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West Coast Utility Transmission Benefits of Superconducting Magnetic Energy Storage

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REPORT SUMMARY

West Coast Utility Transmission Benefits of Superconducting Magnetic Energy Storage

Real-power modulation with superconducting magnetic energy storage (SMES) provides effective transmission system control and enables increased transmission loading. This project was undertaken to evaluate the area-wide transmission enhancement potential of SMES, a topic that had not been previously studied in detail.

INTEREST CATEGORIES

Facts and substations
Transmission access evaluation
Power system operations and control
Overhead planning, analysis and design
Power conditioning
Emerging technologies

KEYWORDS

Superconducting magnetic energy storage (SMES)
Advanced storage systems
Transmission stability
Power system control

BACKGROUND EPRI has supported SMES development during the past 15 years, with emphasis on developing viable components and system designs, understanding and reducing costs, and determining and promoting understanding of the potential value of SMES plants to electric utilities. Both costs as well as benefits must be understood in order to proceed with commercialization of SMES. On the cost side, a companion project (TR-103717) has produced the first detailed cost model for moderate to large-scale SMES plants. Early EPRI assessments of the benefits of SMES focused primarily on the ability of this technology to lower the costs of providing load-leveling and dynamic generation services (so-called "ancillary services", such as spinning reserve and frequency control). SMES-backed flexible ac transmission system (FACTS) devices offer EPRI member utilities an unprecedented opportunity to control their own destiny in emerging, open-access power markets. EPRI members will be uniquely positioned to gain an early foothold in these new markets through application of EPRI products involving SMES technology.

OBJECTIVE To identify and evaluate the potential for SMES to enhance transmission stability and increase the power transfer capacity of selected transmission corridors in the southwestern region of the North American power system

APPROACH The ability of SMES to increase stability-limited transmission capacity in the Western System Coordinating Council (WSCC) power system was assessed in scenarios representing post-1999, heavy summer conditions, using the Extended Transient/Midterm Stability Package, developed by EPRI. Control of contingency-induced oscillations was simulated using a 5000-bus model. Case studies addressed the site-and system-specific interests of major west coast utilities' transmission planners, who served as project advisors. SMES control effectiveness was evaluated in each case and compared with other control options.

RESULTS SMES real-power modulation was shown to be effective in damping electromechanical oscillations resulting from major system disturbances. A moderately sized SMES device appears capable of increasing transmission capacity into the Southern California region by as much as 500 MW. SMES would show yet higher value if utilized in a dual real and reactive power control mode, with other enabled benefits taken into account.

EPRI PERSPECTIVE This project is the first detailed evaluation of transmission enhancement benefits enabled by SMES using software programs contained in the EPRI-developed Power System Analysis Package (PSAPAC). With PSAPAC used in conjunction with the full WSCC model of the western power system, SMES transmission benefits have been evaluated on a far more detailed and credible basis than has been achieved in previous work. Results confirmed the expectations of the system planners that SMES controllers could be utilized to alter bulk power transmission in both time and space to better accommodate both physical system constraints and attractive power transaction opportunities.

Because of the complexities of the analysis, this project studied only one system configuration, that of a 1999 "heavy summer" case. Further studies of this type will be necessary to broaden our understanding of the system-specific control capabilities provided by SMES. In particular, additional site-specific studies of SMES devices providing simultaneous real and reactive power control at key locations in the western power system are warranted.

With a potential impact similar to that of fiber-optics and satellites on telecommunications, SMES may soon become the breakthrough technology altering the technological and business landscape in the electric power industry. EPRI member utilities who have a stake in other important power corridors in the U.S., should also consider SMES controllers.

PROJECT
RP 2572-13
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West Coast Utility Transmission Benefits of Superconducting Magnetic Energy Storage

TR-104803
Research Project 2572-13

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ABSTRACT

A scoping study is described that assessed the ability of superconducting magnetic energy storage (SMES) to improve the stability and power transfer capacity of selected pathways in the utility transmission system serving Southern California. Work was guided by transmission planners from five major west coast utilities known, for the purpose of the study, as the West Coast Utility Group (WCUG). The scope of analyses focussed on a working case set of 11 system contingency scenarios consisting of the 5 base cases and 6 sensitivity cases identified by the WCUG as being of special interest under the increased loading conditions expected beyond the end of this century. The transmission enhancement potential of SMES was analyzed using the Extended Transient/Midterm Stability Package, developed by the Electric Power Research Institute. The simulations and analyses utilized a 5000-bus 1999 heavy summer model of the western North American power system developed by utility members of the Western Systems Coordinating Council. The study evaluated the control effectiveness of SMES in each scenario and compared SMES with other options.

ACKNOWLEDGMENTS

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GLOSSARY

ac	alternating current
AGC	automatic generator control
BNW	Battelle Northwest
BPA	Bonneville Power Administration
dB	decibel(s)
dc	direct current
EOR	East-of-River
EPRI	Electric Power Research Institute
ETMSP	Extended Transient/Midterm Stability Package
FACTS	flexible ac transmission system
Hz	hertz
IPP	Intermountain Power Project
kV	kilovolt
LADWP	Los Angeles Department of Water and Power
MJ	megajoules
MW	megawatt
MWh	megawatt hours
NPV	net present value
PAST	Pacific and Southwest Transfer
PDCI	Pacific DC Intertie
PG&E	Pacific Gas and Electric
PSAPAC	Power System Analysis Package
SCE	Southern California Edison
SCIT	Southern California Import Transmission
SDG&E	San Diego Gas and Electric
SMES	superconducting magnetic energy storage
SSSP	Small-Signal Stability Package
SVC	static-var compensation
VAR	volt-ampere, reactive
WCUG	West Coast Utility Group
WOR	West-of-River
WSCC	Western Systems Coordinating Council

EXECUTIVE SUMMARY

A scoping study was undertaken to assess the ability of real-power modulation provided by superconducting magnetic energy storage (SMES) to increase the stability and power transfer capacity of selected transmission pathways in the western North American power system. The work was guided by transmission planners from five major west coast utilities known, for the purpose of the study, as the West Coast Utility Group (WCUG). The transmission enhancement potential of SMES was analyzed using the Extended Transient/Midterm Stability Package (ETMSP), developed by the Electric Power Research Institute (EPRI). This software enabled evaluation of SMES dynamic control capability using a 5000-bus 1999 heavy summer model developed by utility members of the Western Systems Coordinating Council (WSCC).

For heavy power transfers from Arizona to California, one of the critical disturbances that results in electromechanical oscillations is a three-phase fault at the Palo Verde 500-kV bus, followed by a loss of the Palo Verde-North Gila 500-kV line. This line, near the Colorado river, is one of the major tie lines between Arizona and Southern California. Power flow on lines comprising the East-of-River (EOR) and West-of-River (WOR) transmission corridors is used to define overall system loading conditions. The Southern California Import Transmission (SCIT) Nomogram is used to define the stability-limited imports available to Southern California. Table S-1 summarizes the WCUG-recommended cases that formed the principal case set assessed in the study. The benchmark load conditions, SCIT-1 and SCIT-2, derived from the 1999 heavy summer model, were calibrated such that a marginally-damped response (i.e., an electromechanical oscillation with near-zero damping) occurs as a result of the Palo Verde-North Gila contingency. The loading conditions were determined by adjusting Midway-Vincent and WOR flows for SCIT-1 and SCIT-2, respectively. These responses define benchmark cases HS1 and HS2.

The remaining benchmark cases, HS3 through HS5, were designed to evaluate the potential of SMES to improve the function of remedial action schemes. These five benchmark cases, the six sensitivity cases, and other cases to address issues and interests raised during the course of the study, were used to evaluate desired SMES control functions under these benchmark loading conditions and case set.

Table S-1
Working Case Set

a) Benchmark Loading Conditions

Case	WCUG Recommended Baseline Loadings
SCIT-1	EOR = 7000 MW; WOR = 9400 MW
SCIT-2	EOR = 7000 MW; Midway-Vincent = 3600 MW

b) Benchmark Cases

Case	Loading	Modeled Contingency
HS1	SCIT-1	3ϕ fault @ Palo Verde, loss of Palo Verde-North Gila line
HS2	SCIT-2	3ϕ fault @ Palo Verde, loss of Palo Verde-North Gila line
HS3	SCIT-2	Pacific DC Intertie (PDCI) bipole outage[(a)]
HS4	SCIT-1	Intermountain Power Project (IPP) DC bipole outage[(a)]
HS5	SCIT-2	3ϕ fault @ Table Mountain, loss of Table Mountain-Tesla, Table Mountain-Vaca Dixon lines[(a)]

(a) Switching sequences defined in 1994 Pacific and Southwest Transfer (PAST) Subcommittee Handbook (Mackin et al. 1994).

c) Sensitivity Cases

Case	Benchmark	SMES Control Objective
HS6	HS1	Increase WOR loading by 500 MW
HS7a	HS2	Increase EOR loading by 500 MW
HS7b	HS2	Increase EOR and WOR loading by 500 MW
HS8	HS3	Reduce remedial action generator dropping
HS9	HS4	Reduce remedial action generator dropping
HS10	HS5	Reduce remedial action generator dropping

The minimum SMES size required to provide stability enhancement was determined by evaluating the contingency cases with loadings exceeding marginally-damped conditions. With SMES included, and an appropriately-designed modulation control, a stable system response was observed when sufficient power modulation was provided. The potential of SMES modulation to increase transmission loadings beyond the marginally-damped conditions is shown in Figure S-1. Increases in EOR, WOR, and simultaneous increases in both corridors are given with SMES located at the Lugo 500-kV bus, which was found to be a common site where SMES could provide beneficial control for most of the sensitivity cases analyzed. As expected, the control leverage (ratio of increased transmission loading to SMES power) varied depending on the location of the control insertion point and control objective. The highest control leverage found was 3:1 at the point where 100 MW of SMES power increases EOR capacity by 300 MW.

The ability of SMES to offset remedial action schemes was evaluated for three contingencies. Two of these cases (HS8 and HS9) investigated the ability of SMES to reduce the amount of generator dropping required when dc interties are lost. Results indicated that a SMES unit located at Lugo can compensate the need to drop generation in the event of a Pacific DC Intertie bipolar outage. In contrast, the Intermountain Power Project dc bipolar outage case showed no instability, and hence, no beneficial control function was identified for SMES in this case. Similarly, the contingency at Table Mountain modeled in Case HS10 was stable with no generator dropping, resulting in no identifiable stability benefit for SMES under the conditions evaluated.

