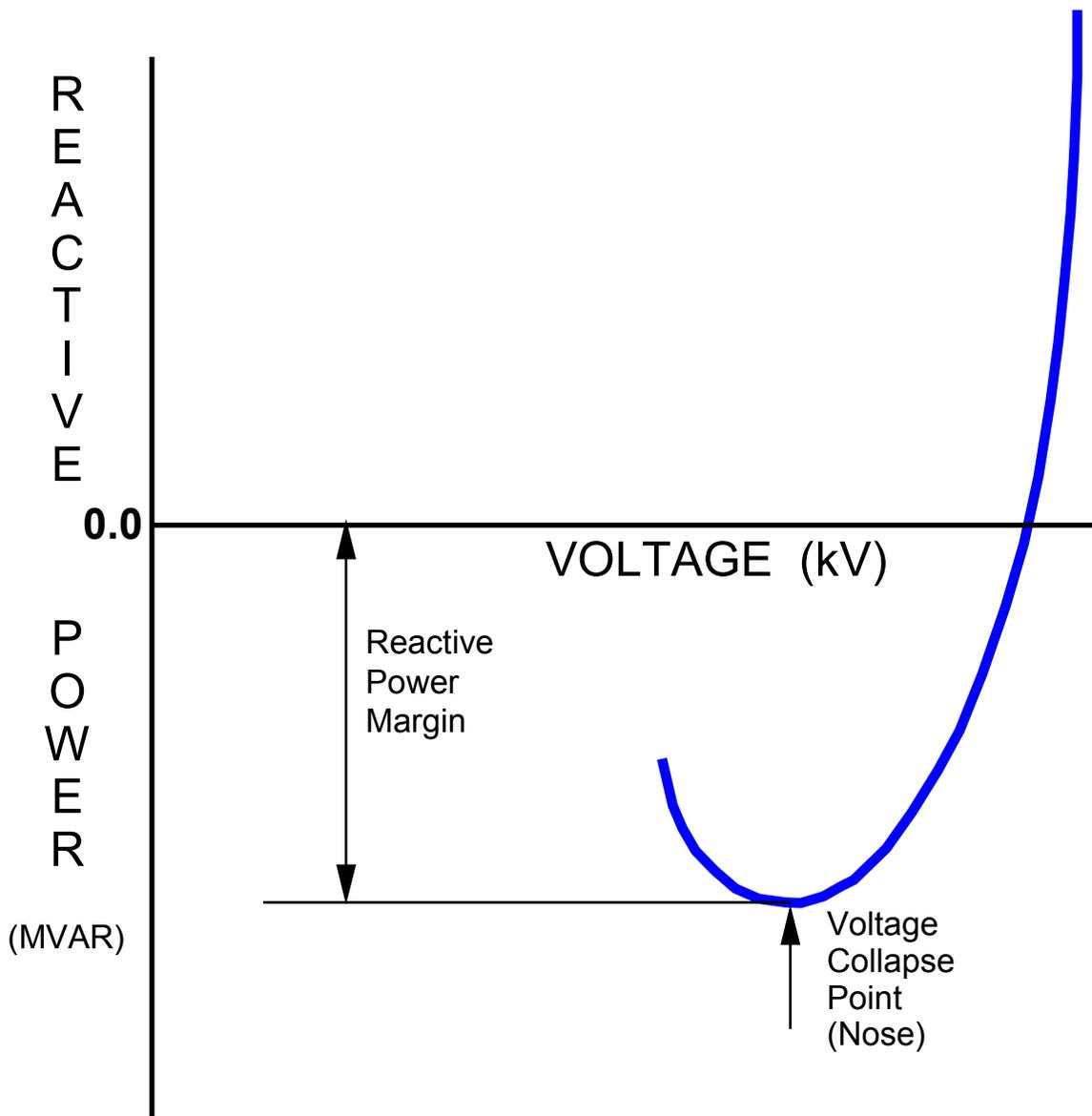


Figure 7.1 - V-Q Curve

The weakest bus is one that would exhibit one of the following conditions under the worst single or multiple contingency: (a) has the highest voltage collapse point on the V-Q curve, (b) has the lowest reactive power margin, (c) has the greatest reactive power deficiency, or (d) has the highest percentage change in voltage. A methodology to determine the “weakest” bus in a region is as follows:

1. Start with base cases that simulate reasonably adverse conditions for different seasons and load levels. (The load levels studied may, but not necessarily, be at the critical point on the P-V curve.)
2. Develop V-Q curves at a number of voltage sensitive buses using a post-transient governor power flow program on a number of single and multiple line outages to determine the most restrictive contingencies and the “weakest” bus in the study area.

Another method to determine the “weakest” bus is by monitoring the  $dV/dQ$  from the Jacobian matrix at buses throughout the system when the P-V curve is calculated (see Section 8 for further information on P-V methodology). The bus that has the largest rate of change of the  $dV/dQ$  before collapse (i.e., the “nose”) is the weakest bus.

Sections 7.2 and 7.3 describe two study methodologies: one for load area and one for interfaces.

## **7.2 V-Q Curve Development (Load Increase Methodology)**

The following methodology should be followed for studies involving load areas:

1. Start with an appropriate base case to represent worst case conditions for the load area of interest. Scale the loads to a 1 in 2 year occurrence load forecast and adjust resources appropriately. Load forecasts with a lower probability (e.g., 1 in 10 year occurrence, 1 in 20 year, etc.) could also be used.
2. Assume constant MVA loads unless more accurate load models are known. If load models other than constant MVA are used, the load voltage regulators/transformers in the distribution system must be modeled and active in the base case. The distribution system representation must be available to all WECC members for the resulting margin to be recognized. Accurate power factors for the loads should also be used.

3. Increase load by 5%. Ensure that loads are also scaled up in the neighboring systems if they have similar load characteristics. A constant power factor must be maintained when loads are increased.
4. Automatic and manual adjustments, which would occur within 30 minutes, are allowed for increasing the load. These adjustments include generation dispatch, tap changer and phase shifter adjustments, switching of devices, etc. A 30-minute time period for making adjustments is allowed since operators keep track of load increases over half-hour periods and can make system adjustments in a relatively short time (i.e., within 30 minutes) to bring the system to an acceptable operating condition.
5. Apply the post-transient procedures described in Section 6 for simulating the disturbance for each performance level.
6. Conduct V-Q studies for each of the worst contingencies identified for Performance Levels A-D to determine if the reactive power margin meets the required margin. The required margin includes the minimum margins shown in Table 1 considering the list of uncertainties in Section 2.3.
7. If the required margin is not met, determine if there are additional existing or planned facilities that are designed and expected to operate successfully during the post-transient time frame. Re-run the case adding these facilities to the post-transient procedure listed above to determine if the required margin is met. If the required margin is still not met, additional facilities or implementation of appropriate remedial action schemes would be required.

### **7.3 V-Q Curve Development (Interface Increase Methodology)**

The following methodology should be used for studies involving interfaces:

1. Start with an appropriate base case to represent worst case conditions for the interface of interest. The interface must be at its maximum rating and the worst load condition that the interface is rated for must be modeled.
2. Assume constant MVA loads unless more accurate load models are known. If load models other than constant MVA are used, the load voltage regulators/transformers in the distribution system must be modeled and active in the base case. The distribution system representation must be available to all WECC members for the resulting margin to be recognized. Accurate power factors for the loads should also be used.

3. Increase interface flow by 5%.
4. Automatic adjustments, which would occur within 0-3 minutes, are allowed for increasing the interface flow. These adjustments include tap changer and phase shifter adjustments, switching of facilities, etc. Automatic adjustments within 3 minutes are allowed since interface flows can change very quickly due to changes in operating conditions and, generally speaking, manual system adjustments are not made as frequently as for the case with load increases.
5. No manual adjustments are allowed for checking interface flow sensitivities.
6. Apply the post-transient procedures described in Section 6 for simulating the disturbance for each performance level.
7. Conduct V-Q studies to determine if the reactive power margin meets the required margin. The required margin includes the minimum margins shown in Table 1 considering the list of uncertainties described in Section 2.3.
8. If the required margin is not met, determine if there are additional existing or planned facilities that are designed and expected to operate successfully during the post-transient time frame. Re-run the case adding these facilities to the post-transient procedure listed above to determine if the required margin is met. If the required margin is still not met, additional facilities or implementation of appropriate remedial action schemes would be required.

#### **7.4 Determination of Reactive Power Margin**

For V-Q studies, minimum reactive power margin will be specific to the system and conditions under study. The minimum reactive power margin for Performance Level A shall be determined for each system by finding the maximum change in reactive power margin at the most critical bus in the study area as follows:

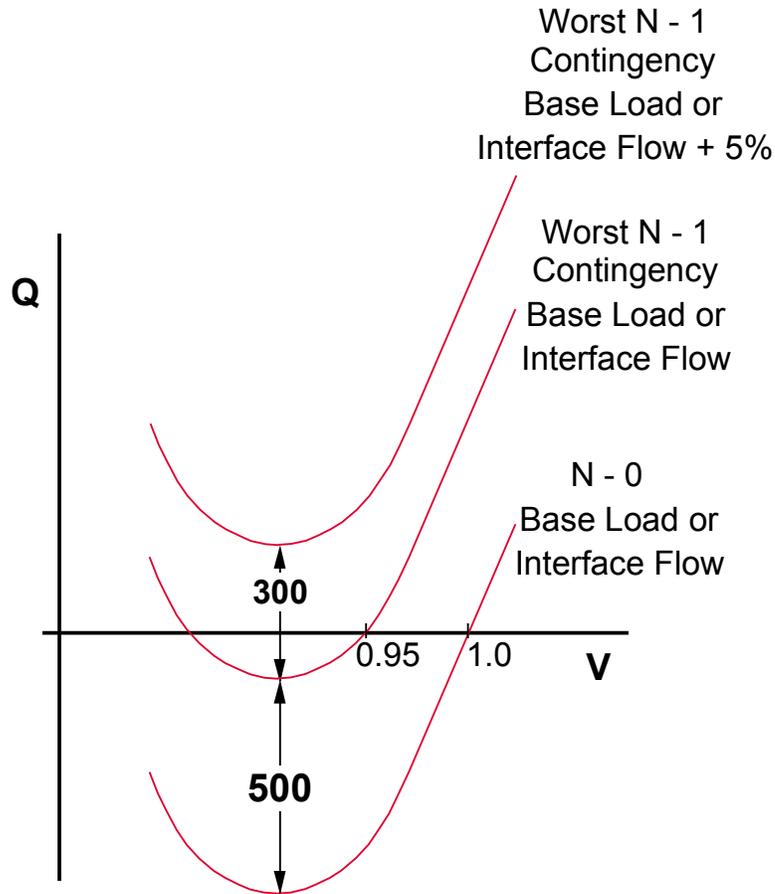
- (a) Determine the worst contingency for Level A for the area under study. This can be done by conducting numerous post-transient contingency studies involving large disturbances during worst-case conditions such as peak load and/or maximum import conditions.

- (b) Develop a V-Q curve for the worst single contingency identified (for Performance Level A).
- (c) Increase the area load or the flow on the critical interface by 5% and develop the corresponding V-Q curve for Performance Level A contingency.

The change in the margin is the amount of margin that must be provided for Performance Level A. An example is given in the following paragraphs.

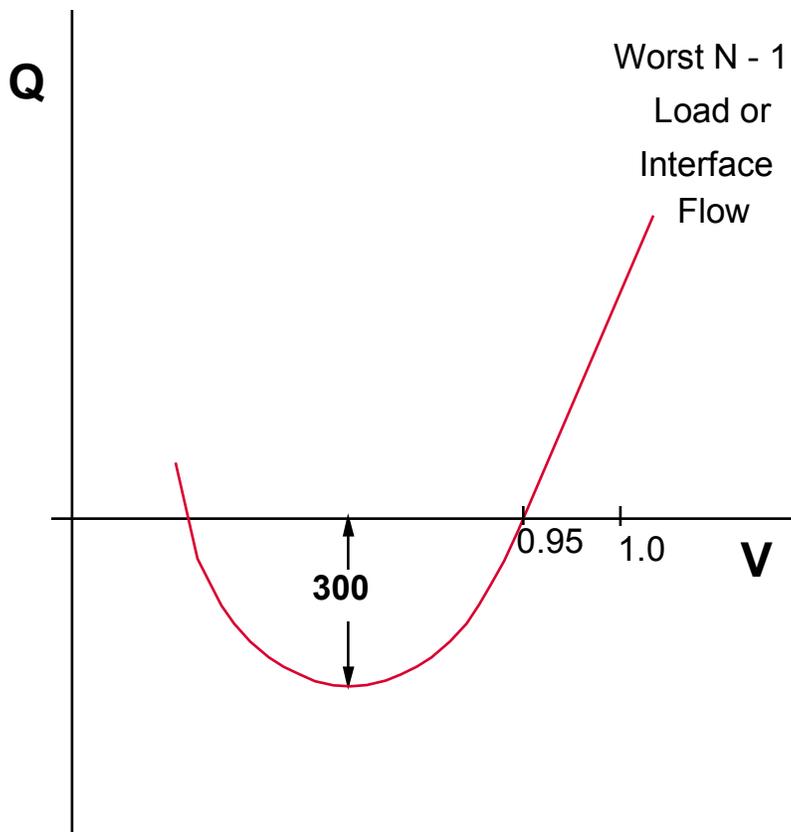
The first task is to determine how much margin is needed for V-Q analysis for the worst single contingency. Assume a system is in steady state worst-case conditions (e.g., peak loads and/or maximum interface flow levels) with all elements in-service at time  $t=0$ . Further assume that the worst single contingency and the most critical bus for this system have been already identified by conducting numerous contingency and V-Q analyses. The margin must cover the worst contingency for Performance Level A and a 5% increase in load or interface levels.

Consider the V-Q curve for the N-0 conditions as shown in Figure 7.2. Assume that the V-Q curve for the worst N-1 results in a reduction of margin by 500 MVAR. Furthermore, assume that the base load (i.e., both real and reactive power load) is increased by 5% and the V-Q curve is produced for the worst N-1 case. Suppose that this results in a further reduction of 300 MVAR in reactive power reserve as measured at the nose point and compared with the V-Q curve for the worst N-1 case with base load.



**Figure 7.2 - V-Q Curve Test for Determination of Reactive Power Margin**

Therefore, the total required margin is 300 MVAR for the worst single contingency without system adjustments. This implies that after a system experiences an N-1 contingency, at least 300 MVAR of margin must be available. The system is clearly deficient in reactive power and has a potential to collapse. After installing reactive power support, the V-Q curves must be reproduced to provide the necessary positive margin as shown in Figure 7.3. The margin covers the worst single contingency and a 5% load forecast or interface flow uncertainty. If capacitors are added to provide the required margin, an adequate amount must be added to take into account the relationship between the capacitor output and square of the voltage applied to the capacitors. For example, if the required margin of 300 MVAR is at a voltage collapse point of 0.9 pu, about 370 ( $300/0.9^2 = 370$ ) MVAR of capacitors would be needed to provide the margin.

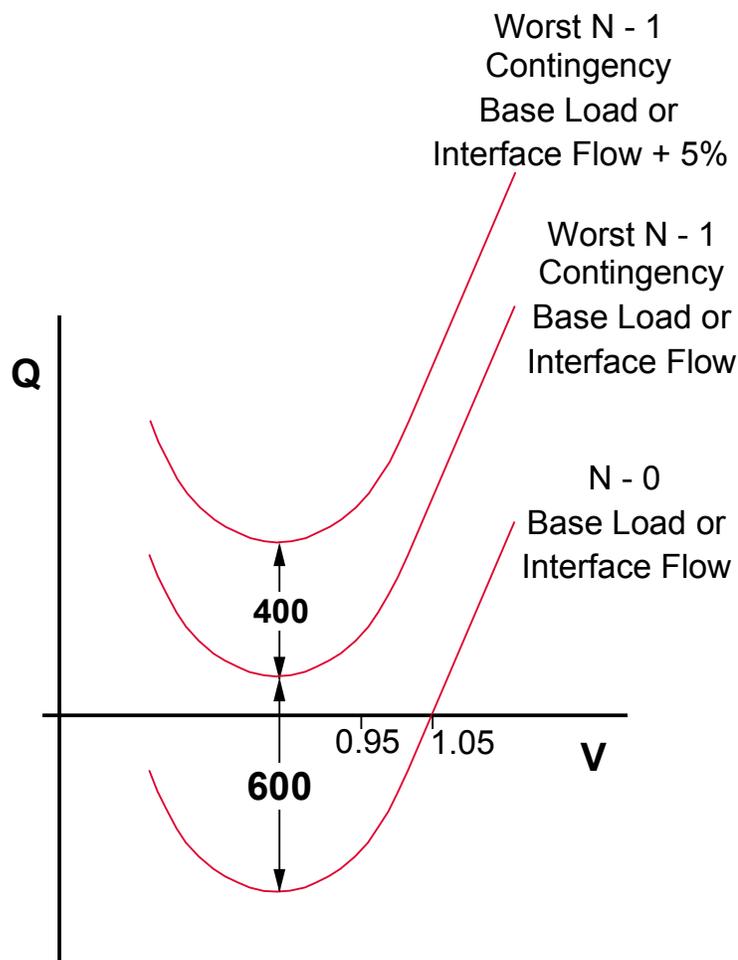


**Figure 7.3 - Required Reactive Power Margin**

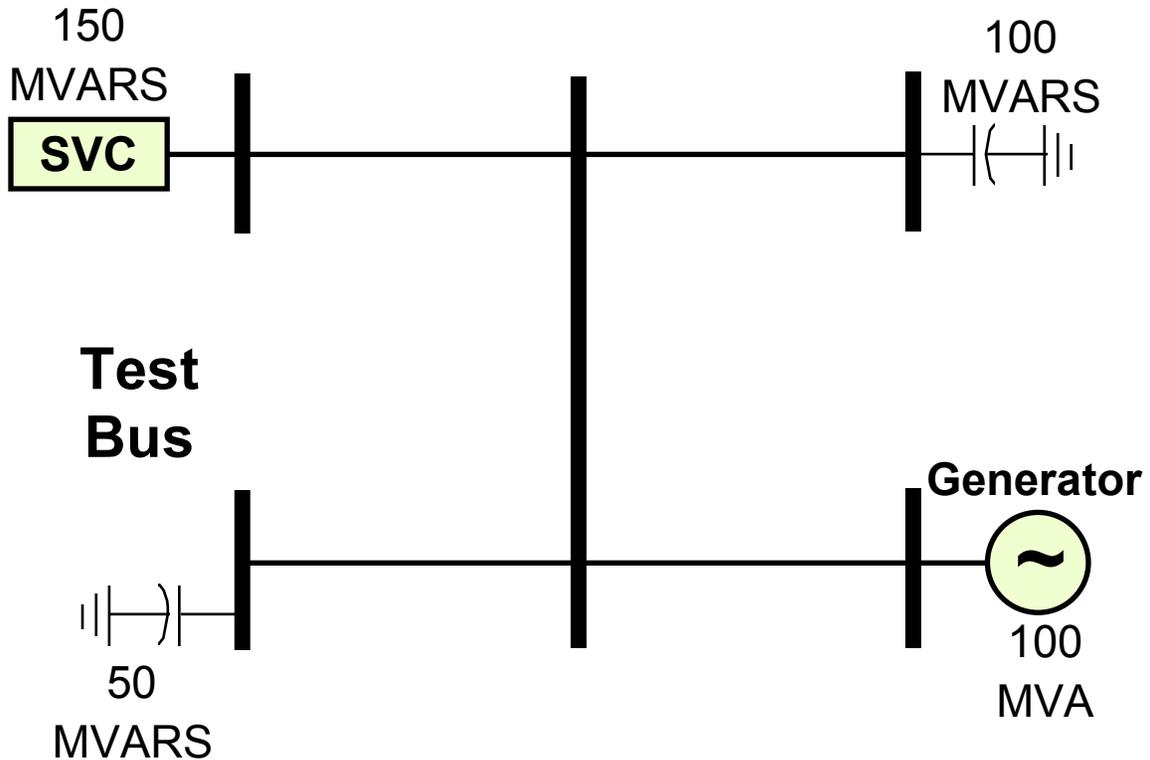
No tests are needed to determine the required MVAR margin for Performance Levels B through D. The amount of required margin for Performance Levels B through D is determined by multiplying the amount of margin determined for Performance Level A by the appropriate factor as shown in Table 1. For example, if the required reactive power reserve for Performance Level A is determined to be 300 MVAR, the required reactive power reserve for Performance Level B would be 50% of 300 MVAR, or 150 MVAR.