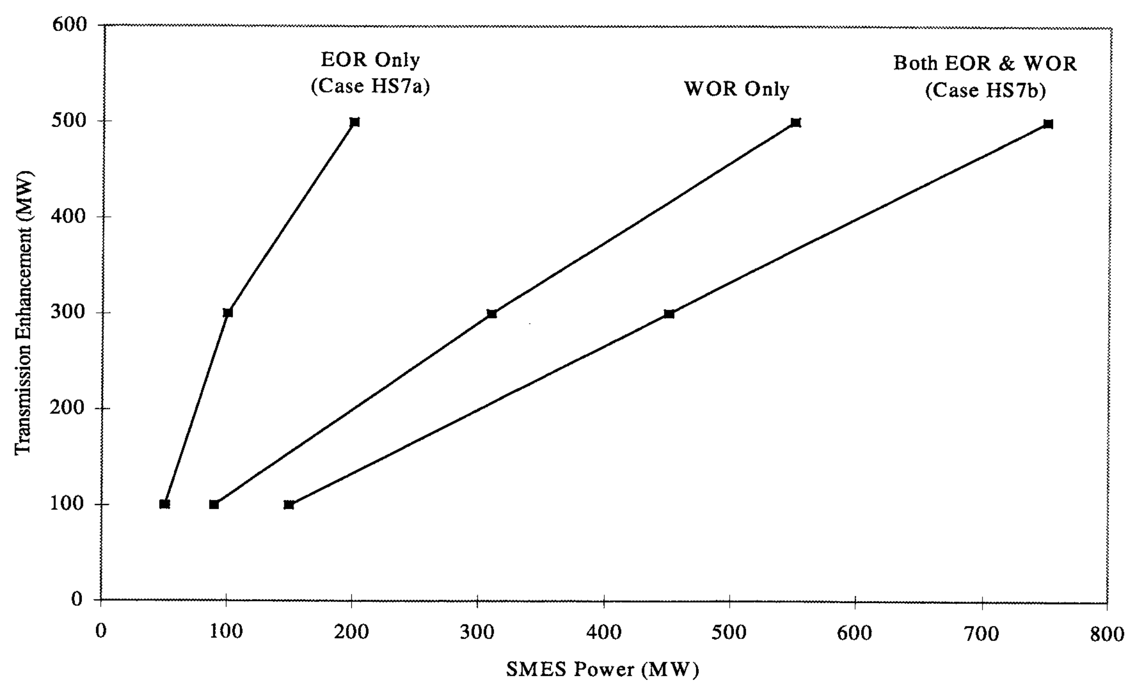

Figure S-1
Transmission enhancement with SMES located at Lugo.

A secondary objective of the study was to compare the value of SMES benefits and costs with those of an alternative control approach. An evaluation of WOR loading increases provided by real- and reactive-power modulation at Devers enabled a simple net present value (NPV) comparison of SMES and static-var compensation (SVC). NPV was estimated as the difference between the present values of their respective benefits and capital costs. The transmission enhancement benefit was valued at $10,000/MW-year. SMES capital costs were derived using EPRI's nth-of-a-kind cost formulation reflecting the minimum SMES power and energy storage capacity needed in each application.

The benefits of SMES providing real-power modulation for transmission stability control exceed the capital cost above 100-MW enhancement, shown in Table S-2. For the same stability enhancement, however, reactive-power modulation, which could be provided by SVC, was found to exhibit similar or in some cases even better control leverage than the real-power modulation derived from SMES. With SVC available at a cost between $40/kVAR and $100/kVAR, the comparison of control effectiveness showed that SVC would have a significantly higher NPV than SMES in enabling transmission enhancement in most of the cases considered. At the 500-MW enhancement, SVC breakeven costs were found to be near $94/kVAR, indicating that SMES could become cost-effective when compared with the upper-range of SVC cost estimates.

These single-benefit comparisons should not be taken at face value to diminish the potential importance of SMES as a future utility energy storage and control device. Other SMES studies show that present values of benefits generally exceed costs only when multiple SMES benefits are enabled by a single device application. It is likely that an evaluation of other SMES-enabled benefits at the locations studied in this project would show SMES to be more attractive and cost-competitive than the above comparisons indicate.

Table S-2
SMES Benefits and Costs at Devers

Transmission Enhancement (MW)	Benefit Present Value ($M)	SMES Modulation		SVC Breakeven Cost ($/kVAR)
		Capital Cost ($M)	Net Present Value ($M)	
100	13.8	18.5	-4.7	230.6
300	41.3	30.1	11.2	120.2
500	68.8	42.4	26.5	94.1

The above results are based on only one model of the future power system (a 1999 heavy summer case), which does not fully explore the potential of using SMES for stability control. A principal recommendation is that different models and loading conditions be evaluated with corresponding limiting contingencies to gain a more complete picture regarding control capabilities afforded by SMES. In addition, advanced stability control techniques, which may take advantage of simultaneous real- and reactive-power modulation, should be studied in detail. Future studies that may influence utility investment decisions should include all site- and situation-specific benefits of SMES and alternative control approaches to establish the overall least-cost or most valuable control option available.

1

INTRODUCTION

This report describes a feasibility scoping study that assesses the ability of superconducting magnetic energy storage (SMES) to improve the stability and power transfer of selected transmission lines in the western North American power system. The study was performed by Battelle Northwest (BNW) for the Electric Power Research Institute (EPRI) with the participation of planners from five west coast utilities. These utilities were known, for the purpose of this study, as the West Coast Utility Group (WCUG). The group consisted of Bonneville Power Administration (BPA), Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E) and Southern California Edison (SCE).

Background

SMES has the potential for performing a broad range of electric utility functions ranging from improving end use power quality to deferring the acquisition of thermal generating units, such as combustion turbines, used to supply peaking power. Power and energy storage requirements vary over several orders of magnitude depending on the function SMES performs. While only a few megajoules (MJ) of energy are sufficient for power quality applications, storage capacity of 100 megawatt hours (MWh) or more may be applicable in load-leveling cases. BPA was the first utility to demonstrate that SMES can successfully interface with a large electrical power network and provide a versatile and responsive device for transmission system testing and control. An experimental 10-MW, 30-MJ (8.3-kWh) SMES device was energized in 1983 at the BPA substation in Tacoma, Washington. Modulation tests indicated that a 10-MW unit at this location would be adequate for damping spontaneous ac intertie oscillations (Hauer and Boenig 1987). The majority of SMES studies performed recently have focussed on generation benefits. Beyond the Tacoma experiment and work reported by Mitani et al. (1988), less attention has been focussed on the transmission applications of SMES.

With the ability to provide real- or reactive-power modulation, SMES is an addition to the array of flexible ac transmission system (FACTS) devices available for transmission enhancement. The prospect of a SMES unit with a rating of several hundred megawatts for few seconds being able to control stability and enhance the power transfer capacity of major transmission corridors aroused the interest of the WCUG, and was the principal motivation for this study.

Study Objectives, Scope and Approach

The overall objectives of this study were to identify and evaluate potential benefits of SMES application scenarios that could enhance the capabilities and operations of utility systems in the western region of the North American power system. The primary focus of this project was on the potential of SMES to: 1) increase the power transfer capacity and reliability of the interties in the region and 2) benefit transmission operations and planning of systems owned by the WCUG. The scope of the analyses focussed on 11 system contingency scenarios (5 base cases and 6 sensitivity cases) defined by the WCUG as being of specific interest when loads increase to levels expected early in the next century.

While transmission stability can be enhanced by modulating real power, reactive power or both to compensate system transients, this study focuses on modulating the real power of SMES to enhance stability in the Southwest United States. The benefit of the stability enhancement is quantified by studying the relationship between SMES sizing and added transmission capacity. The approach used in this study was to investigate how SMES modulation can improve the performance of the integrated power system and increase the stability margin and/or power that can be transmitted from Arizona to Southern California.

Report Organization

The balance of this report consists of five sections and two appendices. Section 2 describes the potential transmission benefits, analytical methodology and bases for estimating specific benefit values. Section 3 contains the analytical results, and Section 4 the comparison of SMES benefits and costs. Section 5 presents the conclusions and recommendations of the study. These sections are followed by the references in Section 6 and appendices containing stability graphs.

2

QUANTIFYING SMES BENEFITS

Under certain circumstances, SMES can enhance transmission system stability and enable increased power transfer over existing transmission corridors, if the unit is properly designed and located to provide control of critical paths in the event of a limiting contingency. In this study, the transmission stability control and enhancement potential of SMES was analyzed using the Extended Transient/Midterm Stability Package (ETMSP), developed by EPRI. This section describes the analytical methodology and bases for estimating specific benefit values presented in following sections of the report.

Study Case Description

The interconnected power system in the western U.S. and Canada, designated as the Western Systems Coordinating Council (WSCC), consists of 66 electrical utility systems and agencies covering all or part of 13 western states, the Canadian provinces of Alberta and British Columbia, and part of the Baja California province of Mexico. California imports considerable amounts of power from Arizona and from the Northwest. Because of transient and oscillatory stability, there are limits on the simultaneous transfer of power from these areas into California. Loss of a critical transmission path can result in undamped power oscillations when these lines are heavily loaded with power flowing from Arizona to Southern California.

Figure 2-1 identifies the major transmission lines in Arizona, California and Nevada, and the locations where SMES was evaluated in the study. For heavy power transfers from Arizona to California, one of the critical disturbances that results in electromechanical oscillations is a three-phase fault at the Palo Verde 500-kV bus followed by the loss of the Palo Verde-North Gila 500-kV line. This line is one of the major tie lines between Arizona and Southern California, as shown in Figure 2-1, and is the limiting contingency addressed by the analysis of SMES in this study. In addition, other contingencies, such as loss of principle transmission capability associated with the ac intertie connecting the Northwest to California and outages of the two regional dc transmission facilities, were analyzed to determine potential operational enhancement benefits SMES could provide.

Stability limitations governing the total power imported into Southern California have been found to be strongly dependent on power flows on the East-of-River (EOR) lines and total inertia of generators in the area. These limitations are represented in the Southern California Import Transmission (SCIT) Nomogram, shown in Figure 2-2. This Nomogram is updated periodically to reflect system conditions or changing configurations having an impact on system stability.

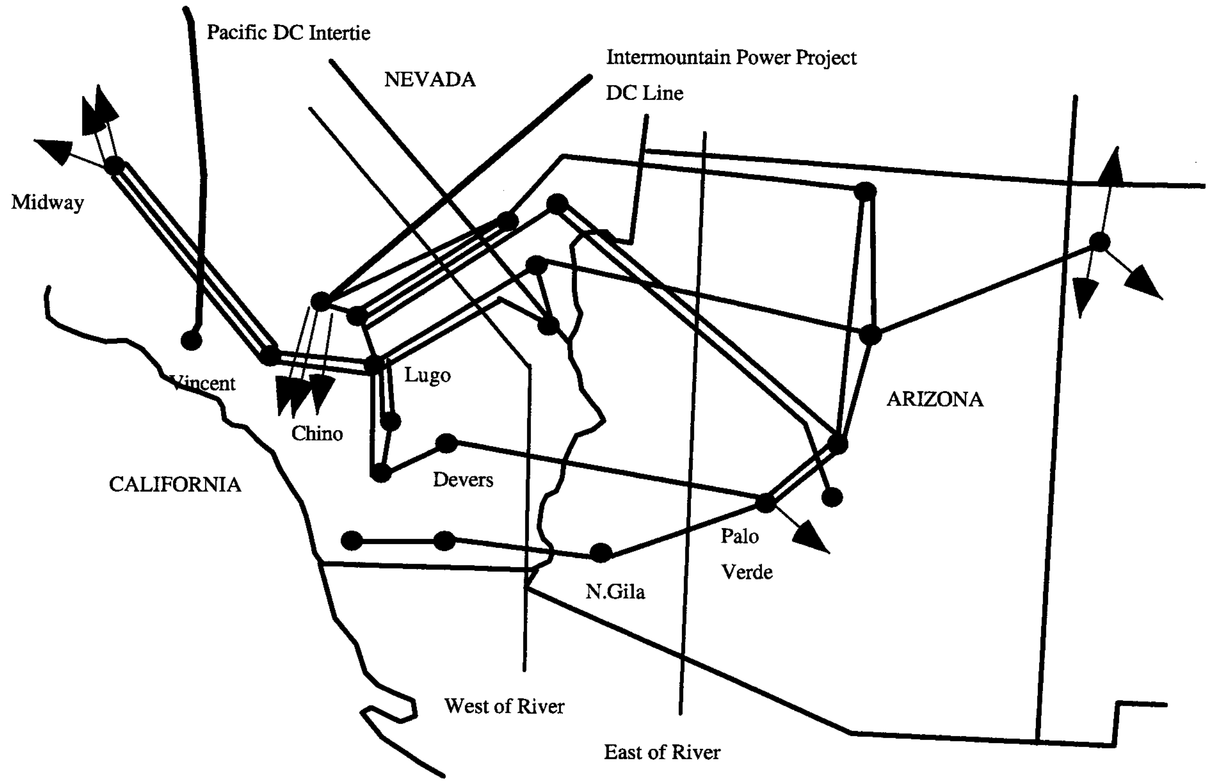

Figure 2-1
General structure of the transmission network in the Southwestern United States.

for the contemporary power system. The non-simultaneous ratings, in this case 16,974 MW for total import and 5700 MW EOR flow, represent the cumulative rated capacity of associated transmission assets. However, system operation must remain within certain stability limits to prevent the possibility of instability, as governed by the Nomogram. At the Nomogram limit, which is also called the simultaneous limit, a marginally-damped response, i.e., a state of persistent oscillation with zero damping, would result from the occurrence of the limiting contingency.

In this study, SMES power modulation was simulated using a full-model representation of the western North American power system. Developed by WSCC member utilities, this model describes a system of 5120 buses, 7456 lines, 2315 transformers, and 944 synchronous machines representing the interconnected power system of the Western United States. The generation resources, loads, transmission infrastructure, and generator characteristics are consistent with projected 1999 conditions. The model used in the study, representing relatively heavily-stressed loadings for key transmission facilities, is referred to as the WSCC 1999 Heavy Summer Model. The Southern California inertia in the 1999 Heavy Summer Model is about 130,000 MW-seconds, well beyond the limit of the current Nomogram. Furthermore, in 1999 the maximum EOR loading will be 7000 MW because the 500-kV Westwing-Mead-Adelanto transmission project, scheduled for commercial operation in December 1995, will add 1300 MW to the EOR capacity.

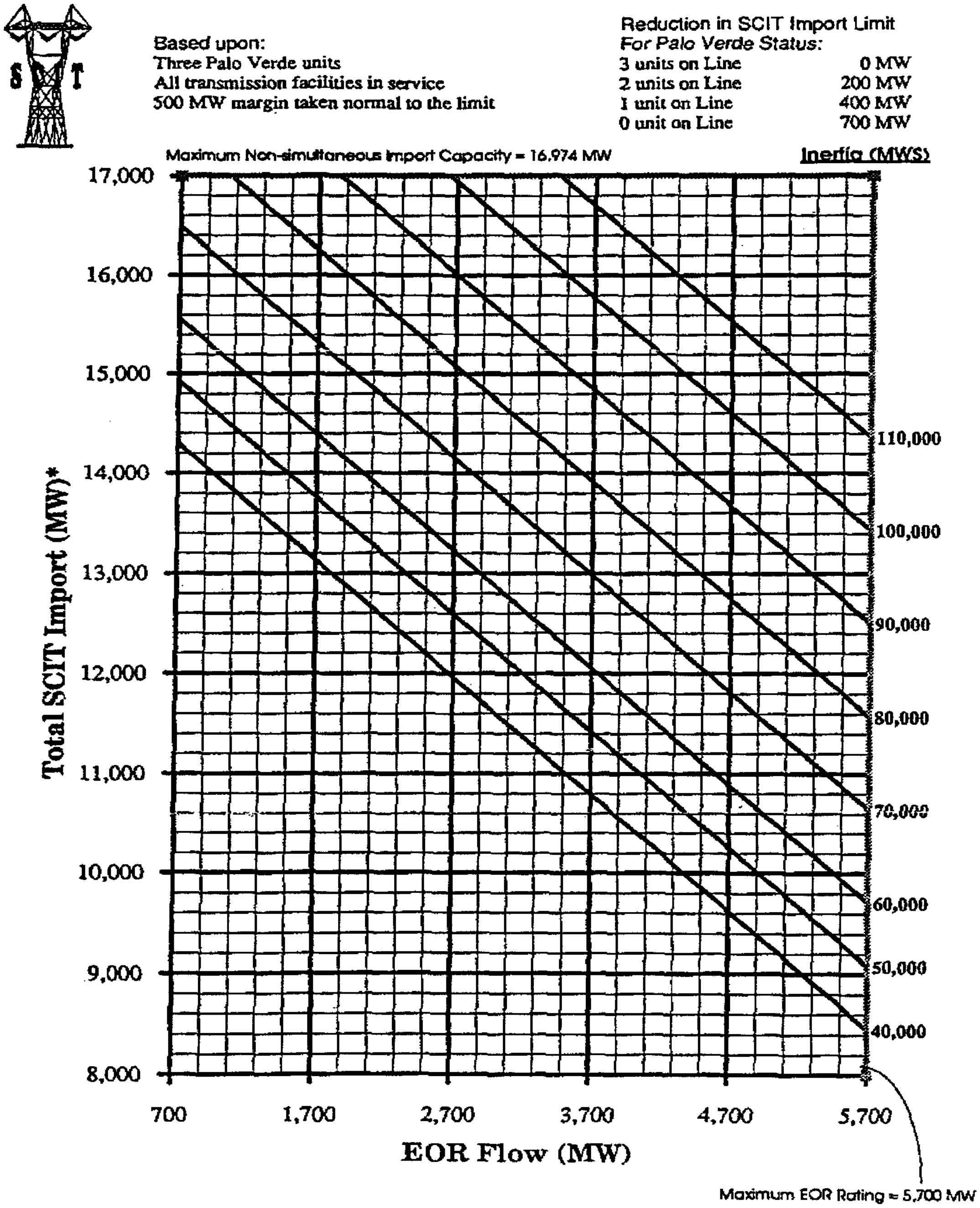

Figure 2-2
Southern California Import Transmission (SCIT) Nomogram

Benchmark Loading Cases

Two cases extrapolated from the 1999 heavy summer model provide the baselines used in the analysis: 1) EOR and West-of-River (WOR) loadings of 7000 MW and 9400 MW, respectively, and 2) EOR loading of 7000 MW with Midway-Vincent lines at 3600 MW. These loading cases are referred to as benchmark cases SCIT-1 and SCIT-2, respectively, and are the bases used in the benchmark analysis described in the following section.

Adjusting area interchanges was the primary method used in the study to control transmission loadings. Selected generators, referred to as stress generators, were adjusted to maintain appropriate loading on the area's so-called "slack" generators. These are generators controlled to maintain the desired area interchange in the power flow solution. When stress generators in the Los Angeles (LA) Basin are adjusted, all stress generators in a given area are adjusted together such that their loading is a common fraction of their nameplate capacity. The loadings on the area slack generators are checked to ensure that they fall within acceptable limits. Because all generation in the Arizona area is already at 100% in the 1999 Heavy Summer Model, load in the area was reduced to achieve the 7000-MW EOR objective.

After the initial transfer objectives were obtained, the next step was to increase the remaining transmission loadings incrementally until an unstable response was observed for the Palo Verde-North Gila line outage contingency. This is an iterative process in which multiple ETMSP simulations are performed to find the loading that results in a marginally-damped response. The marginally-damped response case is defined as the loading case that is 50 MW less than the unstable case, discovered as loadings are increased. The marginally-damped response was determined for both SCIT benchmark cases.

Working Case Set

A study plan was developed and recommended by WCUG representatives to determine the transmission enhancement provided by SMES modulation. The plan involved evaluation of a working case set consisting of five benchmark cases and six sensitivity cases, as indicated in Table 2-1.