As indicated in Section 2.2, the criteria in Table 1 apply equally to the system with all elements in service as well as the system with one element removed and the system readjusted. An example will be given to illustrate this situation. Suppose a nearby generator is out of service for the example described above. Furthermore, suppose that the system adjustments required to displace the lost generation consist of dispatching a distant generator with no other changes to the system. The distant generator cannot provide reactive power support to the critical bus under study. Since the reactive power support from the generator which is out of

service is no longer available, the V-Q curves would have to be reproduced as shown in Figure 7.4. The N-0 curve in this figure represents the readjusted system which has a lower reactive power margin as compared with the system with all elements in service. Suppose this results in a reduction of margin by 600 MVAR as shown in Figure 7.4; the V-Q curves for N-1 contingencies also change as shown in Figure 7.4. In this case, the required margin is increased to 400 MVAR which has to be provided without the reactive power support from the generator which is out of service. In order to provide this margin in the absence of the nearby generator, other solutions such as reducing interface flows, adding reactive power support, etc., must be provided.



**Figure 7.4 - V-Q Curve Test for N-1-1 Conditions**



**Figure 7.5 - Example of a System for N-1-1 Margin Evaluation**

The technique described above can be applied if a nearby capacitor, transformer, SVC, etc., is out of service. For example, consider the system shown in Figure 7.5. Assume that the 50 MVAR shunt capacitor at the test bus is the most limiting element for reducing the margin at this bus for the worst single contingency. Furthermore, assume that the V-Q test for the worst N-1 contingency (with no prior element out of service) shows a margin requirement of 300 MVAR. Also, assume that no adjustments can be made to the system if this shunt capacitor is out of service. In order to satisfy the voltage stability criteria, the margin has to be increased to 350 MVAR (i.e., an increase of 50 MVAR to allow for prior outage of the capacitor).

## 8. P-V ANALYSIS

This section provides direction into completing a P-V analysis of a system. P-V analysis is a steady-state tool that develops a curve, which relates voltage at a bus (or buses) to load within an area or flow across an interface. Bus voltages are monitored throughout a range of increased load and real power flows into a region. The benefits of this methodology is that it provides an indication of proximity to voltage collapse throughout a range of load levels or interface path flows for the simulated system topology. Specific issues of modeling, study tools, and theory are the responsibility of the engineer and the study group with which he/she may be working.

The nature of voltage collapse is that as power transfers into a well-bounded region are increased, the voltage profile of that region will become lower and lower until a point of collapse is reached. The voltages at specific buses in the region can vary significantly, and some specific bus voltages could appear acceptable. The point-of-collapse at all buses in the study region, however, will occur at the same power import level, regardless of the specific bus voltages.

Begin a P-V analysis with an approved WECC power flow base case (i.e., with at least a 1 in 2 year occurrence load forecast) to ensure that the region external to the study area is represented in a reasonably accurate manner. An area susceptible to voltage collapse can be identified by a power flow contingency analysis. Cases that fail to converge to a solution or that exhibit large post-transient voltage deviations are typically in or near a voltage unstable operating point, respectively. If the power flow program has the feature that can monitor  $dV/dQ$  from the Jacobian matrix during the P-V run, these quantities can provide information on the buses where the collapse will begin. The bus that has the largest rate of change of the  $dV/dQ$  before collapse (i.e., the “nose”) is the weakest bus (see Section 7 for further information about locating the weakest bus).

Of the three types of load representation, constant MVA (a.k.a. constant power), constant current and constant impedance, constant MVA typically results in the most pessimistic point-of-collapse in a P-V analysis. A constant MVA load representation approximates the action of distribution system voltage regulating devices and, therefore, should be used unless more accurate load representations are known. If more accurate load representations are used, they should be modeled on the low side of load-serving transformers and the detailed modeling of voltage regulators on those transformers added to the system representation. Additional detailed representation of the lower voltage distribution system is also permitted. However, the system representation used to establish

voltage stability margins must be available to all WECC members for the resulting margins to be recognized.

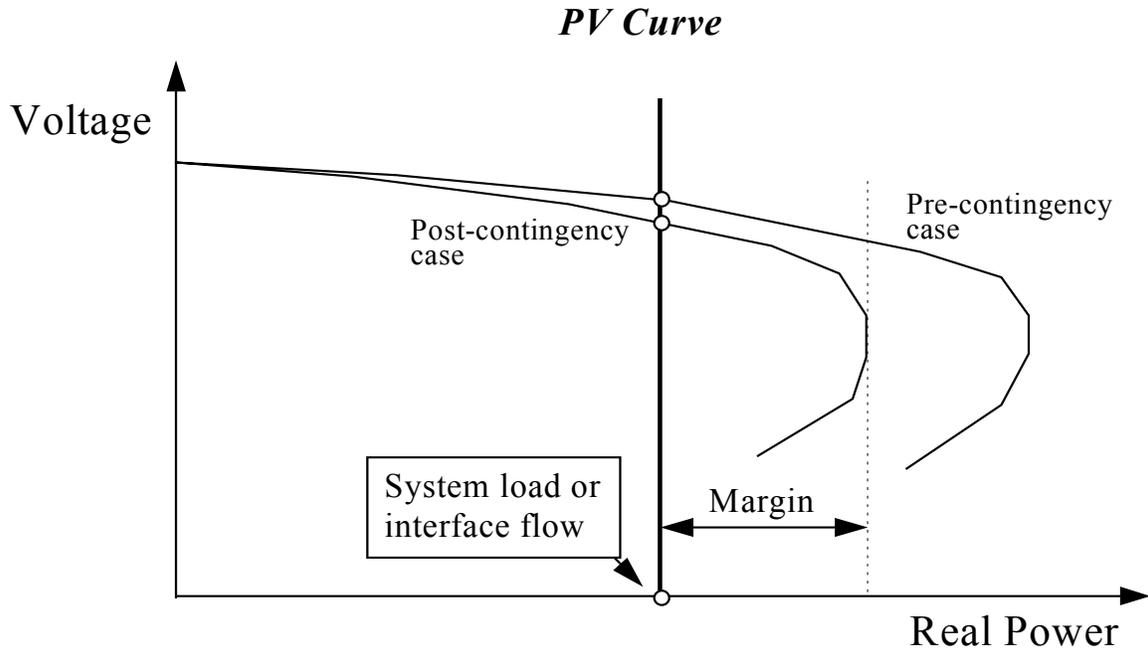
A full P-V curve (see Figure 8.1) can be produced by two methods. The first is by increasing the loads in the study region and increasing external generation. The second is by increasing flows across an interface (i.e., shifting generation from the receiving region to the external region). External areas that are resource constrained are permitted the use of a fictitious generator, solely for the purpose of establishing power margin. Good engineering judgment should be used in placing such a generator, and the generator should not supply reactive power. The following procedures cover these two methods of stressing a region to generate a complete P-V curve from low loads or low interface flows to high loads or high interface flows, respectively. Separate procedures are also provided and are to be used when the primary analysis method is V-Q and P-V checks are needed to ensure that the power margin is met.

The procedure for full P-V curve development, P-V tests, and determination of real power margin are discussed in the following sections 8.1, 8.2, 8.3, 8.4, and 8.5.

### **8.1 Full P-V Curve Development (Load Increase Methodology)**

The following methodology which should be followed for development of a full P-V curve for studies involving load areas is described below.

1. Choose a region as the study area wherein load will be incrementally increased. This could be a region that is suspected or known to be susceptible to voltage collapse and can be as large or as small as necessary. The quantities that will be varied are internal load, at a constant power factor, and external generation.
2. Model the loads in the study area initially at a level of approximately 20% of the expected peak load. This will provide the full benefit of P-V analysis, with the development of the P-V curve at levels below the operating points for which problems could be anticipated. Generation external to the study area should be reduced to match the scaled down load levels in the study area. As loads are scaled up in the study area, the effects of increased load requirements on the study region's voltage profile will be captured.



**Figure 8.1 - P-V Curve**

3. Set the internal study area generation to a constant level of the on-line units. The real power output of the internal generators should remain unchanged during the P-V analysis. The reactive power capability of each of the generating units should represent the unit's capability, and the reactive power output of each unit should be allowed to adjust as the P-V analysis progresses. Voltage collapse will occur in the study region after the VAR capability in the study region is depleted.
4. Choose the bus or buses in the study area at which the voltages will be monitored as the power transfers into the study area are increased. As an initial investigation of a region for voltage instability, the engineer should select several buses to monitor. The monitored voltages are the y-axis data of a P-V curve. See sections 7 and 8 regarding methods of identifying buses to monitor.
5. Determine (a) if the x-axis data will be load or interface flows, and (b) if the units will be MW or MVA (see Figure 8.1). If an interface path is used, it should be defined in a manner that measures all imports to the receiving region. A partial interface definition that allows imports into the receiving region over an unmonitored branch is incomplete. Choosing the x-axis to be study area load in MW is a good starting point.

6. Choose the system condition to be simulated. The system condition should be represented before internal loads and external generation are scaled up to develop the P-V data. A pre-contingency P-V analysis of the system provides an indication of the maximum capability of the study region to serve load. Simulating contingencies based on the performance levels of Table 1 are required to assure compliance with the voltage stability margins and provide information regarding the steady-state operating point that will occur after the contingency.
7. Solve the initial power flow case representing a low receiving area load for the performance level being studied using the post-transient methodology described in Section 6.
8. Record the bus voltages at the monitored buses, and the load level or interface transfer level at which the power flow case was solved.
9. Scale loads and external generation up to match the load increase. The load increases can be larger at lower load levels than at higher load levels, which are near the point of collapse. Ensure that loads are scaled up in the neighboring systems if they have similar climatic or geographic characteristics to the system under study. Initially, a load increase equal to the starting load level in the study region should be effective. If the power flow case fails to converge to a solution after a load increase, return to the last solved case, and scale up the loads by one-half or one-fourth of the previous attempt.

**NOTE:** When the load level reaches the starting load level, for the next 5% load increase, only automatic and manual adjustments, which would occur within 30 minutes, are allowed for increasing the load. These adjustments include generation dispatch, tap changer and phase shifter adjustments, switching of devices, etc.

10. The results of the P-V analysis could indicate that the voltage profile of a region is significantly lower than acceptable operating conditions at the point-of-collapse. In such cases, the limit of the system could be determined by other voltage criteria, such as post-transient voltage deviation or the lower limit of acceptable operating voltage. However, in some receiving regions, typically regions with a high degree of shunt compensation, the point-of-collapse will occur at or near bus voltages that appear acceptable. For these cases, the system should be designed with some operating margin from the point of collapse.

An example for the load increase methodology is provided. Suppose a chosen study area has an historical peak load of 100 MW with one 25 MW internal generator. The engineer is interested in determining the Level A load serving capability of the region. After performing a contingency analysis with a power flow program, the engineer knows the critical contingency and the buses that will be monitored in the study region.

The engineer starts with the WECC base case previously used in the power flow analysis, and scales loads in the study area to 20 MW at a constant power factor (It is assumed that the neighboring systems do not have a climatic or geographic characteristics similar to the study area.). Generation external to the study area is reduced by 80 MW. The internal generation is set at 25 MW with the appropriate VAR capability. The contingency is simulated and the power flow case is solved. At the 20 MW load level, the voltages at the monitored buses are recorded.

The loads in the study area and external generation are scaled up by 20 MW and the case is solved. At the 40 MW load level, the voltages at the monitored buses are recorded. The loads in the study area and external generation are then scaled up by another 20 MW, the case is solved, and the monitored bus voltages are recorded at the 60 MW load level. This process is also repeated for the 80 MW load level. However, at the 100 MW load level, the case fails to converge.

At this point, the engineer returns to the 80 MW case, and this time scales study area loads and external generation up by only 10 MW, the case is solved, and the monitored bus voltages are recorded at the 90 MW load level. This process is repeated for the 100 MW load level. However, at the 110 MW load level, the case fails to converge again.

The engineer returns to the 100 MW case, and this time scales study area loads and external generation up by only 5 MW, solves the case, and records the bus voltages. The process is repeated at the 110 MW load level, but this case also fails to converge. The engineer returns to the 105 MW case and scales up study area loads and external generation by 2.5 MW. This case is solved and the monitored bus voltage are recorded at the 107.5 MW load level. The loads and external generation are then scaled up another 2.5 MW and the case fails to converge. The engineer returns to the 107.5 MW load level and scales study area loads and external generation up by 1.25 MW, but this case also fails to converge. At this point the engineer decides that the point-of-collapse is determined to a reasonable accuracy, at 107.5 MW.

Based on this analysis, the engineer knows that Level A is met for the simulated contingency at historical peak loads, because the power margin is 7.5%.

However, with some load growth, this margin will not exist in the future. A 1% annual load growth will cause the margin to be inadequate within three years, and a 2.5% annual load growth will cause the margin to be inadequate within one year.

## **8.2 Full P-V Curve Development (Import Increase Methodology)**

The following methodology which should be followed for development of a full P-V curve for studies involving interfaces is described below.

1. Choose a receiving region as the study area wherein generation will be incrementally reduced. This should be an area on the receiving end of a constrained transmission path and can be as large or as small as necessary. The quantities that will be varied are internal generation and external generation.
2. The loads in the study area should be at highest possible levels and realistic power factors. The loads represented should be consistent with the projections for the season and year being evaluated for conformance with the performance levels in Table 1. As generation is shifted from the study area to the external area, the effects of increased power transfers across a monitored path on the study region's voltage profile will be captured.
3. Set the internal study area generation to a higher than normal level. The reactive power capability of each of the generating units should represent the unit's capability, and the reactive power output of each unit should be allowed to adjust as the P-V analysis progresses. Voltage collapse will occur in the study region after the VAR capability is depleted.
4. Choose the bus or buses in the study area at which the voltages will be monitored as the power transfers into the study area are increased. As an initial investigation of a region for voltage instability, the engineer should select several buses to monitor. The monitored voltages are the y-axis data of a P-V curve. See Sections 7 and 8 regarding methods of identifying buses to monitor.
5. The x-axis data will be interface flows, measured in either MW or MVA (see Figure 8.1). The interface path(s) should be defined in a manner that measures all imports to the receiving region. A partial interface definition that allows imports into the receiving region over an unmonitored branch is incomplete.

6. Choose the system condition to be simulated. The system condition should be represented before any generation shifts are made. A pre-contingency P-V analysis of the system provides an indication of the maximum capability of a system path. Simulating contingencies based on the performance levels of Table 1 are required to assure compliance with the voltage stability margins and provide information regarding the steady-state operating point that will occur after the contingency.
7. Solve the initial power flow case representing a low path flow (e.g., 20% of estimated maximum path rating) for the performance level being studied.
8. Record (a) the bus voltages at the monitored buses, and (b) the interface transfer level at which the power flow case was solved.
9. Shift generation from the study area to the external area. The generation shifts can be larger at lower path flows than at higher path flows, which are near the point of collapse. Initially, a generation shift of 10% of the study region generation should be effective. If the power flow case fails to converge to a solution after a generation shift, return to the last solved case, and reduce the shift by one-half or one-fourth of the previous attempt.

**NOTE:** When the interface flow reaches the starting interface flow level in the base case, for the next 5% flow increase, only automatic adjustments which would occur within 3 minutes, are allowed for increasing the interface. These adjustments include generation dispatch, tap changer and phase shifter adjustments, switching of devices, etc.

10. The results of the P-V analysis will often indicate that the voltage profile of a region will be significantly lower than acceptable operating conditions at the point-of-collapse. In such cases, the limit of the system could be determined by other voltage criteria, such as post-transient voltage deviation or the lower limit of acceptable operating voltage. However, in some receiving regions, typically regions with a high degree of shunt compensation, the point-of-collapse will occur at or near bus voltages that appear acceptable. For these cases, the system should be designed with some operating margin from the point of collapse.

An example for the import increase methodology is given. Assume a chosen study area is on the receiving end of a path capable of approximately 1000 MW. The engineer is interested in determining the Level A performance of the path. Previous analysis has been used to identify the critical contingency and the buses that will be monitored in the study region.

The engineer starts with the WECC base case previously used in the power flow analysis and starts with a path flow of approximately 200 MW. Generation external to the study area is scaled to accommodate the study area generation shift. The contingency is simulated and the power flow case is solved. At the 200 MW transfer path flow level, the voltages at the monitored buses are recorded.