In the benchmark cases, HS1 through HS5, the objective of the analyses was to assess baseline system response without SMES for each of the given contingencies. Cases HS1 and HS2 evaluated the system response under loading conditions defined by SCIT-1 and SCIT-2, respectively. These cases provide the bases for establishing the marginally-damped response to the Palo Verde-North Gila line outage contingency. This contingency is defined as a three-phase fault at Palo Verde for four cycles, with the Palo Verde-North Gila line removed when the fault is cleared. A primary concern is the system's characteristic east-west mode of electromechanical oscillation between Southern California and Arizona resulting from this disturbance. Case HS3 investigated the system response to a bipolar outage of the Pacific DC Intertie (PDCI) using the SCIT-2 load case. This scenario addresses the north-south oscillatory mode and the remedial

Table 2-1
Working Case Set

a) Benchmark Loading Conditions

Case	WCUG Recommended Baseline Loadings
SCIT-1	EOR = 7000 MW; WOR = 9400 MW
SCIT-2	EOR = 7000 MW; Midway-Vincent = 3600 MW

b) Benchmark Cases

Case	Loading	Modeled Contingency
HS1	SCIT-1	3ϕ fault @ Palo Verde, loss of Palo Verde-North Gila line
HS2	SCIT-2	3ϕ fault @ Palo Verde, loss of Palo Verde-North Gila line
HS3	SCIT-2	Pacific DC Intertie (PDCI) bipole outage[a]
HS4	SCIT-1	Intermountain Power Project (IPP) DC bipole outage[a]
HS5	SCIT-2	3ϕ fault @ Table Mountain, loss of Table Mountain-Tesla, Table Mountain-Vaca Dixon lines[a]

(a) Switching sequences defined in 1994 Pacific and Southwest Transfer (PAST) Subcommittee Handbook (Mackin et al. 1994).

c) Sensitivity Cases

Case	Benchmark	SMES Control Objective
HS6	HS1	Increase WOR loading by 500 MW
HS7a	HS2	Increase EOR loading by 500 MW
HS7b	HS2	Increase EOR and WOR loading by 500 MW
HS8	HS3	Reduce remedial action generator dropping
HS9	HS4	Reduce remedial action generator dropping
HS10	HS5	Reduce remedial action generator dropping

action switching sequence defined in the Pacific and Southwest Transfer (PAST) Subcommittee Handbook. Case HS4 is similar to HS3 but was based on SCIT-1 and the contingency of an Intermountain Power Project (IPP) DC bipolar outage. The final benchmark case, HS5, investigated the system response with SCIT-2 loading following a three-phase fault at Table Mountain and loss of Table Mountain-Tesla and Table Mountain-Vaca Dixon lines. Similar to the previous two contingencies, the primary concern was evaluating operation of the remedial action switching sequences.

All of the sensitivity cases evaluated the potential benefits of using SMES to enable increased power transfer or to reduce the need for generator dropping in the remedial action sequence. In cases HS6 and HS7a, the SMES control objective was to increase WOR and EOR transmission by 500 MW above levels determined in HS1 and HS2. Cases HS8, HS9 and HS10 investigated the ability of SMES to reduce the amount of generator dropping necessary to control the system response established in HS3, HS4, and HS5, respectively.

The working case set originally involved five sensitivity cases (HS6, HS7a, HS8, HS9 and HS10). While independent increases in EOR and WOR loadings could be used to determine the SMES-enabled increase in the range of the SCIT Nomogram, a simultaneous increase in EOR and WOR loading is a more realistic scenario for increasing imports into Southern California. Because there is generally a fixed amount of generation resources available in the Southern Nevada area, EOR and WOR flows are tightly coupled with each other. For this reason, the WCUG advisors requested another case be added to the working case set, designated HS7b, to evaluate the ability of SMES to provide a simultaneous 500-MW increase in both EOR and WOR transmission capacity.

Another aspect of determining stability enhancement afforded by the addition of SMES to increase the amount of Southern California imports concerns the fact that a 7000-MW loading on the EOR corridor is the maximum non-simultaneous loading. Therefore, any additional capacity beyond the 7000-MW loading (i.e., as enabled by SMES) would require additional investment to increase the ratings of the transmission lines associated with the EOR corridor. This enhancement could be achieved with upgrading series compensation and possibly substation equipment, but would represent costs in addition to the SMES facility. Therefore, when evaluating stability enhancement, only increases in WOR transfer capacity can be attributed solely to SMES.

Other Cases

In addition to the above cases recommended by the WCUG, other cases were assessed that addressed issues and interests raised during the course of the study. The first of these was a sensitivity case to determine if SMES modulation control at Lugo could provide transmission loading enhancement for the Palo Verde-Devers line outage contingency. This disturbance, a three-phase fault at the Palo Verde 500-kV bus followed by the loss of the Palo Verde-Devers 500-kV line, is similar to the Palo Verde-North Gila line outage contingency in importance for determining Southern California import limits.

When establishing the maximum imports available, a stability margin is generally included to provide a safety margin between the planning results and operational limits. For example, the SCIT Nomogram in Figure 2-2 includes a 500-MW stability margin, meaning that the simulations used to construct the Nomogram had marginally-damped loadings 500 MW beyond the limits shown by the Nomogram. The WCUG advisors requested that an additional case be added to take this stability margin into account to evaluate the improved damping provided by SMES under these conditions.

Three cases were developed to compare control leverage (ratio of enabled increase in transmission loading to control power), benefits and costs of SMES with those of alternative approaches. During analysis of case HS6, evidence of an imminent voltage collapse suggested an opportunity to compare SMES and capacitors as alternative control solutions. The modulation of both real and reactive power was simulated at Chino under conditions represented in case HS7b to determine if either approach possessed an advantage enhancing the power transfer capability of the transmission system. Finally, to satisfy the objective of making an economic comparison, the control leverage provided by real-power modulation from SMES was compared with that of reactive-power modulation provided by static-var compensation (SVC). This comparison estimated control leverage of the alternatives located at Devers to provide a range of WOR transmission enhancement between 100 MW and 500 MW.

SMES Model

To fully model SMES, the converters and their controls should be modeled in detail. For the purposes of a scoping study, however, a relatively simple analysis that uses real- or reactive-power injection is all that is necessary to evaluate SMES stability-enhancement benefits. The assumptions are made that the converters themselves are responsive to changes in power provided by the modulation controls, and deviations from the ideal response are negligible compared to the resolution the study is intended to provide.

The SMES power converter was assumed to use a forced-commutated, gate turn-off devices for transforming the dc power stored in the SMES coil to ac power exchanged with the grid. This power conditioning system has the ability to provide four-quadrant power transfer, i.e., the ability to inject or withdraw both real or reactive power. Also, because force-commutated conversion is used, the power injection is independent of the ac voltage.

Stability enhancement could be provided by SMES modulating real or reactive power to damp electromechanical modes associated with stability-limited transmission corridors. Reactive-power modulation, using static-var compensation, has long been a method for enhancing transmission capacity in power systems. Thus, to provide a basis for comparison with SVC, this study focussed on the ability of SMES to deliver real-power modulation as a means of enhancing transmission capacity. In actuality, SMES could provide the simultaneous modulation of real and reactive power. To determine the (potentially greater) benefits of such operation would require additional studies beyond the scope of this project.

The SMES model developed for this study uses a feature of ETMSP that allows sophisticated FACTS control devices to be analyzed in transmission stability planning models. These devices have a variety of attributes, the most important of which is a flexible means by which different controller designs can be developed. User-defined models enable the user to build a controller from a library of basic building blocks. These building blocks are constructed to provide the desired control function of the device, culminating in the actual interface to the network through a set of available end-blocks.

The function of SMES analyzed in this study requires the injection of real power to provide modulation. No device-specific end-block was available in ETMSP to model this interaction with the network. The closest module approximating SMES real-power injection was that of a resistive brake, which was modified to change the nature of the current injection from constant impedance to constant power. Next, the limit constraining the device to exhibit only positive impedance was removed, allowing the new device to both inject and withdraw power from the network, both independent of the voltage. This module also has the provision of providing bi-directional reactive-power injection independent of voltage. Extensive testing of ETMSP was performed to ensure that the modified brake module provided a satisfactory representation of SMES interaction with the network.

SMES Control Design Philosophy

The ETMSP user-defined model has a variety of input signals available from which to build the necessary feedback control circuit. These signals include bus voltage magnitude and angle, line real and reactive power, line current, as well as auxiliary signals such as simulation time.

Feedback through a compensating controller is used to modulate SMES real or reactive power. The design approach for the controller is based on advanced, but well established, small-signal stability control methodologies described in the literature; a recent review is given by Kundur (1994). An overview of the design approach is described here; for a more detailed understanding, one should consult the references cited in this section. Primarily, three steps are required: 1) select a location for the SMES unit; 2) choose feedback signals; and 3) select the compensating parameters. Step 1 is accomplished by studying the controllability of the primary mode of oscillation resulting from the disturbance with real- and reactive-power injections at different buses. Similarly, step 2 is addressed by investigating the observability of the primary mode in signals that may be used for feedback. The objective of these two steps is to place SMES at a bus where it will have the largest impact on the mode (i.e., maximum controllability) and also where a feedback signal contains a strong signature of the modal oscillations (i.e., high observability). Classical design techniques are used to select controller parameters that provide proper phasing and gain at the modulation frequency.

Steps 1 and 2 of the control design require a detailed understanding of the system's modal behavior. Modal analysis is a methodology for measuring modal frequency, damping, gain, and phase, and is the primary tool used to investigate system oscillations. The gain and phase characteristics govern the modal controllability and observability. A number of parameters are available for measuring such characteristics including eigenvectors, participation factors, and residues; all of which are mathematically related (Kundur 1994). For real- or reactive-power injection at a non-generator bus, the transfer function residue is used to study controllability and observability (Pagola et al. 1988). In comparing controllability of different injection buses, the residue is calculated from each bus to a given output signal. The larger the residue, the more controllable the mode is by power injection at that bus. Similarly, to compare observability of different feedback signals for a given injection bus, residues are calculated for the bus to each signal. A larger residue implies higher mode observability. To simplify the control structure, only signals available at the chosen injection bus were considered for feedback (such as local voltage magnitude, angle and selected nearby line parameters). Other signals were evaluated (such as phase-angle differences between buses), but were generally not used. Locally-derived input signals were found which had enough observability to design a modulator.

In this study, eigenanalysis and Prony analysis tools were used for conducting modal analysis. Eigenanalysis is described in detail in Kundur (1994), and is the approach used in the Small Signal Stability Package (SSSP) developed by EPRI. Prony analysis is a technique of analyzing signals to determine modal, damping, phase, and magnitude information contained in the signal (Hauer et al. 1990) and is the basis for computer codes being developed by Battelle Northwest (Trudnowski 1994). For bus power injection, the version of SSSP used in this study did not provide an option for calculating the required residues. Also, because the post-fault system was often near instability, it was difficult to obtain an accurate power flow solution, which SSSP requires. For these reasons, modal analysis conducted in this study depended heavily on Prony analysis.

To conduct Prony analysis for a given case, a small power injection pulse is placed into the bus and the system response is simulated using ETMSP. The system's response is then analyzed using Prony resulting in the required modal information. This approach is described by Trudnowski et al. (1991). When possible, care was taken to benchmark and validate Prony results with SSSP analysis. Once the injection bus and feedback signal are identified, the parameters of the compensating controller are determined. Frequency response and transfer-function identification based on Prony analysis are used to characterize the system from injection to output signal. Classical control techniques (e.g., root locus and frequency response analysis) were used to determine the proper feedback parameter settings. Control parameters are chosen to provide maximum damping to the principal oscillatory mode and to minimize any negative impact on other modes. Also, controllers were required to have a minimum 3dB gain margin.

A block diagram of the controller is given in Figure 2-3. The controller includes a washout filter (time-constant T_W), a low-pass filter (time-constant T_L), and in some instances, a compensator block to provide additional lead or lag to the feedback control (time constants T_1 and T_2). Filter time constants are used to avoid control interactions outside the desired bandwidth. The compensator block parameters are used to provide the desired phasing. However, in most cases, sufficient control of the phasing could be obtained by proper placement of the washout or low-pass filter poles.

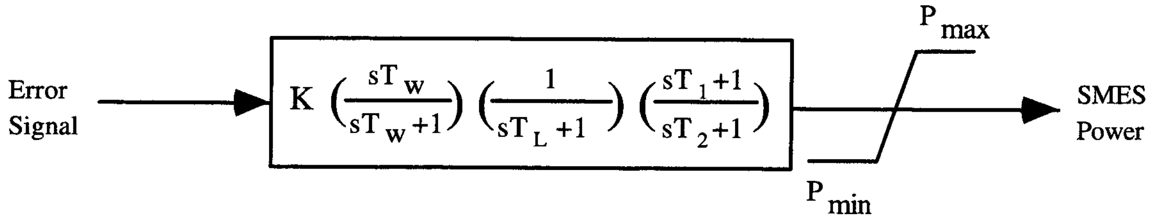

Figure 2-3
Modulation control block diagram.

3

ANALYTICAL RESULTS

This section summarizes the results of analyses conducted on the cases identified in Section 2.

Benchmark Loading Conditions

Following the procedures outlined in Section 2, loading conditions were determined that exhibit a marginally-damped response to the Palo Verde-North Gila line outage contingency. The SCIT-1 benchmark case involved loading the EOR and WOR transmission corridors to 7000 MW and 9400 MW, respectively, and increasing the Midway-Vincent loading until a marginally-damped response was observed. This was determined by increasing the Midway-Vincent loading incrementally until an unstable response to the contingency occurred. At this point, the Midway-Vincent loading that was 50 MW less than the unstable loading condition was defined and confirmed as the marginally-stable case. Likewise, the SCIT-2 benchmark was determined by first loading the EOR and Midway-Vincent lines to 7000 MW and 3600 MW, respectively, and then increasing the WOR loading until a marginally-damped response to the Palo Verde-North Gila line outage contingency occurred. These results are shown in Table 3-1. Transmission line loadings in a power flow solution are derived quantities, not explicitly based on input parameters. Therefore, actual transmission loadings can deviate up to 3% from the specified targets.

Voltage magnitude swings at Devers, a good indication of system stability in response to this contingency, are shown in Figures 3-1 and 3-2 for both the SCIT-1 and SCIT-2 benchmark cases. Also shown for each is 50 MW additional loading, demonstrating that the benchmark cases are at the threshold of instability. More complete system responses are given in Appendices A and B for the SCIT-1 and SCIT-2 benchmark loading conditions, respectively.

Table 3-1
Marginally-Damped Loading Conditions

Transmission Corridor	SCIT-1 Benchmark (MW)	SCIT-2 Benchmark (MW)
East-of-River (EOR)	7020	7007
West-of-River (WOR)	9414	8536
Midway-Vincent	1967	3611

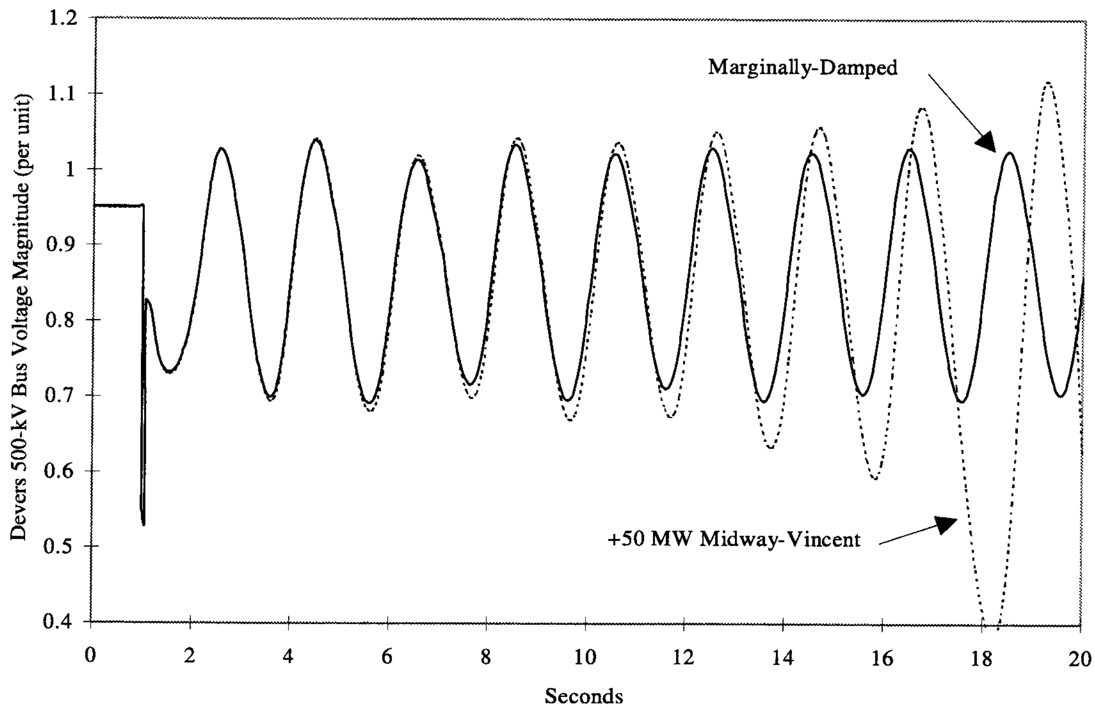

Figure 3-1
Palo Verde-North Gila contingency for SCIT-1 benchmark case.

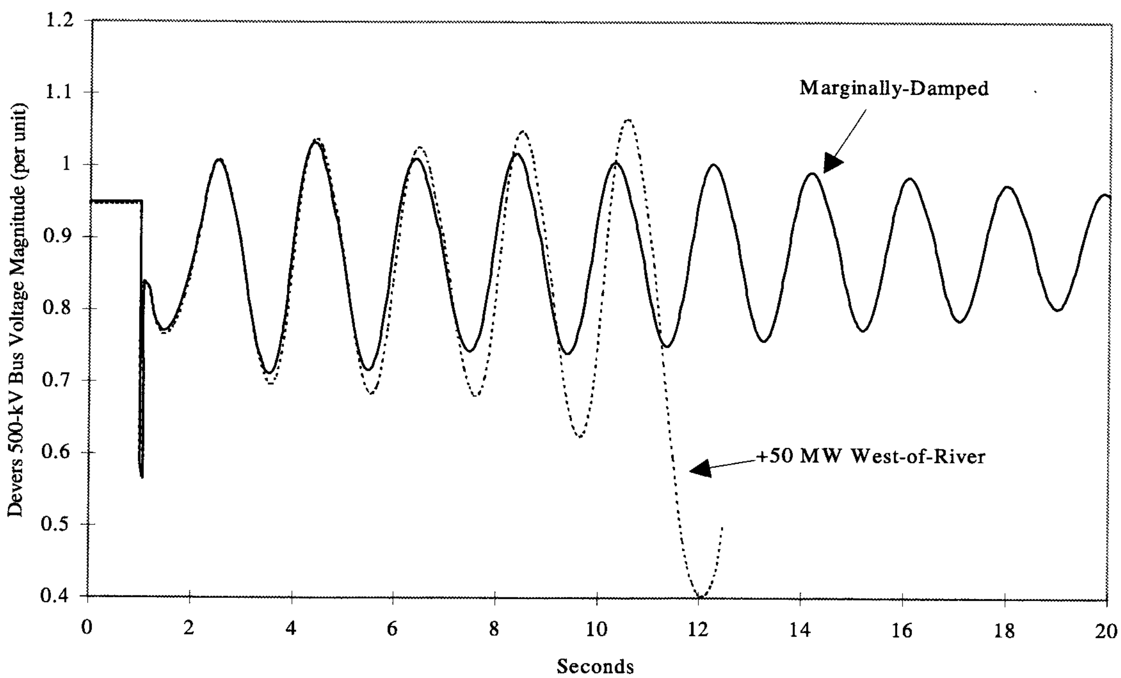

Figure 3-2
Palo Verde-North Gila contingency for SCIT-2 benchmark case.

The marginally-damped case exhibits a strong 0.5-Hz mode in response to the Palo Verde-North Gila line outage contingency. Detailed simulation and modal analysis revealed that for this mode, machines in the LA Basin oscillate against those in the Arizona area. As expected, the oscillations are strongly observable in real-power flows and bus voltage angles. Also, 0.5-Hz swings occur heavily in the reactive line flows and bus voltage magnitudes. This mode appears to be very similar to the 0.67-Hz oscillatory mode present in the contemporary power system (Lee et al. 1994). Under heavier loading conditions and higher inertia, the frequency is somewhat less in the 1999 Heavy Summer Model. Analysis showed that the mode damping is sensitive to the status of the Palo Verde-North Gila line, but mode shape remains relatively constant. A second dominant mode is observed at about 0.25 Hz, and is predominately a north-south mode in which Arizona and Southern California oscillate in phase with each other.