The generation in the study area and external generation are shifted by 100 MW and the case is solved. At the 300 MW load level, the voltages at the monitored buses are recorded. This process is repeated for the 400, 500, 600, 700, and 800 MW transfer path flow level. However, at the 900 MW load level, the case fails to converge. At this point, the engineer returns to the 800 MW flow case, and this time shifts only 50 MW of generation, the case is solved, and the monitored bus voltages are recorded at the 850 MW transfer path flow level. This process is repeated for the 900 MW load level; however, the case fails to converge again.

The engineer returns to the 850 MW case, and this time 25 MW of generation is shifted, the case is solved, and the bus voltages recorded. The process is repeated at the 900 MW load level, but this case also fails to converge. Therefore, the engineer returns to the 875 MW case and scales up study area loads and external generation by 12.5 MW. This case is solved and the monitored bus voltage is recorded at the 887.5 MW flow level. Another 12.5 MW generation shift is made and the case fails to converge. The engineer returns to the 887.5 MW flow level and shifts 6.25 MW, but this case also fails to converge. At this point the engineer decides that the point-of-collapse is determined to a reasonable accuracy, at 887.5 MW.

Based on this analysis, the engineer knows that Level A is more constrained by voltage collapse than by the previous power flow and dynamic analyses.

### **8.3 P-V Tests (Load Increase Methodology)**

The WECC accepted methodology for conducting a P-V test for studies involving load areas is described below. The purpose of this test is not to develop a full P-V curve as described in Sections 8.1 and 8.2 but to ensure that the margins in Table 1 are met. The following methodology must be followed to test the real power margin.

1. Start with an appropriate base case to represent worst case conditions for the load area of interest. Scale the loads to a 1 in 2 year occurrence load forecast and adjust generation and imports accordingly. Load forecasts with

a lower probability (e.g., 1 in 10 year occurrence, 1 in 20 year, etc.) could also be used.

2. Identify the critical bus (also referred to as the weakest bus) in the system for this contingency (see Sections 7 and 8 for further information about locating the weakest bus).
3. Increase loads within a well defined load region in small steps (usually 1% of load per step). Ensure that loads are also scaled up in the neighboring systems if they have similar climatic or geographic characteristics. Increase generation from remote area(s) outside the study area which supply power to the load region to stress interface paths in the load serving area.
4. Assume constant MVA loads unless more accurate load models are known. If load models other than constant MVA are used, the load voltage regulators/transformers in the distribution system must be modeled and active in the base case. The distribution system representation must be available to all WECC members for the resulting margin to be recognized. Accurate power factors for the loads should also be used.
5. Automatic and manual adjustments, which would occur within 30 minutes, are allowed for increasing the load. These adjustments include generation dispatch, tap changer and phase shifter adjustments, switching of devices, etc. Individual curves should be generated for each automatic or manual adjustment. Individual curves are not needed for adjustment of automatic tap changers, or generator and synchronous reactive output with pre-set voltage set points.
6. Apply the contingency for the appropriate Performance Level using the post-transient methodology described in Section 6 and solve the power flow case.
7. Record the voltage for the critical bus identified.
8. Repeat steps 3 to 7 until the nose point has been reached or the case does not solve.
9. Plot the P-V curve to determine if there is sufficient margin.
10. The maximum operating points must have a margin equal to greater than the required margin for the performance level under consideration as measured from the nose point on the P-V curve. For example, the maximum operating point for Performance Level A is defined as the load level at the nose point multiplied by 0.95 (This represents a 5% margin for

Level A). The required margin includes the minimum margins shown in Table 1 considering the list of uncertainties described in Section 2.3.

11. If the required margin is not met, determine if there are additional existing or planned facilities that are designed and expected to operate successfully during the post-transient time frame. Re-run the case adding these facilities to determine if the required margin is met. If the required margin is still not met, additional facilities or implementation of appropriate remedial action schemes would be required.
12. Conduct P-V analysis for each of the worst outages identified for Performance Levels A through D (following steps 2-11 above).

#### **8.4 P-V Tests (Import Increase Methodology)**

The WECC accepted methodology for completing a P-V analysis for studies involving interfaces for a well-bounded area is described below. The purpose of this test is not to develop a full P-V curve as described in Sections 8.1 and 8.2 but to ensure that the margins in Table 1 are met. The following methodology must be followed to test the margin.

1. Start with an appropriate base case to represent worst case conditions for the interface of interest. The interface must be at its maximum rating and the worst load condition that the interface is rated for must be modeled.
2. Identify the critical bus.
3. Assume constant MVA loads unless more accurate load models are known. If load models other than constant MVA are used, the load voltage regulators/transformers in the distribution system must be modeled and active in the base case. The distribution system representation must be available to all WECC members for the resulting margin to be recognized. Accurate power factors for the loads should also be used.
4. Increase interface flow in small steps (usually 1% of interface rating per step). Facility ratings should be ignored to achieve the increase in interface flows. A list of facilities which are overloaded should be recorded, but no mitigative measures are required to resolve the overload problems.
5. Automatic adjustments which would occur within 3 minutes are allowed for increasing the interface. These adjustments include tap changer and phase shifter adjustments, switching of devices, etc. Individual curves should be generated for each automatic adjustment. Individual curves are not needed

for adjustment of automatic tap changers, or generator and synchronous reactive output with pre-set voltage set points.

6. Apply the contingency for the appropriate Performance Level using the post-transient methodology described in Section 6 and solve the power flow case.
7. Record the voltage for the critical bus identified.
8. Repeat steps 3 to 7 until the nose point has been reached or the case does not solve.
9. Plot the P-V curve to determine if there is sufficient margin.
10. The maximum operating points must have a margin equal to greater than the required margin for the performance level under consideration as measured from the nose point on the P-V Curve. For example, the maximum operating point for Performance Level A is defined as the interface flow at the nose point multiplied by 0.95 (This represents a 5% margin for Level A). The required margin includes the minimum margins shown in Table 1 considering the list of uncertainties described in Section 2.3.
11. If the required margin is not met, determine if there are additional existing or planned facilities that are designed and expected to operate successfully during the post-transient time frame. Re-run the case adding these facilities to determine if the required margin is met. If the required margin is still not met, additional facilities or implementation of appropriate remedial action schemes would be required.
12. Conduct P-V analysis for each of the worst outages identified for Performance Levels A through D (following steps 2-11 above).

## **8.5 Determination of Real Power Margin**

Minimum MW margin will be specific to the system and conditions under study. The minimum MW margin for Level A performance shall be determined for each system at the most critical bus in the study area as discussed below:

- Determine the worst contingency or contingencies for each Performance Levels A through D for the area under study. This can be done by conducting numerous contingency post-transient studies taking one element out of service at a time.

- Develop a P-V curve for the worst contingency or contingencies identified (for each Performance Level) by increasing loads and/or interface flows.

Similar to the V-Q methodology, tests should be done to determine the required amount of MW margin on a P-V curve. For example, consider the P-V curve for the N-0 conditions as shown in Figure 8.2. Assume that the P-V curve for the worst N-1 case results in a reduction of margin by 500 MW as measured from nose point of the P-V curve for the N-0 case to the nose point of the P-V curve for the N-1 case (distance between point 1 and point 2 as shown in Figure 8.2). Furthermore, assume that a 5% margin on the P-V curve for the worst N-1 case is considered to allow for load forecast uncertainty. The 5% is based on the load level measured at point 2. This results in limiting the load level or interface flow to a value shown as point 3 in Figure 8.2. Distance between point 2 and point 3 represents the 5% margin for the worst N-1 contingency.

Suppose that point 1 and point 2 represent a maximum load level or interface flow of 2000 MW and 1500 MW, respectively. This results in limiting the load level or interface flows to 1425 MW ( $0.95 * 1500 = 1425$  MW).

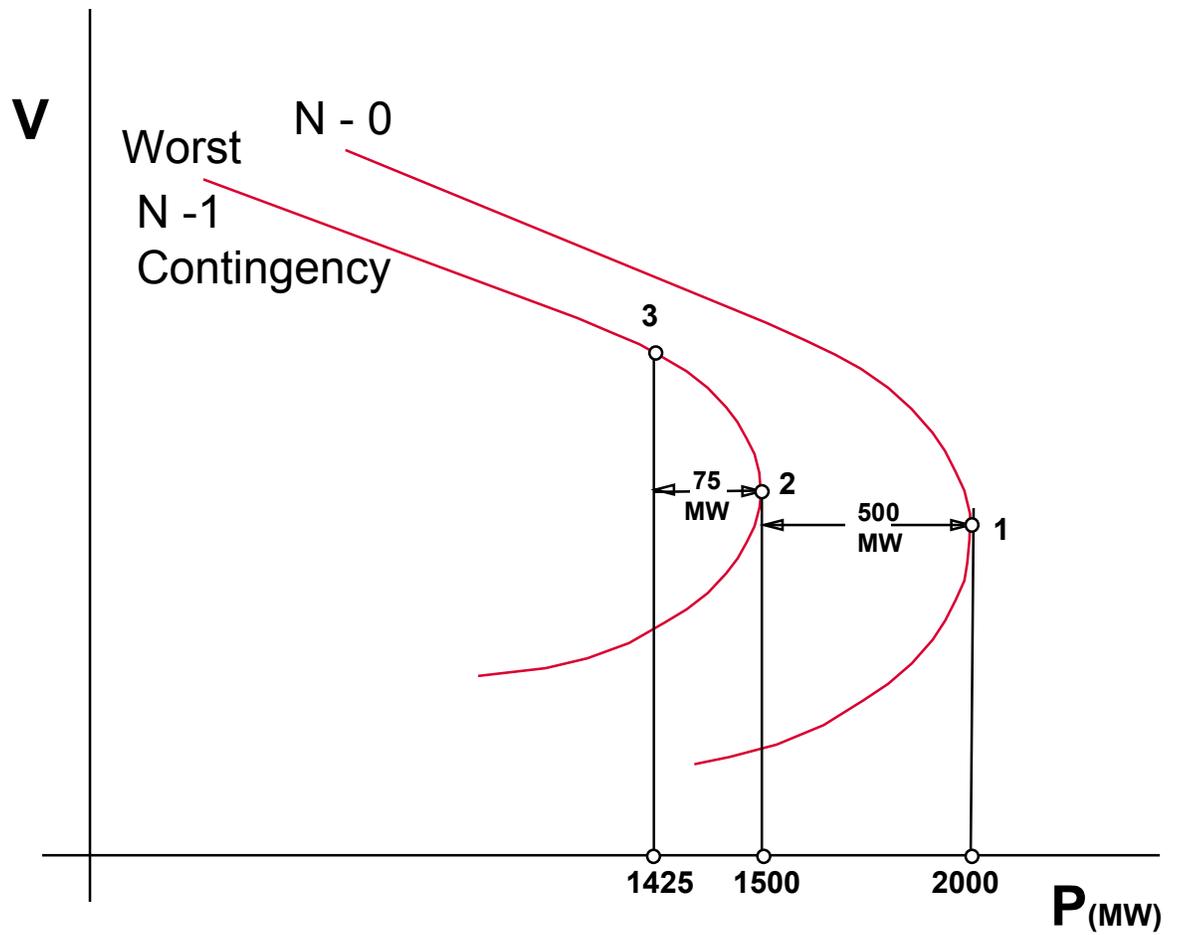


Figure 8.2 - Example of P-V Curves for Margin Evaluation

The critical interface flow must be limited to the value shown in Table 1 as measured at the nose point for each Performance Level as shown in Figure 8.3. Points 1, 2, 4, 6, and 8 represent the P-V nose point. Points 3, 5, 7, and 8 represent the maximum operating points.

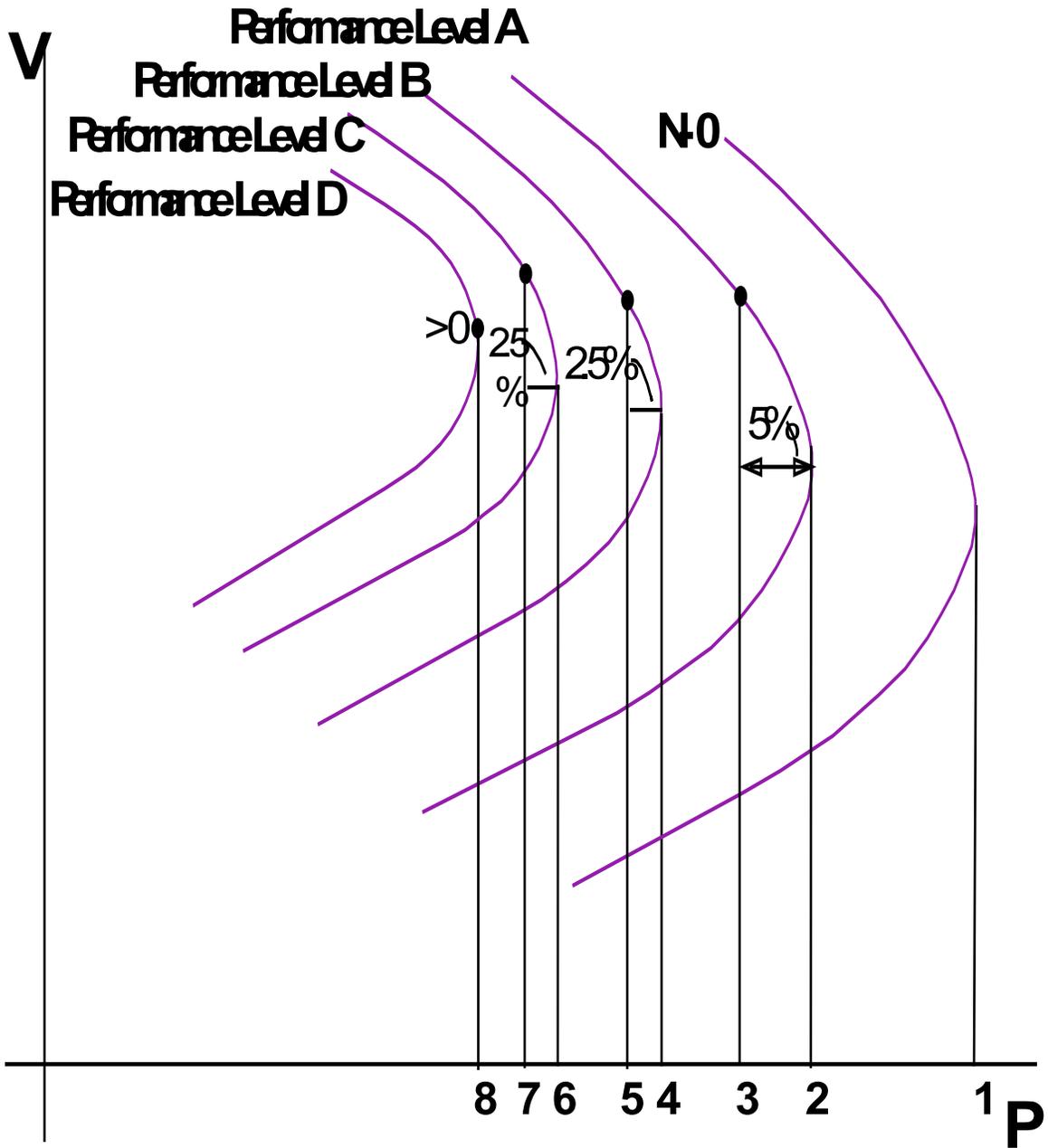


Figure 8.3 - P-V Curve Test for Determination of Real Power Margin

As shown in Figure 8.3, a 5% margin on the P-V curve for the worst case Level A disturbance case is required. The 5% is based on the load level or interface flow measured at the collapse point (i.e., point 2). The margin for N-0 conditions must be greater than 5%. Also, a 2.5% margin on the P-V curve for the worst case Level B and Level C disturbance cases is required. The 2.5% is based on the load level or interface flow measured at the collapse point (point 4 for Level B). The distance between point 4 and point 5 represents the 2.5% margin for the worst Level B contingency. Similarly, the distance between point 6 and point 7 represents the 2.5% margin for the worst Level C contingency. Finally, a greater than zero margin on the P-V curve for the worst case Level D disturbance case is required. The greater than zero is based on the load level or interface flow measured at point 8. Load levels or interface flows must be limited to the value at point 8 unless appropriate remedial action schemes such as undervoltage load shedding, direct load tripping, etc., have been implemented to cater for each Performance Level A-D contingency which restores the system to the allowable operating point (i.e., point 3, 5, 7, or 8) following the contingency.

If manual or automatic adjustments are normally made to increase the flows into a load area (within 30 minutes), or automatic adjustments are normally made to increase interface flows (within 3 minutes), additional curves should be generated for each system adjustment, as appropriate.

## 9. DYNAMIC VERSUS STATIC VAR SOURCES

The preceding sections of this report propose voltage stability criteria and methodologies to ensure that an adequate amount of reactive power would be available. If studies show that additional sources of reactive power would be needed to meet the criteria, a further study may be needed to determine the proper mixture of static (e.g., capacitors) and dynamic (e.g., SVCs, synchronous condensers, or generators) sources of reactive power.

Section I, Subsection D of approved NERC Planning Standards on Voltage Support and Reactive Power states that:

“Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Standards

**S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.”**

The purpose of this section is to recommend methodologies for determining the proper mixture of static and dynamic VAR sources to meet the required voltage stability criteria. Static devices such as mechanically switched capacitors are usually considered slow since it would require several seconds before they are energized. However, mechanically switched capacitors with high speed control could be an option if their effectiveness is verified by dynamic simulation studies. Dynamic sources such as SVCs, synchronous condensers, etc. can react very

fast, generally in a few cycles. Although SVCs are made of capacitors they are considered dynamic sources since their output can vary continuously at high speed.

## 9.1 Discussion

In order to further illustrate the need for determination of the proper mixture, an example is given. Suppose that voltage stability studies show that a system needs 400 MVAR of additional reactive power support. The reactive power deficiency can be solved by several options such as:

1. Build transmission lines
2. Install generation
3. Install SVCs
4. Install synchronous condensers
5. Install series capacitors
6. Install shunt capacitors

Load shedding is also an option for Performance Level A contingencies but only for internal systems. For the purpose of this example, it is assumed that load shedding is not considered. Therefore, option 6 would likely be the least expensive option. If any option(s) in 1-5 is selected, no further studies are needed for determination of the proper mixture. However, if it is decided to install automatically switched shunt capacitors, a further study may be needed to determine how much of the required 400 MVAR can be supplied by automatically switched shunt capacitors. The potential problems with installing 400 MVAR of capacitors are as follows:

1. It is possible that in some systems not all 400 MVAR of capacitors can be energized and remain energized during non-peak load conditions (i.e., with all elements in service) due to high voltage problems.
2. Automatically switched capacitors need to be switched on during contingency conditions, but they may be too slow and not in the right amount to prevent a voltage collapse.