Two Palo Verde-Devers Lines (HS6)

The first sensitivity scenario of the working case set increases the WOR loading by 500 MW over the marginally-damped loading conditions defined by the Palo Verde-North Gila line outage contingency. This case was studied with two Palo Verde-Devers lines in place, although only one exists at present. The second Palo Verde-Devers line, currently in the planning process, is contained in the original 1999 heavy summer model provided by the WCUG. During the course of the project, WCUG utility planners expressed the opinion that this line probably would not be constructed before the end of the century, and should be taken out of the model. Because the analysis for case HS6 was completed before this guidance was received, it was agreed to keep this line as part of HS6 but to remove it in all the other analyses. The marginally-damped loading conditions shown in Table 3-2 were used only in conjunction with case HS6. All other cases used the SCIT benchmark loading conditions given in Table 3-1.

The loading of WOR lines was increased by 500 MW and SMES control was used to achieve a stable case under loading conditions that would otherwise be unstable. However, because all of the generation is at or near maximum capacity in the Las Vegas area, a total of 10 loads in this area over 100 MW were reduced by 50 MW each to obtain the additional 500-MW loading of the WOR transmission corridor.

Table 3-2
SCIT-1 Benchmark Loading Conditions with Two Palo Verde-Devers Lines

Transmission Corridor	Benchmark Loading (MW)
East-of-River (EOR)	7026
West-of-River (WOR)	9405
Midway-Vincent	2869

The first step in the analysis was to explore the characteristics of the disturbance to identify the mode shape of the oscillatory instability that would be controlled by the SMES unit. The 0.5-Hz mode, which has negative damping in response to the Palo Verde-North Gila line outage, is a predominantly east-west mode, with the Arizona area oscillating against the LA Basin. Candidate locations were screened for relative control leverage by analyzing the system response to a small power pulse injected at the bus, as described in Section 2. Each end of the Palo Verde-Devers lines were analyzed, and it was found that the mode would not be observed very well in any of the locally available signals. These signals include bus voltage magnitude and angle (frequency deviation is equivalent to the derivative of the angle), real- and reactive- power flow and current on adjacent lines. An investigation was made for three points (in quarter-length steps) along the Palo Verde-Devers line. The mode was found to be controlled best from a point one-quarter of the way from Palo Verde along these lines. It was here that the SMES unit was located for this case, and a controller was designed.

After confirming that SMES power modulation effectively controlled this case, the next step was to reduce the available SMES power to determine the minimum size necessary to obtain a stable response to the disturbance. A stable response was obtained with SMES reduced to ±250 MW, while a 200-MW unit was too small to prevent an unstable response, as shown in Figure 3-3.

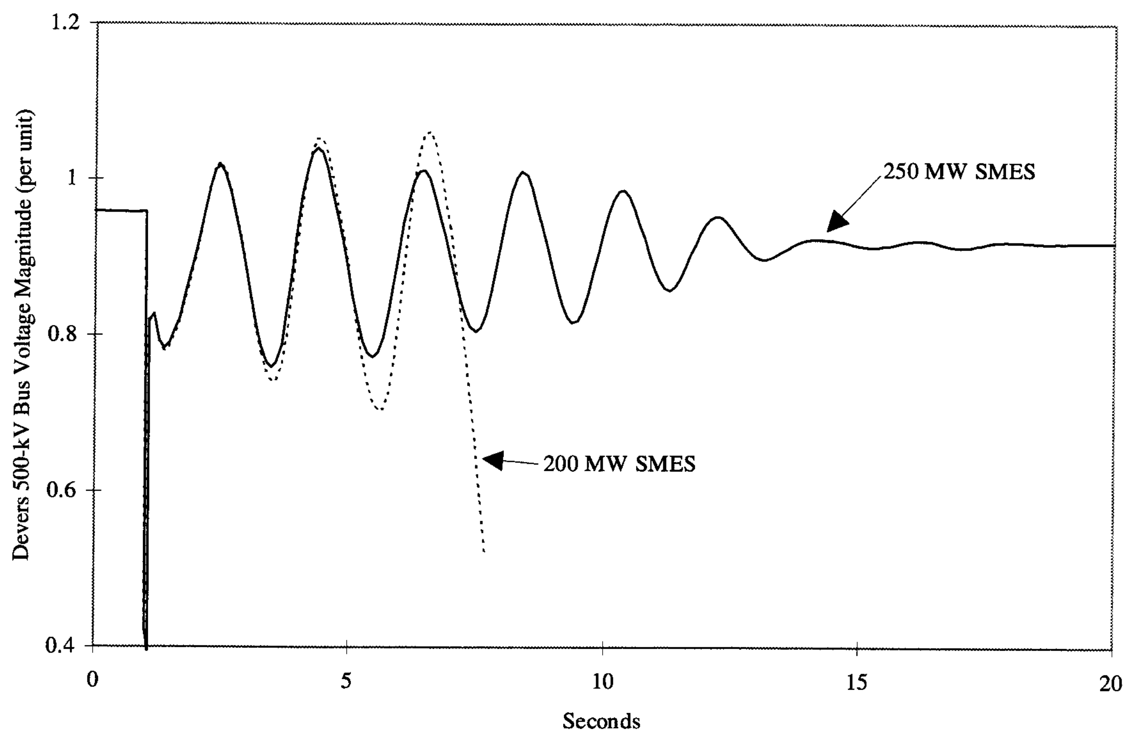

Figure 3-3
Minimum SMES needed for stable response with WOR loading increased 500 MW.

The power and energy responses of the 250-MW SMES device are shown in Figures 3-4 and 3-5. The power plot shows the controller is saturated at the maximum SMES power rating for most of the response duration. The energy plot, an integration of the power response, indicates that a maximum of about 500 MW-seconds (about 140 kWh) is necessary in this case.

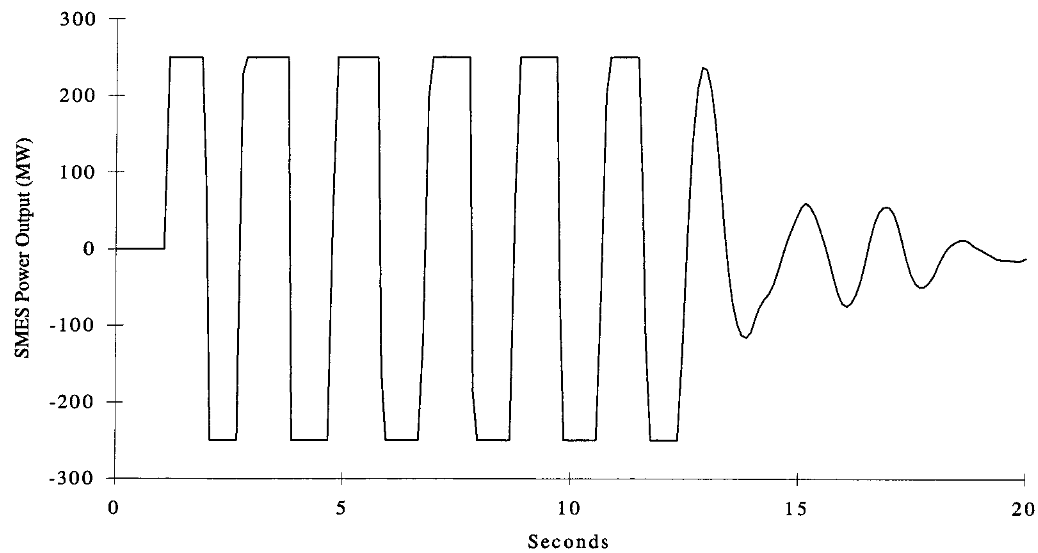

Figure 3-4
SMES power output for case HS6.

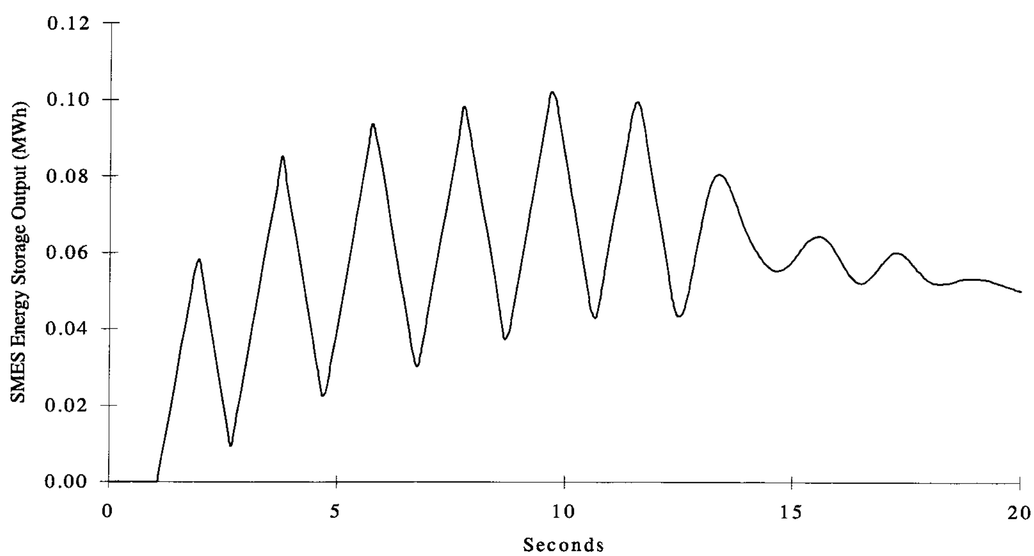

Figure 3-5
SMES energy output for case HS6.

Palo Verde-North Gila Contingency (HS7)

Because it is physically impractical to achieve increases in EOR or WOR loadings independently (based on available generating resources in the region), a more realistic condition worthy of analysis is simultaneous EOR and WOR loading increases. However, because analysis of independent EOR and WOR loading increases is useful for studying impacts on the SCIT Nomogram, it was decided to retain these options. Therefore, the original HS7 study plan was modified to assess the following SMES control objectives:

- increase EOR loading by 500 MW with one Palo Verde-Devers line (case HS7a).

- increase EOR and WOR loadings simultaneously by 500 MW (case HS7b).

Both HS7 cases in the amended study plan involve benchmark EOR loadings of 7500 MW. Because the simultaneous limit of the EOR corridor is 7000 MW, any increase beyond this limit would involve increasing the steady-state power transfer limits of these lines. Upgrading the steady-state transfer limits represents an additional cost beyond that of SMES, i.e., augmenting series compensation equipment to allow higher currents. Therefore, an additional set of runs was performed for case HS7 to analyze increasing WOR loading only. This facilitated the economic analysis of the stability enhancement afforded by SMES, as the additional investment associated with the required thermal upgrade could be neglected.

Case HS7 was further expanded to include evaluating loading increases of 100 MW, 300 MW, and 500 MW for EOR only (HS7a), WOR only, and both EOR and WOR simultaneously (HS7b). To more fully analyze the stability enhancement potential of SMES and evaluate control leverage as a function of transmission stability enhancement, three loading levels provide the minimum set needed to establish a control leverage curve to explore possible saturation.

The nature of the post-disturbance system was quite different from the case when one Palo Verde-Devers line was considered. The case with two lines (HS6) had indications of severe voltage-collapse problems, with insufficient reactive support to maintain voltages for the increased transmission loadings. This problem is alleviated immensely with one Palo Verde-Devers line because the marginally-damped contingency occurs at a much lower line loading with less stress on the remainder of the system. This indicates that much more reactive support is needed in the system than the 1999 Heavy Summer Model contains with two Palo Verde-Devers lines included. A detailed evaluation of this phenomena was beyond the scope of this study.

Several candidate locations were analyzed to determine the optimal placement of SMES. As described in Section 2, relative controllability was evaluated using pulse power injections at candidate buses. Based on these tests, there appears to be little variation in control leverage for real-power modulation across a wide range of locations in the LA Basin. Candidate locations outside the LA Basin, such as Eldorado in the southern Nevada area, were found to exhibit very poor control leverage, and were deemed unsuitable real-power modulation control locations for this application. No significant differences in real-power modulation leverage was observed for several LA Basin buses as, confirmed by a series of simulations for SMES located at Devers, Lugo, and Vincent. However, there are significant differences in reactive-power modulation leverage, which must be taken into account when analyzing options for SVC modulation.

Lugo was selected as the primary SMES location in case HS7. With no major differences observed in real-power modulation control leverage, the primary reason for this selection was the highly interconnected nature of this bus. It has several 500-kV lines connecting it with other major substations in the area. The rationale is that the high degree of interconnection could provide benefits beyond those associated with this case, such as using the same SMES location for controlling other cases (HS8, HS9, or HS10), other contingencies not in the working case set, or for voltage support and automatic generator control functions.

A detailed analysis was performed with SMES located at Lugo for case HS7. The modulation controls were tuned to optimize the SMES response for this location. Case HS7 results are given in Table 3-3 and shown in Figure 3-6, in which the minimum SMES power to achieve a desired transmission capacity increase is determined. Each point in the table (and the associated figure) was determined with a series of simulations with different SMES unit sizes to determine the minimum required for a stable response. For example, Figure 3-7 shows that case HS7a is stable with a 200-MW SMES unit, but unstable when the modulation power is reduced to 150 MW.

The results indicate that the control leverage obtained by SMES is highly dependent on which corridor is being increased beyond the marginally-damped conditions. Increasing the EOR corridor only, while keeping the others constant, can be achieved with much less SMES power

Table 3-3
Case HS7 Results - SMES at Lugo

Transmission Enhancement (MW)	Minimum SMES Modulation Power at Lugo (MW) [a]		
	East-of-River Only	West-of-River Only	Both EOR/WOR
100	50	100	150
300	100	350	450
500	200 (case HS7a)	550	750 (case HS7b)

(a) 50-MW resolution

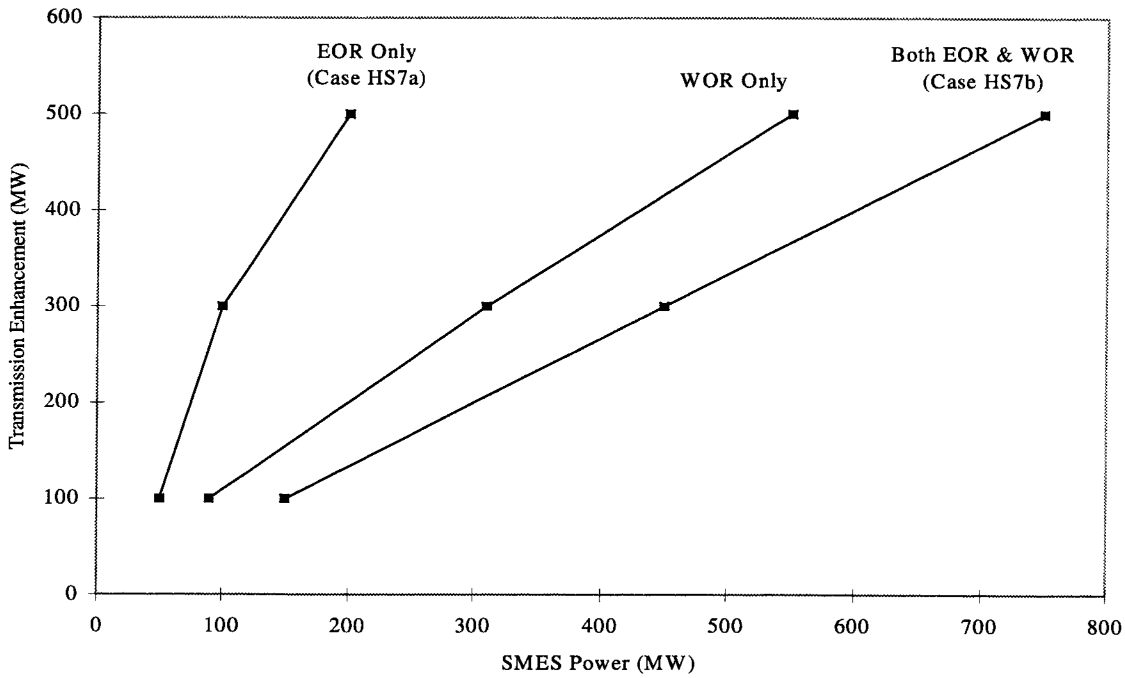

Figure 3-6
Minimum SMES unit size needed to provide transmission enhancement when located at Lugo.

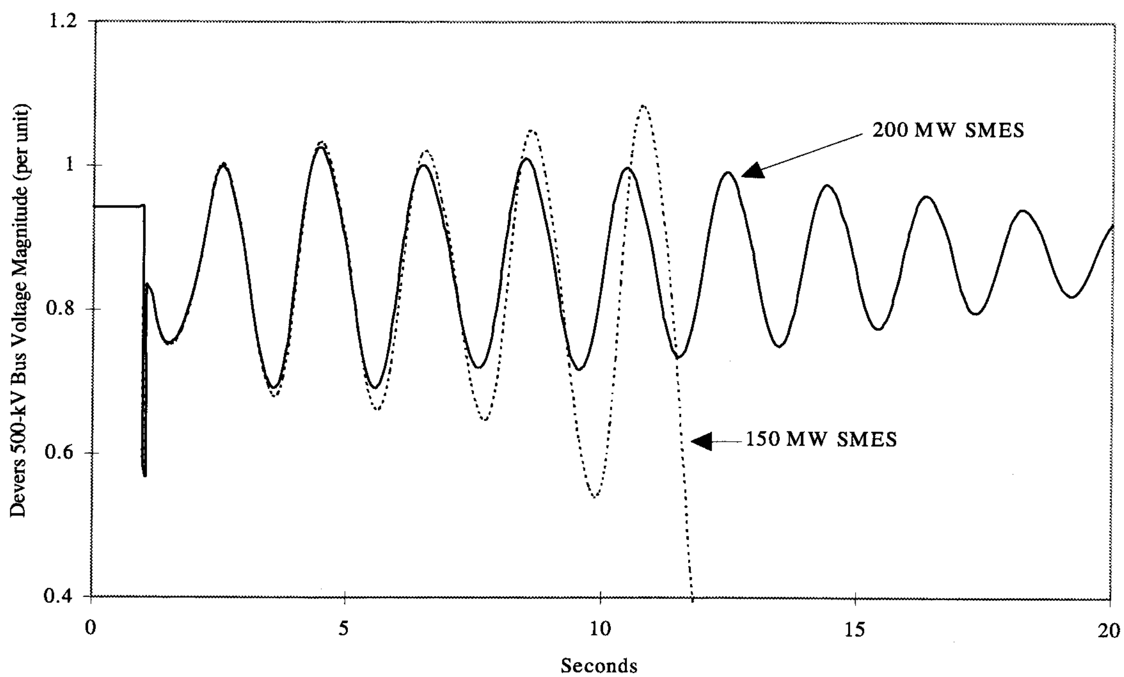

Figure 3-7
Minimum size required to provide a 500-MW EOR increase (HS7a) with a SMES unit applied at Lugo.

than increasing either the WOR corridor or both EOR and WOR simultaneously. Furthermore, these increases are fairly linear, in which the control leverage stays relatively constant through a range of increased transmission loadings.

The minimum SMES energy requirements were determined for case HS7a with SMES at Lugo, which has a 200-MW minimum power requirement. The resulting power and energy profiles of this SMES unit are shown in Figures 3-8 and 3-9, respectively. The minimum SMES energy storage capacity is about 50 kWh for this scenario. The SMES power and energy profiles of the other cases are very similar, with a proportional relationship between energy storage capacity required and the maximum power of the device. This relationship is a function of the modulation frequency. Because the frequency of oscillation is about 0.5 Hz, the approximate energy storage capacity is equivalent to one second of full-power discharge.