3. To maintain voltage stability, an excessive number of capacitor switching events may occur which is undesirable and unacceptable and could lead to voltage collapse.
4. The timing requirement of capacitor switching actions may vary greatly depending on operating conditions. Slower switching actions may be needed due to normal interactions between changes in load, transformer load tap changers and generator reactive output variations. Fast switching actions may be required during transient conditions immediately after a contingency, which are too rapid for operator intervention, or several minutes after a contingency. Such wide ranges of timing requirements and coordination makes it difficult to rely solely on shunt capacitors.

If the proposed voltage stability criteria are met with no switched reactive power sources after the contingency during the most stressed conditions, no further studies are needed. Normally, this would entail demonstrating that margins are met with constant MVA loads. If the proposed criteria are met using switched reactive power sources and load models which provide relief for depressed voltages, further studies are needed to establish that the system will meet the criteria as voltages are restored to the load.

The recommended method is to conduct a long-term dynamic analysis examining the performance of the system. The simulation time depends on the system studied and could vary from a few minutes up to about 15 minutes following a contingency. Any dynamic simulation program, such as ETMSP, GE, or PTI, with capability to model long-term dynamics can be used for this purpose. The dynamic analysis can provide us with the information about exciter actions and how often capacitors are switched on or off and if they are successful in preventing a voltage collapse. The Council should pursue the development of a long-term, fast-time domain simulation option for the GE and PTI programs. The fast-time domain simulation option would significantly increase the speed of dynamic simulations. Long-term dynamic simulation is not, however, in widespread use at the present time. If long term dynamic simulation is not available, it would be practical to use a static (i.e., governor/post-transient power flow) analysis such as V-Q or P-V analysis to evaluate the impact of automatically switched capacitors. The static analysis would produce more conservative results than dynamic simulations.

CIGRÉ proposes a methodology using V-Q analysis to determine the required mixture of static and dynamic support. This methodology is explained by the following example.

Suppose a system is in steady state conditions with all elements in service. Consider the V-Q curve for the N-0 conditions as shown in Figure 9.1.

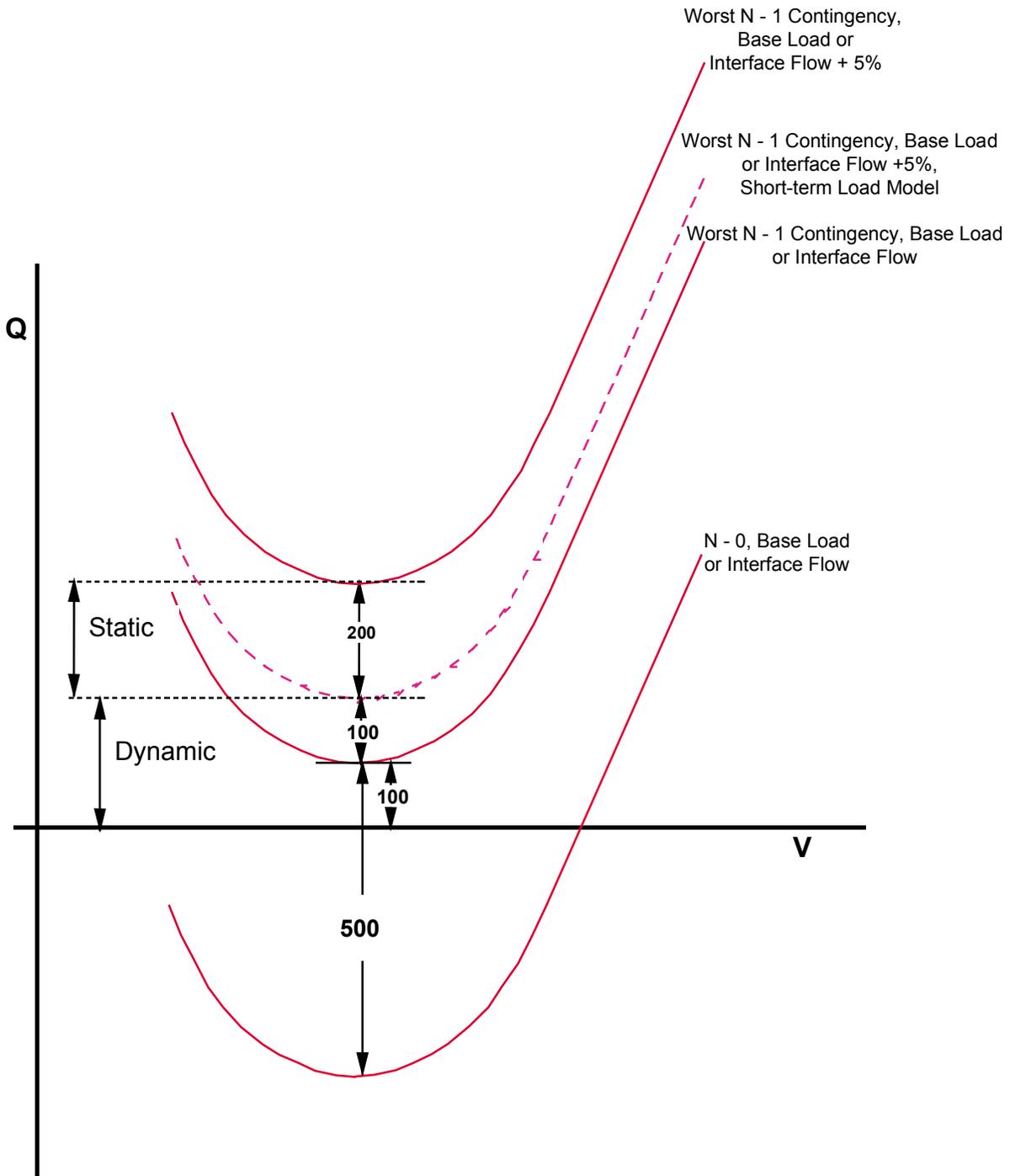


Figure 9.1- V-Q Curve Test for Determination of Mixture of Static and Dynamic Reactive Power Sources

Assume that the V-Q curve for the worst N-1 contingency results in a reduction of margin by 500 MVAR (see Figure 9.1). To determine the reactive power margin required, assume that the base load (i.e., both real and reactive power load) is increased by 5% and the V-Q curve is produced for the worst N-1 contingency case. Suppose that this results in a further reduction of 300 MVAR in reactive power reserve as measured at the nose point and compared with the V-Q curve for the worst N-1 contingency with base load.

Figure 9.1 shows that the system requires a margin of 300 MVAR. In order to provide the required margin, a total of 400 MVAR of reactive power must be added. To determine the mixture of static and dynamic reactive support needed, the Q-V curve analysis for the worst N-1 contingency and additional 5% of load is repeated by using a post-contingency, short-term load model rather than a long-term load model. The short-term load model may represent a lower load level due to reduced distribution voltages immediately after a contingency before slow control actions (e.g., transformer tap changers) have taken place. The post-transient procedures described in Section 6 for simulating the disturbance for each performance level should be followed except that all slow control actions (e.g., switching of capacitors, tap changer adjustments, etc.) should be turned off in the simulation. For example, the voltage at a particular distribution bus may be 1.0 pu before the contingency, 0.90 pu immediately after a contingency, and 0.95 pu after control actions have taken place. The load magnitude at this bus could vary as the voltage changes. The long-term load model would represent the full load after all control actions such as tap changers have taken place.

As described in this report each member system must develop load models for its system. A load model may look something like this:

$$P = P_0 (V/V_0)^a \quad Q = Q_0 (V/V_0)^b$$

Where,

- P = magnitude of real power
- $P_0$  = magnitude of real power at  $t=0$
- V = magnitude of voltage
- $V_0$  = magnitude of nominal voltage at  $t=0$
- Q = magnitude of reactive power
- $Q_0$  = magnitude of reactive power at  $t=0$

The parameters 'a' and 'b' depend on load characteristics and can be determined by load tests, using equipment data from manufacturers, etc. With 'a' or 'b' equal to 0, 1, or 2, the above load model represents constant power, constant current, or constant impedance characteristics, respectively. For composite loads, the value of parameters 'a' and 'b' depends on the aggregate characteristics of load components. A composite load model can be developed with individual terms for

constant power, constant current, and constant impedance loads. The composite load model would have the following form:

$$P = a P_0 V^2 + b P_0 V + c P_0$$
$$Q = d Q_0 V^2 + e Q_0 V + f Q_0$$

Where 'a', 'b', 'c', 'd', 'e', and 'f' are per unit multipliers for various types of load (i.e., constant power, constant current, and constant impedance).

After the load models have been developed, they can be used to estimate the values of P and Q by using the voltage magnitude immediately after a contingency. The short-term load model can be used in the power flow programs such as GE or PTI for the methodology described above to develop the V-Q curve immediately after a contingency. Automatic transformer tap changers must be locked at pre-contingency settings. This is important since tap changers would attempt to restore voltages to pre-contingency values which is not desired for this analysis.

The dashed V-Q curve shown in Figure 9.1 uses a short-term load model. Figure 9.1 shows that at least 200 MVAR of the reactive power support must be provided in dynamic form such as SVCs, synchronous condensers, etc. The remaining 200 MVAR can be provided by mechanically switched capacitors with automatic controls.

## 9.2 Recommendations

The RRWG recommends that:

1. The best method for determining the proper mixture of static and dynamic reactive power is to conduct dynamic simulations using the current GE or PTI programs. Member systems which already have the capability to conduct long-term dynamic simulations should use dynamic simulations to determine the required mixture of static and dynamic reactive power support.
2. If long-term dynamic simulation option is not available, the governor/post-transient power flow methodology outlined in this supplement should be used.
3. The Council should pursue the development of long-term, fast-time domain simulation option for the GE and PTI programs.

## 10. UNDERVOLTAGE LOAD SHEDDING

Electric systems experiencing severe disturbances and with heavy loading on transmission facilities can be vulnerable to voltage collapse. It is critical to the reliability of bulk electric systems that generators and transmission facilities remain interconnected during and after severe disturbances to expedite recovery efforts. A coordinated undervoltage load shedding program can be employed in preserving the security of a generation and transmission system in the event of system disturbances. Such a program is useful to minimize the risk of total system collapse, protect generating equipment and transmission facilities against damage, provide for equitable load shedding among load-serving entities, and improve overall system reliability.

Throughout this section and when studying voltage limited systems, undervoltage load shedding should be ranked among many options available to recover reactive power margin. Other options include shunt and series capacitor additions, automatic reactor and capacitor switching, MSC's, maximizing local generator reactive capacity, generator line drop compensation, and blocking or coordinating load-tap changing.

Since voltage collapse can occur suddenly, there may not be sufficient time for operator action to stabilize the system. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage system conditions may be an effective means of stabilizing the system and mitigate the effects of a voltage collapse. Undervoltage load shedding schemes should be coordinated with other system measures used to disconnect load, such as remedial action direct load tripping.

Automatic undervoltage load shedding can be used with large areas that have strong transmission systems as a guard against voltage collapse in the event that multiple contingencies and extreme conditions should occur. When applied to low probability, multiple contingency events, undervoltage load shedding provides a low-cost means of preventing widespread system collapse.

For example, in the Pacific Northwest, studies showed that if a double contingency outage of 500 kV lines occurred at the same time as a 1 in 20 occurrence winter peak load, voltage collapse could occur on loads and transmission in the Puget Sound area. While this may not warrant the immediate investment of additional 500 kV transmission lines, undervoltage load shedding relays have been deployed and are used throughout the Puget Sound Basin to automatically trip sufficient loads to arrest voltage collapse in the event that the multiple contingencies were to happen.

Automatic undervoltage load shedding can be used with small areas that have weaker transmission ties to prevent a small area voltage collapse in the event that one or more ties are lost from service during heavy load periods. Application could be in instances where transmission reinforcements are delayed or they are not deemed to be cost effective because the load is not large enough.

Undervoltage load shedding relays can be used to trip a sufficient amount of load so that the remaining weaker ties can still serve the remaining load without causing a voltage collapse. The transmission operator must determine how to best restore the load.

An example of small area undervoltage load shedding is where a new 230 kV line and 230-115 kV transformer was delayed because of permitting and right-of-way issues. Undervoltage relays were employed, with a transfer signal that indicated loss of the transmission element. If the transmission element was lost from service, and undervoltage was detected, loads at the far end of the system were automatically tripped, until a local combustion turbine could be started. This was used for two years, until the reinforcement could be placed in-service.

Undervoltage load shedding can be done automatically using undervoltage relays to trip circuit breakers or switches that serve loads. Parameters to be specified for the relay include time delays and voltage thresholds to trip. Parameter settings are determined by modeling the time and voltage sensitivity of load characteristics and control actions in the dynamic system. Important control actions to include are transformer load-tap changing, capacitor switching, and generator VAR. controls. The parameters can be determined by (i) using mid- or long-term dynamic simulation programs or (ii) modeling load response and control action steps in sequences of power flow simulations.

The RRWG examined implementation of a universal undervoltage load shedding scheme to automatically drop a percentage of load in several blocks with a “generic” time delay and voltage settings for each member system. Several documents [10,13,17,20] were reviewed for this purpose. All of these documents indicate that

- local characteristics are vital in the analysis of voltage stability and undervoltage load shedding;
- the undervoltage time delay and voltage settings must be coordinated locally with other local protection systems;
- the amount of required load shedding varies from one area to another and must be determined locally by conducting studies; and
- too much load shedding could result in generator instability.

Therefore, the RRWG preliminary investigation indicates that a universal undervoltage load shedding scheme may not be appropriate. Further investigations are necessary. Appendix E contains a description of existing or planned load shedding programs within the Sacramento area and service areas of Idaho Power Company, Puget Sound Energy, PG&E, EPE, and BC Hydro. Undervoltage load shedding guidelines and methodology will be discussed in the following sections.

## 10.1 Guidelines

- Automatic undervoltage load shedding must be coordinated with other controls, such as automatic reactor and capacitor switching, MSC's, generator excitation limiting, and generator line-drop compensation.
- For multiple related contingencies, it is necessary to provide enough undervoltage load shedding to restore voltage control following the worst second contingency at the highest load projection (including an estimated worst-case maximum load projection error). A long-term dynamic simulation should be run to verify angle stability and performance of undervoltage load shedding.
- The sensitivity of loads to voltage and time duration should be determined. A load synthesis program (such as the EPRI LOADSYN Program) can help to model the voltage sensitivity of loads by equating the percent of a customer class to a typical load characteristic. To determine time sensitivity of loads, tests of voltage, MW and MVAR, versus time, can be conducted. Load sensitivity to voltage step changes caused by opening lines and switching a reactor on can be measured. Examples of such load tests are provided by Carson Taylor in reference 13, Power System Voltage Stability.
- The nature of possible voltage collapse may render local undervoltage load shedding relays ineffective. For example, the collapse may occur across a system because of high transfers and wide power angles, rather than from high loads in the area of collapse. Undervoltage relay tripping could be too slow or may exacerbate transfer loading, resulting in higher reactive flows and lower voltage. Analysis may show that a collapse condition could be reached at voltages that are higher than the settings that could reasonably be applied to local substantiation or distribution undervoltage load shedding relays. Direct load tripping would become necessary.

- The speed of collapse can be determined by changing the system load model in the power flow from constant MVA to constant impedance to represent an immediate load response to voltage. If the voltage collapse is going to be fast, the V-Q calculation will result in similar reactive margin as with the constant MVA loads. This method would allow a utility that uses voltage control relayed capacitors and reactors to determine if settings are adequate (fast enough) to arrest the declining voltage. If margin with constant impedance load model is higher than the margin with constant MVA load model, further investigation in time, versus voltage scenario, should be done to ensure that capacitors will switch in time. When performing this type of comparison, it is important to ensure (a) the area control is off and (b) excess or deficient generation serving losses and or reduced load components (modeled by constant impedance in the power flow) are redistributed using governor power flow methods. Dynamic simulation is, however, the best method for determining the speed of collapse.
- PTI's planning criteria [29] states that:

“For multiple related contingencies:

Provide enough undervoltage load shedding to restore voltage control following the worst second contingency at the highest load projection (including an estimated worst-case maximum load projection error). Run long-term simulation to verify angle stability and performance of undervoltage load shedding.”

## **10.2 Methodologies**

Load models are recommended in papers by Carson Taylor, reference 25, and IEEE, reference 26. The models represent the voltage and time sensitivity of aggregate loads as represented at the distribution substation. Appendix G contains NERC Planning Standards on Undervoltage Load Shedding.

## **11. METHODOLOGY FOR MEASURING REACTIVE POWER RESERVE IN REAL-TIME**

The capability to use P-V, V-Q, or other methods in real-time operation does not currently exist. In the absence of any on-line software program, the only easy way for operators to measure margin, in real-time, at this time, is by measuring the available reactive power reserve from various sources. Reactive power reserves of generators, synchronous condensers, and SVCs are sensitive indicators of voltage stability. If the available reactive power reserve from a generator is diminished such that its field current limit is reached, the field current of nearby generators could also reach their limits resulting in voltage collapse.

The required amount of reactive power margin as determined by planning studies must be maintained in real-time operation. This margin must be available from a combination of key on-line and automatically switched off-line reactive power sources. The on-line dynamic power sources include generators, synchronous condensers, static VAR. controllers, etc. Off-line sources include automatically switched capacitors or other sources of reactive power. Each source could be given a specific weighting factor in terms of contributing to the required reactive power margin. The weighting factors should be determined by studies. Based on off-line studies, contribution from each generator for supplying the total required reactive power can be used to determine the weighting factors.

BPA, in collaboration with EPRI, has installed a software package to monitor reactive power reserves and assess voltage security at their Dittmer Control Center (See Appendix C). This package will assist the operator in assessing the real-time reactive power margin, using on-line measurement of dynamic reactive power sources from generating plants and SVCs. Effective reactive power reserves are determined using sensitivity factors from on-line state estimation. These tools will enable the operator to assess that previously computed reactive margins are maintained with due allowance for real-time operational conditions of voltage and power flows. As in all developmental projects, the operator should be cautioned in the use of such estimator tools until sufficient experience is achieved in measurement and estimating accuracy.

EPRI has a research project (On-line Voltage Security Assessment, Project 3040-3) for implementing and testing an on-line voltage security analysis using the available tools such as P-V and V-Q analysis. This could be used in the near future to more accurately measure margin during real-time operation and minimize the potential for voltage collapse (see Appendix D).

Several utilities monitor reactive power generation in real-time and switch reactive power devices, such as capacitors, to increase available dynamic reactive power reserves. Virginia Power [11], Florida Power, BC Hydro, and Swedish utilities [27] use reactive power reserves and voltage magnitudes for automatic load shedding and corrective measures to mitigate voltage collapse.

## 12. NERC REQUIREMENTS

Section B of Policy 2 - Transmission, Voltage and Reactive Control, of the NERC Operating Manual relating to reactive power requirements is stated as follows:

### "B. Voltage and Reactive Control

#### Requirements

1. **Monitoring and controlling voltage and MVAR flows.** Each CONTROL AREA shall ensure that formal policies and procedures and developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within its boundaries and with neighboring CONTROL AREAS.
2. **Providing reactive resources.** Each CONTROL AREA shall supply reactive resources within its boundaries to protect the voltage levels under contingency conditions. This includes the CONTROL AREA'S share of the reactive requirements of interconnecting transmission circuits.
  - 2.1 **Providing for reactive requirements.** Each PURCHASING-SELLING ENTITY shall arrange for (self-provide or purchase) reactive resources for its reactive requirements.
3. **Operating reactive resources.** Each CONTROL AREA shall operate their capacitive and inductive reactive resources to maintain system and INTERCONNECTION voltages within established limits.
  - 3.1 **Actions.** Reactive generation scheduling, transmission line and reactive resource switching, etc., and load shedding, if necessary, shall be implemented to maintain these voltage levels.
  - 3.2 **Reactive resources.** Each CONTROL AREA shall maintain reactive resources to support its voltage under first contingency conditions.
    - 3.2.1 **Location.** Reactive resources shall be dispersed and located electrically so that they can be applied effectively and quickly when contingencies occur.
    - 3.2.2 **Reactive restoration.** Prompt action shall be taken to restore reactive resources if they drop below acceptable levels.

- 3.3 **Field excitation for stability.** When a generator's voltage regulator is out of service field excitation shall be maintained at a level to maintain stable operation.
4. **Operator information.** The SYSTEM OPERATOR shall be provided information on all available generation and transmission reactive power resources, including the status of voltage regulators and power system stabilizers.
5. **Preventing Voltage Collapse.** The SYSTEM OPERATOR shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.
6. **Voltage and reactive devices.** Devices used to regulate transmission voltage and reactive flow shall be available for use by the SYSTEM OPERATOR.

## Guides

1. **Keeping lines in service.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels.
2. **Keeping voltage and reactive control devices in services.** Devices used to regulate transmission voltage and reactive flow, including automatic voltage regulators and power system stabilizers on generators and synchronous condensers, should be kept in service as much of the time as possible.
3. **Voltage and reactive devices.** Devices used to regulate transmission voltage and reactive power should be switchable without de-energizing other facilities.
4. **DC equipment.** Systems with dc transmission facilities should utilize reactive capabilities of converter terminal equipment for voltage control.
5. **Reactive capability testing.** Generating units and other dynamic reactive resources should be tested periodically to determine achievable reactive capability limits.”

Section C of Policy 6 - Operations Planning, Automatic Load Shedding, of the NERC Operating Manual relating to load shedding requirements is stated as follows:

### **“Criteria**

After taking all other remedial steps, a system or control area whose integrity is in jeopardy due to insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components of the interconnection (C.III.C.)

### **Requirements**

1. **Plans for automatic load shedding.** Each system shall establish plans for automatic load shedding (V.D.R.1.)
  - 1.1 **Coordination.** Load shedding plans shall be coordinated among the interconnected systems (V.D.R.1.1.)
  - 1.2 **Frequency or voltage level.** Automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level. (V.D.R.1.2.)
    - 1.2.1. **Load shedding steps.** Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels. (V.D.R.1.2.1)
    - 1.2.2. **Minimizing risk.** The load shed in each step shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. (V.D.R.1.2.2.)
    - 1.2.3. **Underfrequency load shedding on separation.** After a system or control area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, additional load shall be shed manually. (III.C.R.3.)
  - 1.3 **Coordination with generator, et al, tripping.** Automatic load shedding shall be coordinated throughout the Region with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions which will occur under abnormal frequency, voltage, or power flow conditions. (V.D.R.1.3.)”

Section I, Subsection D, Guide 7 of NERC Planning Standards, states that:

“Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.”

Appendix G contains a copy of NERC Planning Standards and Guides on ‘Voltage Support and Reactive Power’ and ‘Undervoltage Load Shedding’.

### 13. WSCC MORC REQUIREMENTS

Section II, Subsection B, and Section 4, Subsection A, of the WSCC Minimum Operating Reliability Criteria (MORC) document relating to voltage and reactive control is stated as follows:

- “1. **Maintaining service.** To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled, adequate reactive power reserves shall be provided, and adequate transmission system voltages shall be maintained.
2. **Providing reactive requirements.** Each entity shall provide for the supply of its reactive requirements, including appropriate reactive power reserves, and its share of the reactive requirements on interconnecting transmission circuits.
3. **Coordination.** Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment.
4. **Transmission Lines.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels.
5. **Generators.** Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g. constant power factor control) unless authorized to do so by the host control area. The control mode of generating units shall be accurately represented in operating studies.
6. **Automatic Voltage Control Equipment.** Automatic voltage control equipment on generating units, synchronous condensers, and static var compensators shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time.

7. **Power System Stabilizers.** Power System Stabilizers on generators and synchronous shall be kept in service as much of the time as possible.
8. **Reactive Reserves.** Generating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur.
9. **Switchable Devices.** Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.
10. **HVDC.** Entities with HVDC transmission facilities should use the reactive capabilities of converter terminal equipment for voltage control.”

Section 4, Subsection A, of the WSCC Minimum Operating Reliability Criteria (MORC) document relating to monitoring system conditions is stated as follows:

- “5. **Voltage Collapse.** Information regarding system problems that could lead to voltage collapse shall be disseminated and operation to alleviate the effects of such severe conditions shall be coordinated.”

**APPENDIX A**  
**DETAILED WORK PLAN**

**Team Members:**

- **Abbas Abed, (SDG&E)**
- **Joaquin Aguilar, (EPE)**
- **Nick Chopra (BCH)**
- **Robert Glickman, (PNM)**
- **Kevin Graves, (WAPA)**
- **Peter Krzykos, (APS)**
- **Andy Law, (WWP)**
- **Brian Lee, (BCH)**
- **Frank McElvain, (TSGT)**
- **Saif Mogri, (LADWP)**
- **Les Pereira, (NCPA)**
- **Craig Quist, (NPC)**
- **Joe Seabrook, (PSPL)**
- **Chifong Thomas, (PG&E)**
- **Boris Tumarin (EPE)**

**Chairman:**

**California Leader:**

**Desert Southwest Leader:**

**Northwest Leader:**

**Rocky Mountain Leader:**

**Abbas Abed**

**Abbas Abed**

**Robert Glickman**

**Brian Lee**

**Frank McElvain**

<b>CA</b>	<b>NW</b>	<b>Rky Mtn</b>	<b>DSW</b>
<b><u>Abbas</u></b>	<b><u>Brian</u></b>	<b><u>Frank</u></b>	<b><u>Robert</u></b>
<b>Chifong</b>	<b>Andy</b>	<b>Kevin</b>	<b>Craig</b>
<b>Saif</b>	<b>Joe</b>		<b>Joaquin</b>
<b>Les</b>			<b>Peter</b>

## **Main Objectives:**

The objectives of this group are to develop study methodology, develop reactive power reserve requirements based on technical considerations, and develop a methodology for measuring or monitoring reactive power reserve in both the planning and operating arenas.

Specifically answers to the following questions must be provided:

Is it realistic to develop a reactive power margin?

If the answer to the above question is yes, can this margin be applied to all member systems? If the answer is no then how should the margin be specified?

What contingency criteria should be used for measuring the margin?

What methodology/tools should be used for measuring margin?

How should the margin be measured in the planning arena?

How should the margin be measured in real-time? Can it be the same as that of planning?

Can a "generic" load shedding program be applied to each member system?

## Work Scope/Schedule:

1. Conduct research. Review the following books, documents, publications, etc., and prepare a summary as it relates to the main objectives by January 2, 1997:
  - (a) "Power System Voltage Stability", Book published by EPRI, Carson Taylor, 1994. (Frank, Kevin)
  - (b) "Voltage Instability Analysis", WSCC Publication, Voltage Instability Analysis Task Force, September 1989. (Robert, Craig, Peter)
  - (c) "Voltage Stability of Power Systems: Concepts, Analytical Tools, and Industry Experience", IEEE Publication, 90TH0358-2-PWR, 1990. (Brian, Andy, Joe)
  - (d) "Survey of the Voltage Collapse Phenomenon", NERC, August 1991. (Robert, Craig, Peter)
  - (e) "Modeling of Voltage Collapse Including Dynamic Phenomena", CIGRÉ Publication, March 1993. (Frank, Kevin)
  - (f) "Proceedings: EPRI/NERC Forum on Voltage Stability", EPRI Publication TR-102222, May 1993. (Abbas, Chifong, Les, Saif)
  - (g) "Power System Stability and Control", Book published by EPRI, Chapter 14, P. Kundur, 1994. (Brian, Andy, Joe)
  - (h) "Planning Against Voltage Collapse", Electra, No. 111, pp. 55-75. (Frank, Kevin)
2. Conduct a survey
  - Prepare questionnaire; send by December 6, 1996, receive by Jan 7, 1997. (Abbas, Chifong, Saif)
3. Research IEEE and IEE Transactions, etc., and prepare a summary as it relates to the objectives by January 3, 1997
4. Meet January 15 to discuss various issues
5. Review internal documents (to be done by each member system)

-Each member system should provide a summary of its methodology for determining margin. (All, to be completed by January 31, 1997)

6. Review "WSCC Voltage Stability Summary" document dated September 4, 1996 and prepare a summary. (All, to be completed by January 31, 1997)

-Find out what the member systems are using in terms of voltage collapse criteria (margin, contingency, methodology, modeling, etc.)

7. Review work done by "Reactive Study Review Group" of the Northwest and prepare a summary. (Brian, Andy, Joe to be completed by December 20, 1996)

8. Seek advice from experts within the Council:

- (a) Carson Taylor (to be contacted by Frank as required)

- (b) Wilsun Xu (to be contacted by Brian as required)

9. Determine the contingency level for determining margin and prepare a summary report (All, to be completed by February 28, 1997):

-Single, double, triple?

-Line, transformer, generator, SVC, etc

-Prior outages, maintenance

-How much risk to take?

-What level of reliability should we require? (Deterministic or Probabilistic Analysis?)

10. Determine requirements for setting a reactive reserve margin and prepare a summary report (All, to be completed by February 28, 1997):

-Establish definition of margin

-Amount

-Fixed or variable (system dependent?)

- MW or MVAR?
- How to measure?
- Mix of static and dynamic reactive power
- When to use load shedding?

11. Investigate what methodology to use for measuring margin and prepare a summary report (All, to be completed by February 28, 1997):

- Planning vs. real-time
- Feasibility
- Planning: V-Q, P-V
- Real-time: Generator VAR reserve, on-line load flow analysis, etc.

12. Determine what tools to use (All, prepare a summary report by February 28, 1997):

- Conventional Power Flow
- Governor (Post-transient) Power Flow
- OPF
- VSTAB
- Dynamic (ETMSP)

13. Investigate what modeling should be used for voltage collapse analysis and prepare a summary report (All, to be completed by February 28, 1997)

14. Find out what other member systems outside the Council are doing with respect to our objectives.

15. Compare requirements for setting voltage collapse criteria vs. transient stability criteria and prepare a summary report. (All, to be completed by February 28, 1997)

16. Meet in March to discuss work progress and findings (All)
17. Provide answers to the following questions (All, prepare a summary report by March 28, 1996):
  - Is it realistic to develop a reactive power margin?
  - If the answer to the above question is yes, then can this margin be applied to all member systems? If the answer is no then how should the margin be specified?
  - What contingency criteria should be used for measuring the margin?
  - What tools should be used for measuring margin?
  - How should the margin be measured in the planning arena?
  - How should the margin be measured in real-time? Can it be the same as that of planning?
18. Prepare a draft document summarizing the results of our investigation and recommendation and send for review. (All to be completed by April 15, 1996)
19. Finalize report. (All, to be completed by May 15, 1997)

## List of Papers:

1. "Application of an Optimization Method for Determining the Reactive Margin from Voltage Collapse in Reactive Power Planning", IEEE Trans. on Power Systems, C.J. Parker, I.F. Morrison, D. Sutanto  
  
(Frank, Kevin)
2. "Towards the Development of a Systematic Approach for Voltage Stability Assessment of Large-Scale Power Systems", IEEE Trans. on Power Systems, B. Gao, G.K. Morrison, P. Kundur  
  
(Brian, Andy, Joe)
3. "Methods for Determining Proximity to Voltage Collapse", IEEE Trans. on Power Systems, Vol. 6, NO. 1, February 1991 (Frank, Kevin)
4. "Steady State Voltage Instability, Operations Perspective", IEEE Trans. on Power Systems, Vol. 5, No. 4, November 1990  
  
(Frank, Kevin)
5. "Planning Methodologies for Voltage stability Limited Power Systems", W. Xu, Y. Mansour, P.G. Harrington, B.C. Hydro  
  
(Brian, Andy, Joe)
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The following methodologies to measure margin were investigated:

Planning:

Static:

V-Q (Governor power flow)

P-V (Governor power flow)

P-V and V-Q (Governor power flow)

Quasi-dynamic:

Modal Analysis (VSTAB)

Dynamic:

Long-term simulation (ETMSP)

Operating:

On-line generation VAR reserve

On-line software in conjunction with EMS

Off-line VAR reserve

Others

The following items were considered for specification of contingency levels:

- Deterministic specification
- Probabilistic specification
- Single contingency (N-1)
- Single contingency with a prior outage and system re-adjusted (N-1-1)
- Double contingency (N-2)
- Minimum contingency level (N-2, N-1-1, or N-1?)
- Credible multi-element contingency
- Definition of credibility

The following items were considered for determining the amount of margin:

- Fixed
- Variable
  - % of load
  - % of critical flow
  - condenser, capacitor, transmission line, etc.
  - Load forecast error
  - One of the above which has the greatest impact

- How to measure margin
  - From Nose point to V-axis
  - At a voltage level (e.g., 0.95 pu voltage)
- Dependence on Contingency Level:
  - Single contingency
  - Double contingency
  - Credible Multi-level Contingency

The following solutions to the voltage collapse problems were considered:

- First contingency:
  - VAR Support
  - Nomograms
  - Load Shedding
- Second contingency (or higher level credible contingency):
  - Remedial Action Schemes (RAS)
  - Operating Procedures (Nomograms)
  - Load shedding

The following items were considered for evaluating a “generic” load shedding scheme

- Feasibility
- Comparison with under-frequency load shedding
- Settings to use
  - Voltage level (0.85 pu)
  - timer (e.g.,, 8 seconds)
- Number of blocks (2,3,?)
- Amount of load shedding (3%, 5%?)
- Impact on angular stability
- Equity
- Studies needed to support any recommendations.
- Northwest Power Pool Plan
  - 1st step trip @ 90% in 3.5 seconds, drop 5% of load
  - 2nd step trip @ 92% in 5.0 seconds, drop 5% of load
  - 3rd step trip @ 92% in 8.0 seconds, drop 5% of load

**APPENDIX B**  
**SURVEY RESULTS**

- Survey sent to 35 member systems
  - A total of 14 responses received.
  - WSCC Summary refers to a WSCC report titled 'WSCC Voltage Stability Summary'.
1. Do you have planning/operating criteria related to voltage instability? If so, please describe them. (Possible methods of applying/operating margins include post-disturbance voltage profile, power margin on power transfers, voltage margin from critical voltage, critical voltage below a specified value, reactive power margin at bus, and reactive power reserve).

	RRWG Survey	WSCC Summary
V-Q analysis	6	13
Other	3	1
WSCC post-transient criteria	2	-
None	2	-
P-V analysis	1	2
Nomograms	-	1

2. What is your approach to applying a voltage instability criteria and what margin do you use? Why? (Please refer to Question 1 above)? Please give a short description of the methodology used by your company.

	RRWG Survey	WSCC Summary
500 MVAR	1	3
400 MVAR	1	1
250 MVAR	-	1
200 MVAR	1	-
35 MVAR	1	1
50 MVAR	2	1
None	5	4
4%	1	1
5-10%	-	1
5 MW	1	-
Load Shed	1	-
Other	-	1

## Contingency

N-1	3	4
N-2	4	4
Credible Multiple	2	-
None	5	9

## Voltage Criteria

None	7	8
WSCC post-transient	3	2
15 kV margin, 480 kV	1	-
2% dip	2	2
5% margin	1	2
10% dip	-	4

3. Some have advocated that a N-2 criterion be used for voltage instability. Do you agree? Why?

Yes : 4

Qualified Yes: 7

No Opinion: 2

No 1

- An N-2 criteria should be developed for voltage instability. N-2 criteria may be appropriate because N-2 outages are more severe and they do occur. Therefore, planning for an N-2 outage will ensure a safe and reliable operating region. The N-2 criteria if included must have a less stringent requirement than the N-1 criteria. The important thing to remember is that the N-2 outage must be a credible disturbance and must be the initiating event.
- A criterion of N-2 should be used. The criteria for a N-1 and N-2 may differ.
- Yes, the WSCC WATT criteria is N-2, the VAR criteria should be similar.
- N-2 is not a criteria for voltage instability in our area. Voltage instability can occur in our area for an N-1 condition. Voltage instability may also occur under N-0 conditions, for some systems, as load ramps and insufficient amount of reactive compensation is dispatched to follow the increased load.
- If the suggestion is to allow for a less stringent criteria for a less probable outage, this only seems appropriate as a corollary to the damping criteria. With voltage collapse eminent under single or multiple contingency, the amount of margin should be greater than zero and possibly equal to zero for the least probable contingency as is the damping criteria. The credibility of the contingency should be what governs the amount of margin.
- We agree only to the extent that the double-contingency scenario is probable. Also, the criteria for the N-2 conditions should be adjusted accordingly.

- I believe that the N-2 idea has some merit. The trouble with voltage collapse is that it is not simply that a voltage is below some arbitrary value, or that it deviated excessively, and perhaps caused some loss of load. Rather, it is a hard engineering point, which will cause loss of load to a larger, usually well-defined region. On the other hand, I believe that N-2 of two large transmission lines, or N-2 of two large generators is too excessive, and will be too expensive. I advocate that N-2 applies if used in combination, such as, unavailability of a VAR source, and the most critical transmission outage.
- No. It is beneficial to adopt a tougher reliability criteria but it should be system specific and performance based. Universal application of N-2 contingency may result in unnecessary reinforcements. Only N-1 and probable N-2 outages that are initiating events should be considered.
- We should consider all N-1 contingencies and credible N-2 contingencies that are the initiating events. This will be consistent with the existing WSCC Reliability Criteria. Also, the criteria for N-2 should be less restrictive than those for N-1 contingencies since N-2 are less probable than N-1.
- Partially agree. We agree for the common-mode N-2 outages, not for the independent events. Since the N-2 outages are area and disturbance dependent, the local criterion should be met. It is hard to have a generic cross-region N-2 criteria in WSCC system.
- We don't believe that N-2 is that bad of a criteria if you consider loss of a VAR source as one of the elements, i.e., loss of a VAR source and a line.
- Yes. It should be an additional study to N-1 though. The MVAR margin would be quite different between N-1 and N-2.

4. The probability of a N-2 disturbance may be similar to the transient stability criterion which involves a three-phase fault, with line outage (i.e., N-1), at a critical location. Do you agree? Why?

No Opinion: 5

Qualified Yes: 5

Yes : 2

No 2

- Maybe in the sense that the probability of a three phase fault is low and that it is a more severe disturbance compared to a single phase disturbance.
- It has been our experience that an N-2 event is a more probable cause of voltage instability.
- I suppose there are similarities, but the fact is that we have to define some principles to which we will design our system. Certainly, the probability of a three-phase fault is remote, but the issue is that we agreed to design our systems to that level. Even though the probability is low, I believe that the transient stability criterion is acceptable.
- This is one way to look at N-2 disturbances.
- No. The description refers to a three phase fault at a critical location that resulted in an N-1. If this is the case, assuming the same probability for an N-2 seem inconsistent with the existing WSCC Reliability Criteria.
- The latest blackouts shows that it happens.
- Yes, but the mixing of criteria with the probability of an outage does not make sense here. This answer addressed only the probabilities. The probability of a multiple contingency could be similar to that of a single contingency. Once the multiple contingency has occurred, the probability of another occurrence would increase.
- Before we start discussing probabilities of disturbances, we need to decide if the WSCC Reliability Criteria is a probabilistic evaluation or if it

is models significant outages as worst case as an umbrella for other outages.

5. How does your company deal with voltage instability for a N-2 contingency?

Not studied 3

Load shed 5

No action needed 6

6. Do you believe that a universal voltage instability criteria (e.g., reactive power reserve margin) could be applied to all systems? If so, please provide your comments on this subject.

Yes	2
Qualified yes:	5
No	6
No opinion	1

- Universal voltage instability criterion or process may be possible. A screening criterion may work. If an individual system met the screening criterion, a voltage instability problem does not exist. If it did not, further study would be needed.
- We believe that this may be difficult because voltage instability is very system dependent.

A qualified yes. Where systems are highly interconnected, and system reliability is interdependent, a minimum criterion is appropriate. However, voltage collapse is, generally, highly localized. The appropriate margin must be left to the utilities that will have to deal with the economics and reliability issues. Therefore, from a WSCC perspective, the minimum criterion must not be too burdensome.

- No. A process should be developed to determine specific criteria rather than applying a fixed criteria for all the systems.
- A universal voltage instability criteria in terms of reactive margin seems to be difficult since a particular level of margin in one location may be inappropriate for another location. Also, member systems model the load at different bus voltage levels, e.g., someone might be modeling their loads at 69 kV while another at 230 kV. The margin requirement cannot be the same for these two member systems. A criteria can be developed where all member systems must have a certain amount of dynamic reactive capability available (reserve requirement) at all times, maybe as a percentage of the MW or MVAR load. This reactive power can be supplied by generators, SVC's, etc.

7. Have you identified potential voltage instability problems in your system? If so, are they caused by other utility's systems or by outages on your own system? Both?

Yes	7
No	5
No answer	2

8. How would you characterize the voltage instability problems you might have identified? (e.g., fast/slow decay?)

Fast	2
Slow	5
N/A	7

9. Please provide suggestions for improved voltage instability analysis and study methodology.

None 2

V-Q 1

- I think that we need to proceed wisely into this endeavor. The trend is to define some VAR margin, when the important factor is to simply know that the amount of VARS on the system are adequate. The P-V method of analysis has much more meaning to a system operator.
- In addition to P-V/V-Q steady state analysis, long-term dynamic simulations of expected disturbances or contingencies would provide insight into the voltage collapse behavior of the given system.
- I believe this group should go ahead and collect information from everybody by way of studies etc. I would ask you to share this with the group. This will help others like ourselves at least be aware what is out there while we are trying to set up similar studies. We are especially interested in information re load shedding in relation to voltage instability situations.
- Improve generator and load voltage response modeling.
- Learn to use VSTAB.
- Develop real-time voltage stability indexes for operational monitoring.
- If WSCC is going to conduct post-transient studies on a regular basis and a criteria is developed for Council, it might be worthwhile for WSCC to investigate purchasing a long term dynamics program. I wonder if WSCC would want to create a Task Force with certain experts on the panel to address this particular issue or at least we should try and get input from them for our report, e.g., like Carson Taylor, John Undrill, etc.

## **APPENDIX C**

### **BPA's REACTIVE POWER RESERVE (MVAR) MONITOR**

## PURPOSE

There is a need to manage Voltage Security of the system based on the July 2 and August 10, 1996, system disturbances. Voltage Security assessment involves monitoring of the reserve available in dynamic system sources like generators and SVCs. The Reactive Power (MVAR) Monitor was developed to enable Dispatchers to continuously assess the system and to alarm when pre-determined limits are reached. A voltage security index is computed which weights projects according to their sensitivity to change and their size. The index is calculated so that it will be zero [0.0] if all plants are at or above their continuous reactive power limit. [Sort of like the gas gauge on a car]. The weighting is so a large plant close to the voltage control area will have a high weight factor, and therefore affect the index more than remote plants would. Initially the sensitivities will be set using off-line power flow studies, but long term plans are to have the sensitivities calculated near real-time by on-line power flow studies.

## PROCEDURE

The Reactive Power (MVAR) Monitor is one of three monitors described in DSO 303 and is to be used as a means of monitoring dynamic reactive reserve and triggering manual system changes to maintain dynamic reserve. If sufficient reserve cannot be maintained, DSO 303 gives guidance and ultimate authority to cut schedules if necessary. The calculated index is a more sophisticated measure of reactive reserve than a flat MVAR amount. The calculated index takes location and system conditions into consideration.

## ALARMS

Alarming is in two modes, color change and an audible alarm. The limit [an enterable field] is set manually to give warning before running reserve to the bottom. When we violate the calculated index as displayed on page 1, the graphic will change from GREEN to RED. The second graphics showing the calculated index is displayed in yellow. When the limit is violated, an AUDIBLE alarm will sound on the SCADA-R terminal. When the alarm sounds, click on the 'ALL ALARM' icon in the APPLIST icon box at the left of the screen. Click on the 'SILENCE' button at the upper right to silence the alarm. You will see a flashing message on the alarm page displaying "REACTIVE [MVAR] MONITOR VIOLATION DETECTED". The alarm will again be initiated when the actual calculated index goes above the limit to allow for going back to pre-violation limits.

*NOTE: The alarm limits are conservative, meant to alert the dispatcher to a potential problem rather than alarming at a critical operating point.*

## **DISCUSSION**

The index is computed for each critical voltage control area. It is planned to have indices for the following areas:

- 1.0 Puget Sound
- 2.0 Portland-Willamette Valley
- 3.0 West Side
- 4.0 Lower Columbia Region
- 5.0 Lower Snake Region
- 6.0 Mid Columbia Region
- 7.0 Upper Columbia Region
- 8.0 East Side

The PSST will be used for the platform initially, but when SCADA-R is implemented at Dittmer, the application will migrate to that platform.

Each powerhouse contributes MVAR support to a pre-determined region. A sensitivity factor is computed for each plant [initially this will be done from OFF-LINE Powerflow studies]. Later on this will be done using State-Estimator output and will be computed every 5 minutes. These sensitivity factors determine which Powerhouses contribute MVAR support to each region. Only those projects that contribute significant support from outside of a particular region are included in that region's index. As the system loads increase, the sensitivity factor for remote plants will decrease to where they are not part of the measured response. From the grouping of projects for each region, an index is computed reflecting the long-term dynamic voltage security. The regional index will then be displayed on the MVAR RESERVE AREA INDICES page. Each region will have the current actual position and the security limit displayed as a horizontal bar chart. In addition, the digital index, limit, and current MVAR Reserve for the region will be displayed too. The displays are set up to scroll up or down to get to the Region of interest.

*NOTE: This monitor does not predict transient voltage stability, only medium and long-term dynamic voltage stability.*

The individual plant data is displayed on a separate display MVAR RESERVE PLANT INDICES. To get to this display click on the Plant Name of interest. This display is also set up to scroll up and down to the particular Plant you want to see. On the Plant page you will see the actual MVAR being produced, the

maximum boost and buck capability, and the MVAR reserve in both boost and buck direction. In addition a digital quantity will be displayed showing the number of units in service, the number of units available [but not in service], and the number of units out of service and unavailable. Each plant will be identified along with the units on a bus voltage basis.

The individual PH Line data is displayed on a separate display MVAR RESERVE LINE INDICES page. On this page the actual MVAR, the maximum boost and buck capability and the MVAR reserve on a PH line basis. This display is also set up to scroll up and down through the list which is displayed together on a plant basis.

**Attachment 5 from a report entitled (California-Oregon Intertie Transfer and Voltage Support Study) VAR WARS, dated 11-20-96**

**Voltage Security Assessment - Reactive power and reactive power reserve monitoring**

We are developing voltage security assessment (VSA) involving monitoring of generator and SVC reactive power output and reactive power reserve. This is an EPRI-Tailored Collaboration project that is part of the Wide Area Measurement System development. NSR is the contractor. Initial implementation will be on the Power System Security Tools platform (April 1997) with final implementation on the EMS System in fall 1997.

The project responds to two recommendations of the August 10, 1996 WSCC disturbance report. Recommendation 2d calls for on-line security analysis and monitoring of key system parameters. Recommendation 7c states: "BPA shall implement Various off-line, on-line, and real-time monitoring tools to identify at-risk system operation conditions."

**BACKGROUND.** Generating plant reactive power and reactive power reserves are sensitive indicators of voltage security. Large area voltage instability usually will not occur until controls limit field current and reactive power. Field current limiting at one large generator may lead to cascading current limiting at other generators. SVC reactive power and reactive power reserve are likewise sensitive indicators of voltage security. High reactive power output and corresponding high reactive power transfer indicates system stress, voltage sensitivity and possible voltage depression such as that experienced on July 2 and August 10 (which led to angular instability).

Several utilities base voltage security assessment, and automatic or manual voltage collapse countermeasures on generator reactive power measurements. For example, Virginia Power [1], BC Hydro, Svenska Kraftnät [2], and others switch reactive power compensation based on generator reactive power. A policy of switching capacitor banks to keep generators near unity power factor has allowed Virginia Power to survive major disturbances.

BC Hydro [3], Florida Power and Light [4], and Swedish utilities [5,6] use generator reactive power level, along with HV or EHV voltage magnitude, for automatic load shedding and other countermeasures.

**DESCRIPTION.** VSA uses SCADA measurements from BPA switchyards to compute generator reactive power output. Measurements are switchyard

voltage, and real and reactive power on power plant lines. Power plant unit status from digital AGC telemetry is also used. For multi-unit plants, VSA computes the reactive power output and reserve for an equivalent generator.

We are proposing two main displays. The first is bar charts showing power plant reactive power output and capability. Operators can see which plants are approaching reactive power limits and take appropriate actions such as capacitor bank switching to reduce output. If plants are at or above their continuous reactive power capability, emergency actions may be necessary.

The second main display is bar charts showing VSA indices for different areas (Puget Sound area, Portland area, overall west side, and east side). The indices (scale of 0 to 100) are computed for each area based on weighted values of generator and SVC reactive power output divided by weighted generator and SVC reactive power capability. The basic idea is to avoid current limiting at critical plants. Higher weights are given to nearby plants and to large plants, meaning that current limiting at a large nearby plant will significantly reduce voltage security. Weights are computed from power flow program sensitivity analysis. Eventually, weights can be computed on-line using the on-line power flow program.

Other displays provide more details such as individual power plant line real and reactive power and trends of indices. The plants monitored are:

Chief J 1-16	Chief J 17-17	Coulee 1-18	Coulee 19-24
Centralia	Bonneville 11-18	The Dalles 5-22	John Day
McNary 1-12	Boardman	WNP-2	US Gen
Coyote Springs	Lower Snake	Maple Valley SVC	Keeler SVC

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**Attachment 6 from a report entitled (California-Oregon Intertie Transfer and Voltage Support Study) VAR WARS, dated 11-20-96**

**Summary Of BPA Development Of On-Line Power System Analysis Tools:**

Bonneville Power Administration (BPA) is currently using ESCA's Power System Security Tools (PSST) product to provide real-time analysis of power system conditions. Results of this program identify any thermal overloads or voltage problems due to real-time outages or flow patterns on the power system. The program is being used to study upcoming outages and the potential cumulative effect of these outages on the security of the power system.

Using SCADA real-time data from BPA's system and data from other utilities via Inter-utility Data Exchange as input, PSST creates a State Estimator case. This identifies any overloads or voltage problems for the power system as it is running at that time. The State Estimator runs automatically every 15 minutes. This State Estimator case can be then used as input to a Powerflow program, when the user can study the system further by adjusting generation levels, increasing or decreasing Intertie schedules or creating additional outages.

On-Line Contingency Analysis is an additional feature of PSST that is being implemented. Using a State Estimator case as input, Contingency Analysis will automatically run a pre-determined list of outages periodically (every 30 minutes) and display results for any contingency which will put the power system at risk for thermal overloads or voltage problems. BPA expects this feature to be on-line by March 1, 1997. This will provide information to the operators of any potential operating problems so preventive actions necessary to protect the power system can be taken.

At this time, BPA is involved in an intensive updating of the data base and a thorough evaluation of program performance and the anticipated completion date of this evaluation is March 1, 1997. The system was installed using a 1989 WSCC database, and while BPA Operation's has kept up to date with changes on the BPA power system, it is necessary to update the models of the interconnected utilities. BPA currently has a inter-utility data exchange with 6 utilities (BC Hydro, Puget Sound Power & Light, PG&E, Portland General Electric, Seattle City Light, and PacifiCorp) and expects to have data exchange with 5 additional utilities by summer of 1997. The system model must be improved to include the additional detail for those utilities. As BPA receives more real-time measurements from interconnected utilities, the accuracy of the results improve and confidence in predicted power system performance is increased.

Future enhancements to the program will include Dynamic Security Analysis (DSA) and Voltage Security Assessment (VSA). These programs will run automatically using a State Estimator case from PSST as the base case, and then run a Contingency Analysis-type of routine to identify any potential stability problems. The programs are under development at this time and BPA will add them to the On-Line Tools as they become available.

ESCA is developing a new program that will calculate the total transmission capability (TTC) of transmission paths for current system conditions, and look ahead 30 days using a load and outage forecast to predict future transmission path capacity. BPA is involved in the development of this product because this program will enhance power system security by predicting conditions where maximum capability on the transmission paths is reduced.

# Voltage Security Assessment

## COMPUTING INDICES

The BPA Voltage Security Assessment (VSA) project includes computation of area voltage security indices based on generator/SVC reactive power output, reactive power capability, and ability to effectively deliver reactive power. We use a scale from 0 to 100 where a low number means insecurity (important generators near reactive power limits with the possibility of voltage collapses). An alarm can be given at some threshold, perhaps 20.

An index is computed for each of the following areas (“voltage control areas”):

1. Overall West Side (Seattle/Portland load areas)
2. Portland (Willamette Valley/Southwest Washington)
3. Puget Sound
4. Overall East Side
5. Lower Columbia
6. Lower Snake
7. Mid Columbia
8. Upper Columbia

VSA index computation was weighted values of power plants/SVC reactive power outputs and reactive capabilities. Thirty power plants or SVCs are currently specified. See attached spreadsheet.

Indices are computed as follows:

$$\text{Index} = 100 \left[ 1 - \frac{\sum W_i \times Q_i}{\sum W_i \times Q_{mxi}} \right]$$

where subscript  $i$  represents a particular plant,  $W_i$  is a weight between 0 and 1,  $Q_i$  is the plant reactive power output, and  $Q_{mxi}$  is the plant continuous overexcited capability and is a function of MW loading. The index will be zero or negative if all plants are at or above their continuous reactive power limit.

Weights are based on relative sensitivity and plant size. We try to avoid current limiting at the most sensitive plants, but recognize that current limiting at a small plant is not critical. A large plant close to the voltage control area will have a high weight. The individual weights will be entries in matrix of voltage security areas and power plants/SVCs.

Weights can be computed as follows:

$$W_i = \frac{\Delta Q_i}{\Sigma \Delta Q_i} \times \frac{Q_{mxi}}{\Sigma Q_{mxi}}$$

where  $\Delta Q_i$  is plant reactive power increases for an increase in area load. The first term ranges from 0 to 1 and a large values means that, for a load increase, generation response at plant  $i$  is large compared to other plants; this is the sensitivity term. The second term also ranges from 0 to 1, and a large value means that the plant reactive power capability is large.

Weights are determined from power flow simulation sensitivity computation. Initially, weights are computed off-line using power flow base cases. The effect of outages or different operating conditions changing the sensitivities will be neglected. By August 1997, weights will be computed automatically based on current conditions using the PSST state estimator and on-line power flow. For simulated contingencies, the on-line power flow could compute weights and indices.

Different power flow modeling assumptions will also affect sensitivities to some degree. It's probably better, for example, to neglect high side voltage control.

Mechanically-switched capacitor and reactor banks can be controlled by the Maple Valley and Keeler SVCs. BPA does not use this automatic control, however, and so manually controlled banks will not be included in the  $Q_{mxi}$  for SVCs. SVCs will be treated like generators except that all ratings apply to reactive power delivered to the 230 kV bus.

Sensitivities can be computed from a base case by repeat power flow simulation. Additional reactive power load can be applied at area busses, with the power plant reactive power changes observed. Alternatively, percentage change in a power flow load in the zone or zones of the voltage control area can be made, with plant reactive power changes observed. It's also possible to compute the linear sensitivities from the Jacobian matrix of a solved power flow case.

Instead of an increase in area load, an increase in inertia or interface loading may be used.

## **APPENDIX D**

### **EPRI's ON-LINE VOLTAGE SECURITY ASSESSMENT (VSA) DEMONSTRATION**

Product Manager: Dominic Maratukulam, 415/855-7974, dmaratuk@epri.com

**Description:** On-Line VSA will continuously monitor the voltage stability of the grid using state estimated data from the energy management system (EMS). On-line VSA will complete an assessment of voltage security of the current system state within 20 minutes for large systems, providing various security indices for the operator and a list of contingencies that could lead to instability. It will also identify measures to mitigate an evolving voltage collapse, such as load curtailment, re-dispatching and emergency loading of VAR sources, etc. The tool will be capable of performing on-line studies of various operating decision strategies, such as options for power transfers and scheduling planned outages for maintenance.

**Benefits:** For voltage stability constrained utilities, VSA will allow increased utilization of grid assets while maintaining the reliability of power delivery. This is achieved through the calculation of limits dynamically using actual system conditions. A typical benefit might be a 15% increase in transmission capacity across a constrained 1,000 MW interface. Assuming 30% of this increased capacity could be used on average over a year and a \$10/Mwhr price differential across the interface, this could result in an annual financial benefit of \$3.9 million.

**Nature of Financial Benefit:** A potential 15-20% capacity increase for stability constrained corridors.

**Status:** The solution techniques in the presently available off-line voltage stability analysis program, VSTAB, are being used as the starting point for On-Line VSA. VSA will be developed and then demonstrated at several Host Utilities. Product development is being accomplished jointly by EPRI and BC Hydro under the EPRI-BC Hydro Alliance. The first demonstration of On-line VSA will be at BC Hydro. A VSA specification for BC Hydro is complete and work has progressed well on the VSA computational engine. Several modules are near completion, including contingency analysis and ranking module, and the fast time domain simulation module. Work has progressed well on the secure region computation module and the remedial action module. The BC Hydro VSA is expected to be on-line by \*6/98. Work on a second Host Utility demonstration has begun in late 1996 with an initial system assessment. A beta version VSA will be delivered in 1997 for use by other members. The commercial Version 1.0 will be available in 1998.

\* Six months after the new BC Hydro EMS becomes fully operational.

**Milestones:**

- 4/97 Initial prototype version of VSA working in factory
- 12/97 Release of Beta Version
- \*6/98 On-line prototype operational at BC Hydro control center
- 12/98 Release Version 1.0 of production grade voltage stability on-line program
- 12/98 Second Host Utility demonstration in place

## **APPENDIX E**

### **DESCRIPTION OF EXISTING AND PLANNED UNDERVOLTAGE LOAD SHEDDING PROGRAMS**

19 June 1996

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**SYSTEM OPERATING ORDER 6T-34**  
(Supersedes S.O.O. 6T-34 dated 20 December 1995)

**AUTOMATIC UNDERVOLTAGE LOAD SHEDDING**

**1.0 GENERAL**

This order describes operation of the automatic undervoltage load shedding remedial action scheme to maintain B.C. Hydro 500 kV system voltage stability and the system conditions used to arm the scheme.

An automatic undervoltage load shedding scheme has been implemented to prevent a voltage collapse of the integrated electric system following loss of major transmission or reactive power support facilities. The scheme will shed Vancouver Island loads and Lower Mainland loads individually or collectively, depending on the magnitude of the undervoltage condition and the amount of dynamic VAR reserve in the two load areas.

**2.0 RESPONSIBILITIES**

The System Control Centre (SCC) will direct Vancouver Island Control Centre (VIC) and Lower Mainland Control Centre (LMC) to arm and disarm the automatic undervoltage load shedding scheme as required in accordance with system conditions. VIC and LMC will be responsible to ensure connected load is available for shedding at all times and to allocate loads for shedding in different blocks. After load shedding has occurred, load restoration shall be coordinated by SCC.

### **3.0 DESCRIPTION OF THE SCHEME**

The automatic undervoltage load shedding scheme monitors a selected list of dynamic system conditions and will shed load until proper system voltages and VAR reserves are restored. The scheme consists of two independent subsystems, one at Vancouver Island and another at Lower Mainland, which can shed load in their respective areas, or jointly for more severe system problems.

Each subsystem monitors three key station bus voltages and a designated group of units for its VAR reserve, which is the remaining VAR boost capacity of the group. If the bus voltage drops below a set level or if the VAR reserve drops below a set level, its sensor will key a continuous signal to either VIC or LMC. At the control centre, the VAR reserve is ANDED with three different combinations of two bus voltages. After time delay (Ts2), load shedding will start and continue in incremental blocks until the initiating conditions have reset. A reduced time delay (Ts1) is used if both subsystems have simultaneously initiated load shedding. Refer to Attachment 1 of this order for a functional logic diagram of the scheme.

#### **3.1 Vancouver Island Subsystem**

The monitored list for the Vancouver Island sub-system are:

- Dynamic VAR source: total VAR output of VIT S/C1, S/C2, S/C3 and S/C4 (in % of its "true" capacity).
- Bus voltages: DMR230, VIT230 and SAT230.  
(Note: Low voltages at "SAT AND VIT" are not used to initiate automatic undervoltage load shedding because this condition can also be precipitated by local disturbances.)

#### **3.2 Lower Mainland Subsystem**

The monitored list for the Lower Mainland subsystem are:

- Dynamic VAR source: total VAR output of BUT units 1 to 6 (in % of its "true" capacity)
- Bus voltages: ING230, MDN230 and HPN230

Notes: 1) "True" capacity is based on connected units with AVRs in service. Any unit with its AVR out of service do not contribute to "true" capacity.

- 2) The Programmable Logic Controller (PLC), used to monitor the individual VAR reserve group, measures the "true" capacity of the S/C or generator unit automatically.
- 3) If the positive VAR capacity of a unit is restricted below its normal rating, P&C personnel will be notified to re-program new rating in the PLC.

### **3.3 Settings**

#### **Vancouver Island Subsystem**

Monitor Sensor	Monitor Setting
VIT S/C total VAR output	=95% true capacity
DMR230 kV	=221 kV
VIT230 kV	=220 kV
SAT230 kV	=220 kV

#### **Lower Mainland Subsystem**

Monitor Sensor	Monitor Setting
BUT unit total VAR output	=70% true capacity
MDN230 kV	=223 kV
HPN230 kV	=221 kV
ING230 kV	=220 kV

## 4.0 ARMING CONDITIONS

The automatic undervoltage load shedding scheme will be armed and disarmed by VIC and LMC under direction from SCC. The scheme is not required and should not be armed at times when transmission lines are taken OOS for voltage control during light load condition.

### 4.1 Arming Both VI and LM SubSystems

Conditions to arm the scheme are:

- a) when VSLIM data is not available during heavy load and/or heavy export periods;
- b) when operating near (say within 100 MW) or outside a VSLIM boundary, especially with one or more 230 kV lines OOS in the Lower Mainland or Vancouver Island;
- c) when the total dynamic VAR reserve for VIT S/Cs is less than 135 MVAR;
- d) when the total dynamic VAR reserve for BUT S/Cs is less than 360 MVAR.

### 4.2 Arming The VI Subsystem

The VI subsystem should be armed when:

- a) Vancouver Island is only connected to the Mainland via one 500 kV circuit (i.e. any of the parallel circuits OOS: 5L29/5L31, 5L30/5L32, 5L42/5L45).

**AND**

- b) the total load on Vancouver Island (plus Sechelt area load if 5L42 or 5L45 was the first contingency outage) exceeds the Vancouver Island generation plus HVDC loading, and 1L17/1L18 transfer capability.

## 5.0 MANUAL LOAD SHEDDING

Manual load shedding may be required to backup the automatic scheme.

To facilitate manual load shedding, the following procedures will be used:

- The SCC Dispatcher will notify the VIC and LMC Dispatcher of any impending requirements to initiate manual load shedding based on system conditions described in Section 4.0 of this order. This is the first alert.
- The SCC Dispatcher will cancel the first alert when load shedding is no longer required.
- While in the first alert and after occurrence of a contingency that will impact the ability of the electric system to maintain voltage stability (e.g. loss of a major 500 kV transmission line or a heavily loaded lower voltage transmission line, or loss of major voltage support equipment), the SCC Dispatcher will immediately inform the VIC and/or LMC Dispatcher of the outage. The SCC Dispatcher will also delegate responsibility to the ACC Dispatcher to monitor the key VAR reserve group and substation voltages in the area and initiate manual load shedding if these monitored quantities remain above or below their settings described in section 3.3.

When communication between SCC and the ACC is not immediate but the ACC Dispatcher can see that a major disturbance has occurred and the VAR reserve and voltages in the control area are steadily declining, the ACC Dispatcher can unilaterally take operating responsibility on an emergency basis to shed load.

A lack of VAR reserve is an early indication of voltage stability problems. To shed load manually, it is recommended the VIC and LMC Dispatchers monitor respectively the total VIT S/C VARS and the BUT plant VAR output. The following procedures can be followed for VIC and LMC after load shedding appears to be imminent to prevent a system voltage collapse.

At VIC

1. If VIT/SC VAR output is at or near maximum, shed block 1 and block 2 loads (approximately 265 MW) with the cable overload shedding facility.

2. If the VAR output on the VIT S/C units drop below 90% of its capacity, no further load shedding is required.

If the VAR output remains above 95%, shed the remaining 5 blocks of load (approximately 517 MW).

3. After load shedding, load restoration will be coordinated by SCC. The manual load shedding via the LMC Workstation connected to the L & G system is not yet commissioned into service. LMC will continue to use its existing SCADA to perform manual load shedding during the interim.

At LMC

1. If BUT plant output is at or near 75% of its capacity, shed Blocks 1&2 (approximately 284 MW) via SCADA.

2. If the VAR output from the BUT plant drops below 65% of its capacity, no further load shedding is required.

If the VAR output remains above 70%, shed Blocks 3, 4 & 5 (approximately 239 MW) via SCADA.

**6.0 DESIGNATED LOADS**

The designated loads to be shed are described in Tables 1 and 2 in the Attachment 2 of this order.

The amount of load to shed in the first block must be greater than 125 MW.

Indicates Revisions

## FRESNO UNDER-VOLTAGE LOAD SHEDDING SCHEME (ASHLAN, MCCALL, FIGARDEN SUBSTATIONS)

Trips distribution only based on potential from line side of breaker. Voltage must reach 207 kV on *all three phases* to pick-up relay. All distribution breakers with under-frequency tripping cut-in will be tripped. Based on '91 loading, available load drop for the 3 substations combined is approximately **160 MW**. Based on 6/96 loading, the available load drop was estimated to be **195 MW**.

**Anticipated Load Shed** = Approx. **105 MW** (Based on '91 Loads) , at Ashlan  
**Anticipated Load Shed** = Approximately **30 MW** (Based on '91 Loads), at McCall  
**Anticipated Load Shed** = Approximately **25 MW** (Based on '91 Loads), Figarden feeders

**Relay Pick-up** = 207 kV f-f primary =  $0.9 * 230 \text{ kV} = 103.5 \text{ V secondary f}$   
**Time Delay** = 7 seconds  
**Restoration:** awaits instructions from Fresno Grid Operator before performing manual reset of lock-out relay.

**In service dates:** ASHLAN -- 8/14/91  
McCALL - 8/15/91  
FIGARDEN 8/13/91

### V-Q Curve at McCall 230 kV Bus

6/17/94 Study (Study must be updated)

Worst Contingency during Fresno Peak = Loss of Gates-McCall 230 kV line

Pre-Contingency Voltage at McCall = 218 kV  
Post-Contingency Voltage at McCall = 207 kV (about 310 MVAR Margin to Post-Contingency)  
Pre-Post kV = 11 kV

#### Distribution Voltage Criteria

218 kV is within our Minimum Normal Voltage range (217 - 226 kV) for Urban Area Load Buses.  
207 kV is below our Minimum Emergency Voltage range (210 - 219 kV) for Urban Area Load Buses.

## **Boise Bench C-231 (93.7 MVAR) capacitor RAS control and Undervoltage load shedding program.**

The following describes a proposed scheme for the Boise Bench C231 shunt capacitor automatic closing control logic, and one required to initiate undervoltage load shedding through the EMS system.

### **C-231 Automatic Closing Scheme.**

The closing control logic is designed to ensure that C231 will be automatically switched on during significant loss of Idaho's Eastern resources during high import conditions from the Northwest. The additional flows superimposed on the 230kV lines into Boise Bench from the West, during these circumstances, could lead to a drain in our reactive resources if adequate voltage support is not available in our area. It is mainly for this reason, that timely switching of the new bank (C231) is critical to prevent further voltage decline. The proposed scheme is intended to achieve just that.

The actual control logic should preferably be implemented via a Programmable Logic Controller, although both a relay with a flexible enough programmable logic or the current EMS system might be capable of the task. Use of a PLC will provide ease of implementation and the higher degree of flexibility needed to accommodate future modifications that may be required under different system conditions. Additionally a simpler hardware/software interface and broader accessibility to field personnel will cut down, when needed, the effective re-programming time to a fraction of that obtained through the other two alternatives.

As indicated in the appended schematic, automatic closure of the bank can take place via three separate criteria. The first and more sensitive one is through a power flow level detector (PWR), which will normally be enabled, when the total MW flows into Boise Bench, on the Brownlee lines is above a pre-determined minimum. This supervisory condition should reduce unnecessary closing operations of the bank. With power flows above the prescribed minimum, meeting either one of the following conditions will suffice for bank closure:

- a)  $\Delta PWR$  : MW change into Boise Bench on either one of the Brownlee lines above a prescribed minimum. Note that each line is to be monitored separately and the change measured over an adjustable time interval.
- b)  $\Delta I$  : Current magnitude change on either one of the Brownlee lines above a prescribed minimum. Highest loaded phase or average phase loading is an acceptable compromise. Note that each line is to be monitored separately and the change measured over an adjustable time interval.
- c)  $Q_{cond}$  : Reactive or Current magnitude on either one of the Boise Bench synchronous condensers over a prescribed minimum. Again if current measurement is to be used, either highest loaded phase or average phase loading will suffice. Condition should be present over an adjustable time interval.

The second and third criteria, are independent of transfer level information and are intended to pick up on the more gradual changes in line loading and/or serve as last resort indicators of the need for capacitor switching. One is based on line overload (based on highest loaded phase, or average phase current on either one of the Brownlee lines) exceeding a pre-determined limit for an adjustable time period. The last criterion relies on the 230kV and the

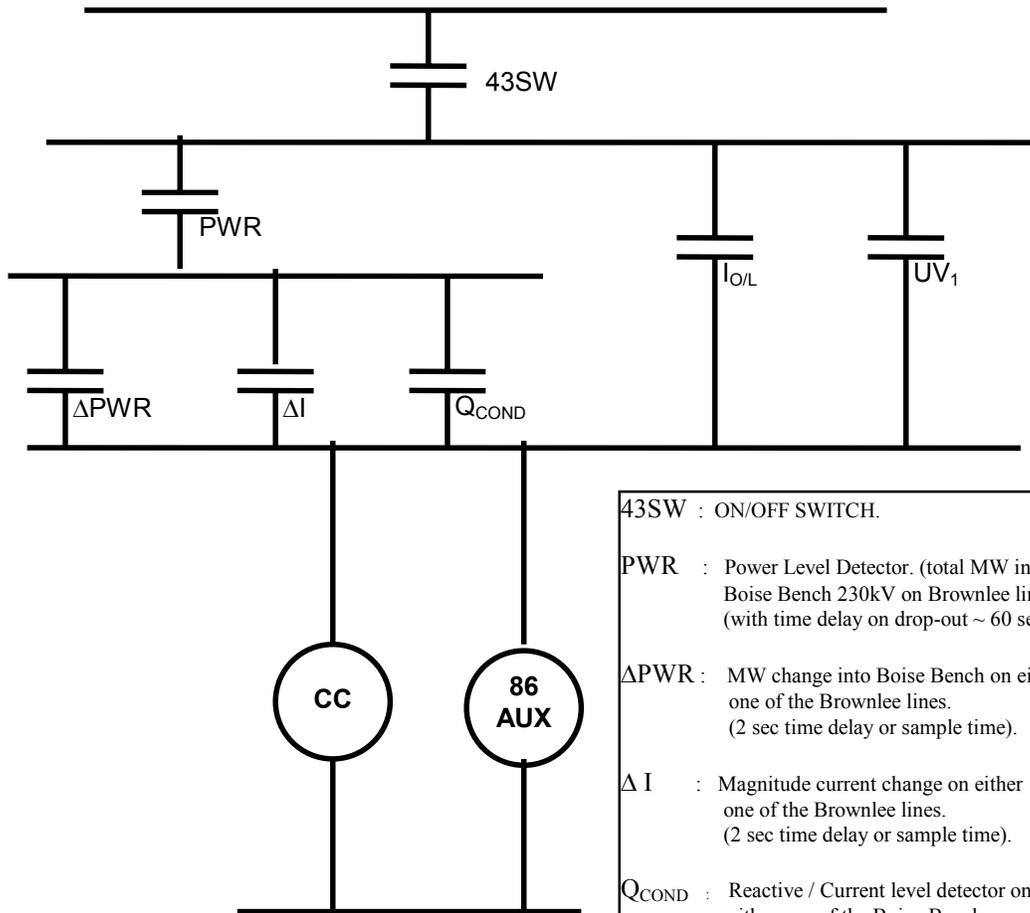
138kV bus voltages (positive sequence voltage or three phase voltage with provisions for fuse failure) and will initiate closing of the bank, when either one falls below a pre-specified level for an adjustable time period.

### **Undervoltage Load Shedding Scheme.**

Here the intent is to utilize the intelligence already built into the automatic closing control logic, to securely and dependably initiate the undervoltage load shedding program. It should be noted that the proposed scheme's function is to provide the go or no-go decision to the load shedding program currently executed by the EMS system. Further improvements, in the reliability of the scheme will require redundant communication and a more secure tripping logic at the remote sites (load dropping stations).

If the capacitor closing signal is asserted (86-AUX, also with adjustable delay on drop out) and there is no current being drawn by the shunt bank after a pre-determined time delay (T1), the load shedding program will be initiated. Similarly if an undervoltage condition (UV2), also based on 230 and 138kV bus voltages continues to exist for an adjustable time period permission is given to initiate the load shedding program. At this time the EMS will initiate automatic tripping of up to 300 MW under heavy load conditions. Additionally the dispatcher has access to a manual load shedding page within the EMS, that could be used to expedite shedding additional 500 MW of load.

## BOISE BENCH C-231 AUTOMATIC CLOSING SCHEME.



43SW : ON/OFF SWITCH.

PWR : Power Level Detector. (total MW into Boise Bench 230kV on Brownlee lines) (with time delay on drop-out ~ 60 secs).

ΔPWR : MW change into Boise Bench on either one of the Brownlee lines. (2 sec time delay or sample time).

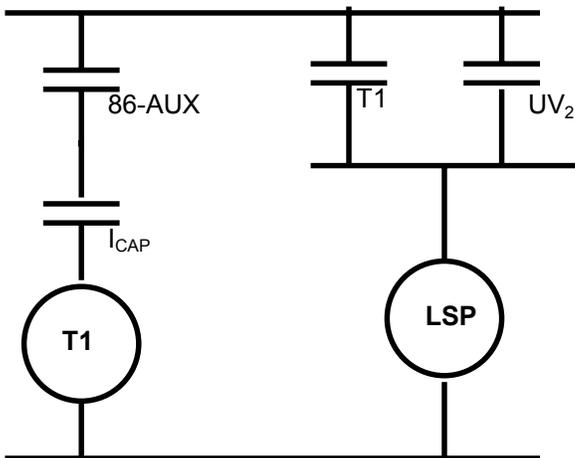
Δ I : Magnitude current change on either one of the Brownlee lines. (2 sec time delay or sample time).

Q<sub>COND</sub> : Reactive / Current level detector on either one of the Boise-Bench Synchronous condensers. (4 sec time delay or sample time)

I<sub>O/L</sub> : Current magnitude level detector on either one of the Brownlee lines. (2 sec time delay or sample time).

UV<sub>1</sub> : Under voltage level detector on 230 / 138 kV buses. (2 sec time delay or sample time).

### UNDERVOLTAGE LOAD SHEDDING PROGRAM INITIALIZER.



T1: Adjustable timer.

I<sub>cap</sub>: Phase current magnitude level detector on C231 bank.

UV<sub>2</sub>: Undervoltage level detector on 230 / 138 kV buses. (2 sec time delay or sample time).

LSP: Undervoltage load shedding program.

86-AUX: C231 closing logic asserted ( w/ delay on drop out).

## **Sacramento Valley UV Load Shedding Program**

In a letter to area utilities, dated March 26, 1997, the Sacramento Valley Study Group (SVSG) recommended that area utilities implement an under voltage (UV) load shedding program. The following UV load shedding parameters were recommended:

SMUD	230 MW
PG&E	150 MW
City of Roseville	20 MW
Total	400 MW

Initiating Voltage 210-212 kV (under review)  
Time Delay 5-10 seconds

The UV load shedding scheme should be in-service by July 1, 1997.

SVSG is preparing a report documenting study results leading to this recommendation. The report should be finalized by the end of May. SVSG is working with PG&E to coordinate the Sacramento area UV load shedding program with the UV load shedding program planned for the San Francisco Bay area. Upon further investigation, SVSG may refine the set point for the initiating voltage and time delay.

## **PROCEDURES FOR THE EPE UNDERVOLTAGE LOAD SHEDDING SCHEME:**

The following procedures were used in the analysis:

1. A number of various system configurations were considered. Single contingencies of EPE's 345 kV tie-lines were taken and V-Q curves corresponding to these contingencies were developed for each 345 kV bus. The single realistic scenario which represents the case with the lowest operating margins during the single 345 kV contingencies was found by comparison of these V-Q curves.
2. This scenario was modified (by raising Southern New Mexico Import (SNM) level) in order to "bring" the V-Q curve instability point as close to zero MVAR margin point as possible. This case was then stored ("instability case"). The "instability case" was used in order to determine the potentially unstable voltage levels at every bus in EPE system.
3. The ALIS version of the "instability case" was used in a single contingency analysis; each transmission line in EPE service area was dropped and voltages at every distribution substation were monitored.
4. The results of the V-Q curve and single contingency analysis were combined with the following information available for each substation: the size of load, the number of distribution feeders, the location of the substation relative to the generation and SVG, the availability of supervisory control at this substation, the type of customers this substation serves (restricted buses), the nature of load at this substation (power factor), the physical limitation for the installation of the load shedding relay equipment. The following is the list of factors derived from the V-Q curve and contingency analysis:
  - The relative "stiffness" of the considered bus
  - The relative impact of MVAR injection at the considered bus on the 345 kV system. (The voltage impact of MVAR injection at the considered bus was monitored at all EPE 345 kV busses and plotted on the V-Q curve for the considered bus. This impact can be visualized from the V-Q curve as the slope of the voltage for the monitored busses (345 kV busses) relative to the slope of the voltage of the considered bus.
  - The voltage sensitivity of the considered bus to single contingencies on the underlying system.

- The relative value of the critical voltage (instability voltage) derived in the V-Q curve analysis as it compares to the contingency voltage at the same bus and 0.95 P.U.
5. The trigger voltage for each bus were determined as the lowest voltage between following voltages.
- The voltage at this bus corresponding to the “instability case”, as it follows from V-Q curve analyses, plus an addition 0.01 P.U.
  - The lowest single contingency voltage for this bus
  - A minimum trip voltage of 0.95 P.U.
6. The time delay was set for each bus in every category. The time delay was spread in the range of 5-11 seconds in order to avoid false trips due to the transient conditions as well as to protect the system from an excessive and unnecessary load tripping (if all relays would operate simultaneously).

The scheme was designed to preserve integrity of EPE system against unplanned events that may lead to a complete EPE's system blackout.

The undervoltage relays cover about 55% of EPE load.

The trigger point is set individually for each installation. The trigger voltage varies for each bus (the values of trigger voltages are in the range of 0.89 P.U. and 0.95 P.U.).

The time delay for load tripping following activation of the trigger voltage is set for each bus (the time delay used varies in between five and eleven seconds, with one second increment).

The feeders that carry a "critical load" (hospitals, police, radio stations) were excluded from the undervoltage load shedding scheme.

## **PUGET SOUND UNDERVOLTAGE LOAD SHEDDING RELAYS**

Since the winter of 1990-91, the Puget Sound Undervoltage Load Shedding Program has been activated each year between mid-November until the end of April. The area utilities have applied undervoltage relays to trip loads for severe contingencies during peak winter loads.

PSE, SCL, SPUD, TCL, BPA use undervoltage relays to trip breakers supplying buses, feeders, or subtransmission lines. The breakers and their loads are grouped into three levels to mitigate increasing severity of reduced voltage. At each level, sufficient breakers are selected so that each utility trips about 5% of their total load. The sum of loads at all three levels in the Puget Sound Basin is about 1800 MW, which is 15% of a total 12,000 MW winter peak.

Each undervoltage relay is installed to monitor a substation bus voltage, and to trip selected breakers at that bus. The relays operate when the voltage is below a set threshold, for a minimum time duration. The voltage threshold setting is determined as a percent (shown below) times the lowest normal bus voltage measured during the past two winter peak load periods at that bus.

- (a) Each utility trips breakers serving 5% of load when monitored bus voltages fall to 90% or lower of normal for a minimum of 3.5 seconds.
- (b) Each utility trips breakers serving 5% of load when monitored bus voltages fall to 92% or lower of normal for a minimum of 5.0 seconds.
- (c) Each utility trips breakers serving 5% of load when monitored bus voltages fall to 92% or lower of normal for a minimum of 8.0 seconds.

Before Schultz Substation was constructed, BPA applied direct load tripping to an aluminum smelter for a double line loss of Coulee-Raver 500 kV. Schultz Substation reduced the need for load tripping by connecting the lines with breakers in the middle, along with two other 500 kV lines. The direct load tripping is not employed at this time.

**APPENDIX F**

**EXCERPTS FROM BPA BLUE RIBBON PANEL REPORT**

## **System Study Margin - Panel Assessment**

### **Introduction**

Following presentations by the Bonneville Power Administration (BPA) Staff the Chair polled the Panel concerning their position regarding the acceptability of reactive margins employed to establish the COI and PDC1 transfer capabilities based on Northwest system performance. The Panel endorses the study methodology and the recommended post-contingency V-Q analysis margins of not less than 600 MVAR for N-1 outages and 400 MVAR for N-2 common mode outages. The adequacy of the margin was supported by P-V analysis. This margin should be periodically reviewed. It was noted for the August 10th system topology, the proposed screening tests would have predicted the collapse. (See Appendix C).

### **Performance Level A-B-C Contingencies**

The consensus view of the panel was an expression of acceptance of the above 600/500 MVAR V-Q margin when substantiated by P-V analysis or another complementary method. V-Q analysis alone is not convincing. It was brought out that the demonstrated MW margin for the P-V cases presented is in line with industry practices. In the near term, the panel endorses a 600/400= MVAR margin for both planning and operating purposes. This margin may be relaxed at a later date as better tools and information become available which reduce the elements of uncertainty. Other methods of analysis, particularly dynamic simulation, should be applied in marginal cases to confirm in detail that the Council's Criteria are met. The above recommendations apply to disturbances both inside and outside the NW system as they relate to the COI.

### **Performance Level D Contingencies**

Regarding Performance Level D, contingencies need to be examined to test the security of the system to ensure that uncontrolled cascading disturbances do not occur. Other situations not included in Level D warranting attention may be identified by the Council and should include loss of the COI from a common mode event.

## **Other Issues**

Other VAR related issues which should be addressed to improve system VAR capability for reliability purposes include:

- Accurate reporting of present generator VAR capability both for planning purposes and in real-time.
- Minimization of generator VAR limitations
- Implementation of cost effective unwatered turbine capability, and
- Maximization of real-time dynamic VARS.

As a general principle, utilities need to be prepared for system separation such as could occur for loss of the COI, and seek to contain and minimize the extent of such disturbances and to facilitate restoration of ties, then load.

## Reactive Margin

At the December 5-6, 1996 meeting BPA presented study results based on a post-contingency 600 MVAR V-Q margin for N-1 events and a 400 MVAR V-Q margin for N-2 common mode events. The Panel had two general concerns. First, it was important to the Panel that the work be benchmarked to indicate what MW margin this corresponds to; the panel suggested use of P-V analysis. Studies presented by BPA at the January 27-28 meeting using P-V analysis helped confirm the results of the V-Q analysis. A list of uncertainties that should be given consideration in establishing planning and operating margin includes:

- a) BPA customer reactive demand greater than assumed
- b) Approximations in studies (Planning & Operations)
- c) Unknown outages on the BPA System
- d) Unknown outages on neighboring systems
- e) Unit trips following major disturbances
- f) Lower voltage line trips following major disturbances
- g) Unknown variations on neighboring dispatch
- h) Large and variable reactive exchanges with neighbors
- i) Unknown reactive constraints on neighbors generators
- j) Unknown load characteristics
- k) Risk of second major event during the 30-min. Adjustment period
- l) Not being able to re-adjust adequately to get back to a secure state
- m) Increases in COI flows following major contingencies due to on-system undervoltage load shedding
- n) On-system reactive resources not responding
- o) Excitation limiters responding prematurely
- p) possible RAS failure

Following presentations by the Bonneville Power Administration (BPA) Staff the Chair polled the Panel concerning their position regarding the acceptability of reactive margins employed to establish the COI and PDC1 transfer capabilities based on Northwest system performance. The Panel endorses the study methodology and the recommended post-contingency V-Q analysis margins of not less than 600 MVAR for N-1 outages and 400 MVAR for N-2 common mode outages. The adequacy of the margin was supported by P-V analysis. This margin should be periodically reviewed. It was noted for the August 10th system topology, the proposed screening tests would have predicted the collapse. (See Appendix C).

## Performance Level A-B-C Contingencies

The consensus view of the panel was an expression of acceptance of the above 600/500 MVAR V-Q margin when substantiated by P-V analysis or another complementary method. V-Q analysis alone is not convincing. It was brought out that the demonstrated MW margin for the P-V cases presented is in line with industry practices. In the near term, the panel endorses a 600/400= MVAR margin for both planning and operating purposes. This margin may be relaxed at a later date as better tools and information become available which reduce the elements of uncertainty. Other methods of analysis, particularly dynamic simulation, should be applied in marginal cases to confirm in detail that the Council's Criteria are met. The above recommendations apply to disturbances both inside and outside the NW system as they relate to the COI.

## Performance Level D Contingencies

Regarding Performance Level D, contingencies need to be examined to test the security of the system to ensure that uncontrolled cascading disturbances do not occur. Other situations not included in Level D warranting attention may be identified by the Council and should include loss of the COI from a common mode event.

## Other Comments

The Panel emphasized the need for P-V analysis to verify the rating of the Interties and also to establish voltage limits by which the dispatcher can be warned.

***The Panel is not convinced that a study margin is sufficient if key generators are at their reactive limits. However, the studies presented indicated margins existed on a number of key generators.***

***Some additional effort needs to be applied to the angle problem to ensure that the reactive margin contains sufficient and adequately distributed spinning reactive reserve available to prevent angular instability, at least up to the point where the reactive margin is exhausted.***

Until the interconnected systems develop a VAR exchange policy and controls are in place to adhere to such policies, ***planners should make their VAR margins sufficient to handle the likely VAR exchanges indicated by experience.***

***The Panel would like to see better coordination in the studies of all types of reactive sources.*** For example, if key generators are at reactive limits, the proposed 600/400 MVAR reactive margin may not be adequate for a next contingency. ***There should be an operational policy to shift reserve from static VARS to dynamic VARS in order to maximize dynamic VARS available for responding to the next event.***

## **Reactive Margin**

Key among various System Reactive Study assumptions was the reactive margin against which system performance should be evaluated and used to establish the COI and PDCI maximum transfer levels based on Northwest system performance. Such reactive margins are not established by the Council's Reliability Criteria.

The Panel endorses a post-contingency V-Q analysis margin of not less than 600 MVAR at critical 500-kV buses for N-1 outages and 400 MVAR for N-2 common mode outages. The adequacy of these margins was supported by P-V analysis. These margins should be used in the near term for both planning and operating purposes. (See Appendix C).

The Panel also recommends that these margins be periodically reviewed. The margins may be relaxed at a later date as better tools and information become available which reduce the elements of uncertainty. Other methods of analysis, particularly dynamics simulation, should be applied in marginal cases to confirm in detail that the Council's Reliability Criteria are met. It is recognized that system changes and operating experience must also be factored into any proposed future reactive margin increases or decreases.

The above recommendations apply to the evaluation of disturbances both inside and outside the Northwest system as they relate to the COI, and should be evaluated by the Council for disturbances outside the Northwest area.

## **APPENDIX G**

### **NERC PLANNING STANDARDS ON REACTIVE POWER PLANNING AND UNDERVOLTAGE LOAD SHEDDING**

# **NERC Planning Standards**

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## **I. System Adequacy and Security**

## **D. Voltage Support and Reactive Power**

### **Introduction**

Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (Mws), reactive power (MVAR) cannot be transmitted over long distances and must be supplied locally.

### **Standard**

- S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.**

#### **Measurements**

- M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems. Documentation of these assessments shall be provided to the Regions and NERC on request. (S1)

# **NERC Planning Standards**

## **I. System Adequacy and Security**

## **D. Voltage Support and Reactive Power**

- M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:
- a. Coordination of generator step-up transformer impedance and tap specifications and settings,
  - b. Calculation of underexcited limits based on machine thermal and stability considerations, and
  - c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges. (S1)

### **Guides**

- G1. Transmission owners should plan and design their reactive power facilities so as to ensure adequate reactive power reserves in the form of dynamic reserves at synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) in anticipation of system disturbances. For example, fixed and mechanically-switched shunt compensation should be used to the extent practical so as to ensure reactive power dynamic reserves at generators and SVCs to minimize the impact of system disturbances.
- G2. Distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems.
- G3. At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less. If a synchronous generator does not meet this requirement, the generation owner should make alternate arrangements for supplying an equivalent dynamic reactive power capability to meet the area's reactive power requirements.
- G4. Reactive power compensation should be close to the area of high reactive power consumption or production.

- G5. A balance between fixed compensation, mechanically-switched compensation, and continuously-controlled equipment should be planned.

## **NERC Planning Standards**

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### **I. System Adequacy and Security**

### **D. Voltage Support and Reactive Power**

- G6. Voltage support and voltage collapse studies should conform to Regional guidelines.
- G7. Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.
- G8. Consideration should be given to generator shaft clutches or hydro water depression capability to allow generators to operate as synchronous condensers.

## **NERC Planning Standards**

### **III. System Protection and Control**

### **E. Undervoltage Load Shedding**

#### **Introduction**

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

It is imperative that undervoltage relays be coordinated with other system protection and control devices used to interrupt electric supply to customers.

#### **Standards**

- S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.**
- S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.**

#### **Measurements**

- M1. Those entities owning or operating UVLS programs shall coordinate and document their UVLS programs including descriptions of the following:
  - a. Coordination of UVLS programs within the subregions, the Region, and, where appropriate, among Regions.
  - b. Coordination of UVLS programs with generation protection and control, UFLS programs, Regional load restoration programs, and transmission protection and control programs.

## **NERC Planning Standards**

### **III. System Protection and Control**

### **E. Undervoltage Load Shedding**

- c. Design details including size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.

Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request. (S1, S2)

- M2. Those entities owning or operating UVLS programs shall ensure that their programs are consistent with any Regional UVLS programs and that exist including automatically shedding load in the amounts and at locations, voltages, rates, and times consistent with any Regional requirements. (S1)
- M3. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems. (S1)
- M4. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UVLS program. Documentation of the UVLS technical assessment shall be provided to the appropriate Regions and NERC on request. (S1)
- M5. Those entities owning or operating UVLS programs shall have a maintenance program to test and calibrate their UVLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)
- M6. Those entities owning or operating an UVLS program shall analyze and document all system undervoltage events below the initiating set points of their UVLS programs. Documentation of the analysis shall be provided to the appropriate Regions and NERC on request. (S1)

## **NERC Planning Standards**

### **III. System Protection and Control**

### **E. Undervoltage Load Shedding**

#### **Guides**

- G1. UVLS programs should be coordinated with other system protection and control programs (e.g., timing of line reclosing, tap changing, overexcitation limiting, capacitor bank switching, and other automatic switching schemes).
- G2. Automatic UVLS programs should be coordinated with manual load shedding programs.
- G3. Manual load shedding programs should not include, to the extent possible, customer demand that is part of an automatic UVLS program.
- G4. Assessments of UVLS programs should include system dynamic simulations that represent generator overexcitation limiters, load restoration dynamics (tap changing, motor dynamics), and shunt compensation switching.
- G5. Plans to shed load automatically should be examined to determine if acceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated. If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided. If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability. If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

**APPENDIX H**  
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