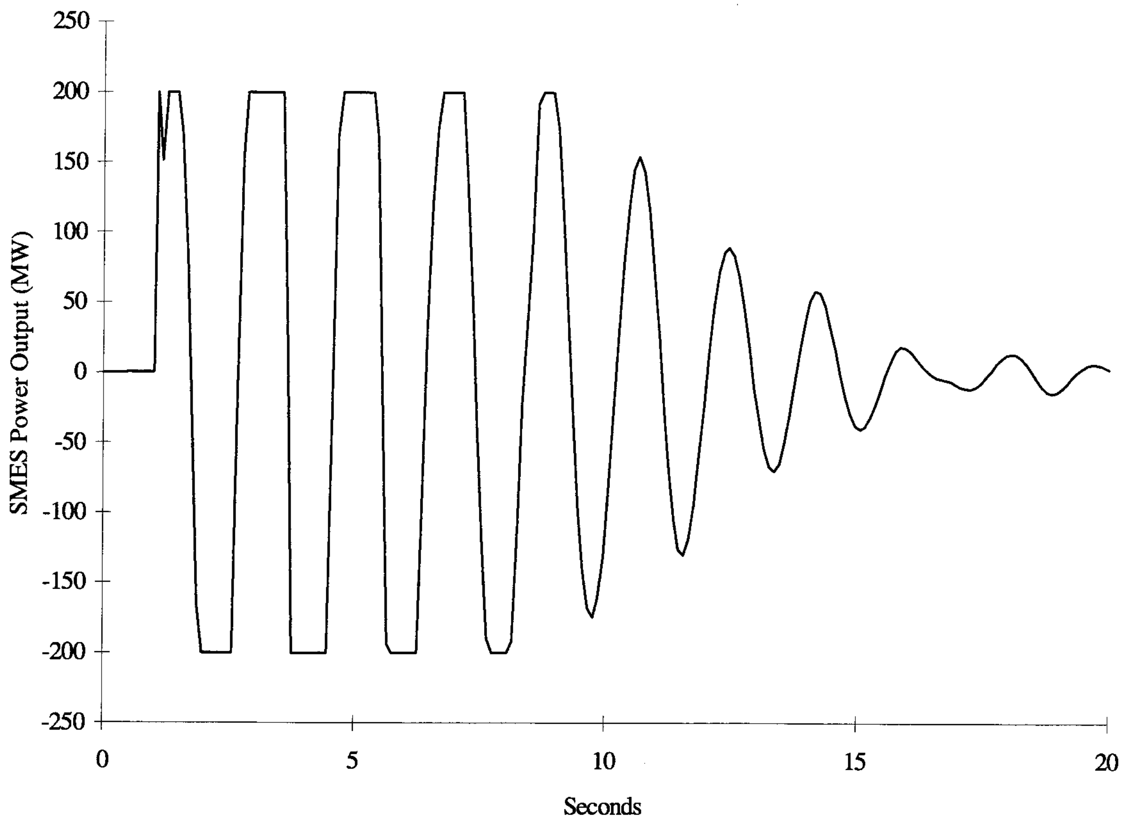

Figure 3-8
SMES power output to provide a 500-MW EOR increase (HS7a) with a 200-MW SMES unit applied at Lugo.

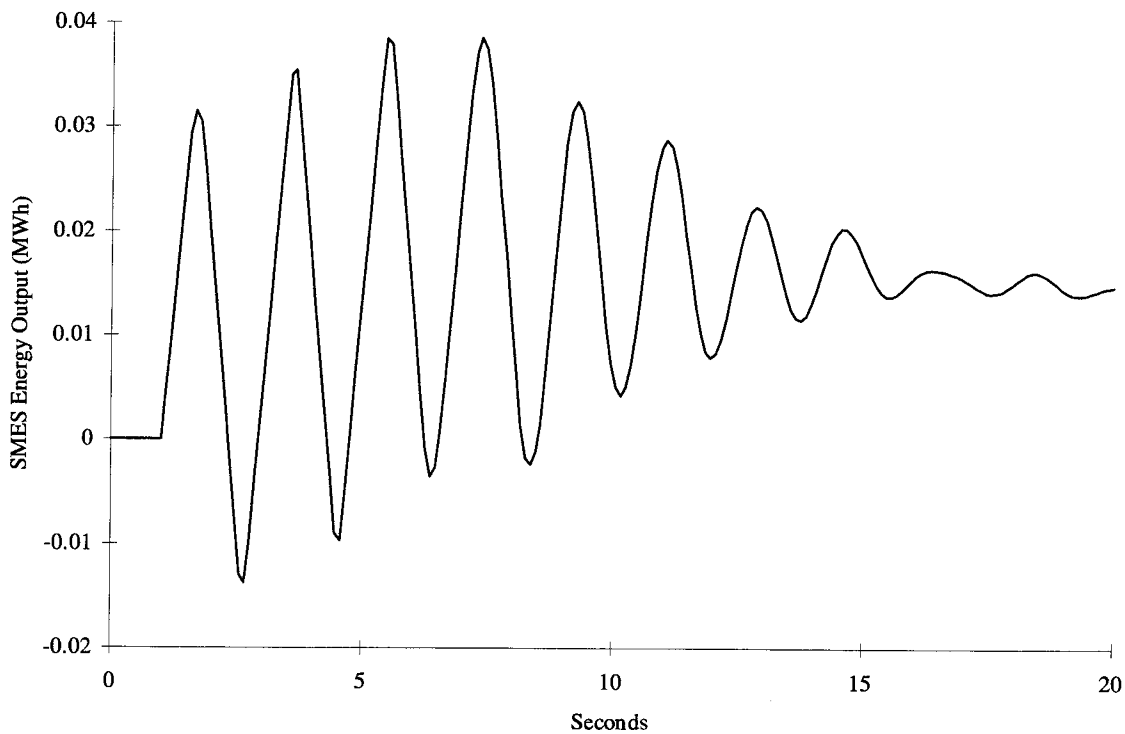

Figure 3-9
SMES energy required to provide a 500-MW EOR increase (HS7a) with a 200-MW SMES unit applied at Lugo.

Pacific DC Intertie Bipolar Outage (HS8)

This case involves simulating the complete loss of the 3100-MW Pacific DC Intertie (PDCI) and evaluating the effectiveness of using SMES to partially offset the remedial action scheme that would be implemented for this disturbance. This remedial action includes dropping generators in the Northwest to minimize the mismatch between load and generation immediately following the disturbance. This action also prevents critical tie lines from overloading and leading to an uncontrolled system separation. The specific sequence of events simulating these remedial actions is provided in the Pacific and Southwest Transfer (PAST) Coordination Subcommittee 1994 Handbook (Mackin et al. 1994).

The system response is quite different from that of the Palo Verde-North Gila scenarios (HS6 and HS7). Insufficient damping of the east-west oscillatory mode is not the crucial limiting factor associated with this disturbance. Rather, the nature of the PDCI contingency requires a steady-state power component to offset the effect of reduced generator dropping. Also, a different oscillation, a 0.63-Hz north-south mode, dominates the system response of this disturbance.

Based on guidance received from the WCUG planners, four control locations were evaluated for this case: Lugo, Devers, Rinaldi and Eldorado. At each of these locations, SMES was simulated to provide constant power after the outage. These results were analyzed using Prony analysis to determine which location provided the most effective insertion point for SMES control. Eldorado required much more SMES power than the other three sites for a similar response, and was not considered further. The other three locations had very similar response characteristics. Because there was less sensitivity between SMES unit size and the damping observed for the 0.63-Hz mode with SMES located at Lugo, this was determined to be the best site for controlling this disturbance. Analysis of SMES power needed to compensate the need for generator dropping was performed, with the results given in Table 3-4.

The sensitivity with respect to location, and the effectiveness of modulation control, were investigated for a case with 700 MW of generator dropping. Several approaches for incorporating modulation were evaluated, none of which provided significantly more control leverage than the step response. A controller was devised and tested that combines a step response with oscillatory damping. Similar control leverage as provided with a step response only was observed. However, this combined control reduces the amount of energy that would be required from a step-response type control. One such example, in which a step response of 500 MW at the time of the outage is held for 5 seconds, then ramped to 400 MW with a 100-MW modulation signal tuned to damp the 0.63-Hz mode superimposed, is shown in Figure 3-10. This approach provides very similar control leverage to that of a 500-MW step-response. However, the energy requirement is markedly less, as shown in Figure 3-11.

The SMES controller provides power (and energy) throughout the 20-second simulation. As shown in Figure 3-11, the energy requirements monotonically increase the longer the SMES device is required to provide power for stabilizing the system. In actuality, the power could be removed after the system migrates to a stable operating condition or operator intervention is effected, in either case up to several minutes may be required. However, because these time-frames are beyond the horizon for transient stability simulation, they were not investigated in detail.

Table 3-4
SMES Substitution for Generator Dropping

Generator Dropping (MW)		Reduction		SMES Power Needed at Lugo (MW)
Baseline	With SMES	(MW)	Percent	
2700	2000	700	25	450
2700	0	2700	100	2500

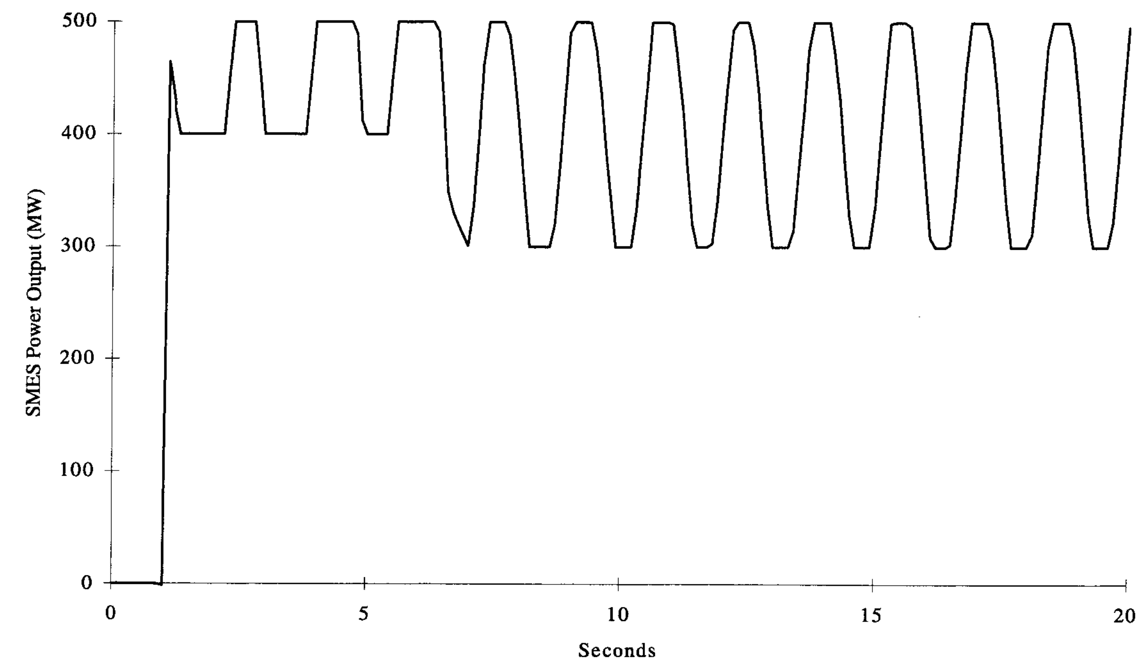

Figure 3-10
SMES power output for the PDCI outage case (HS8) showing the superimposed step and modulation control response.

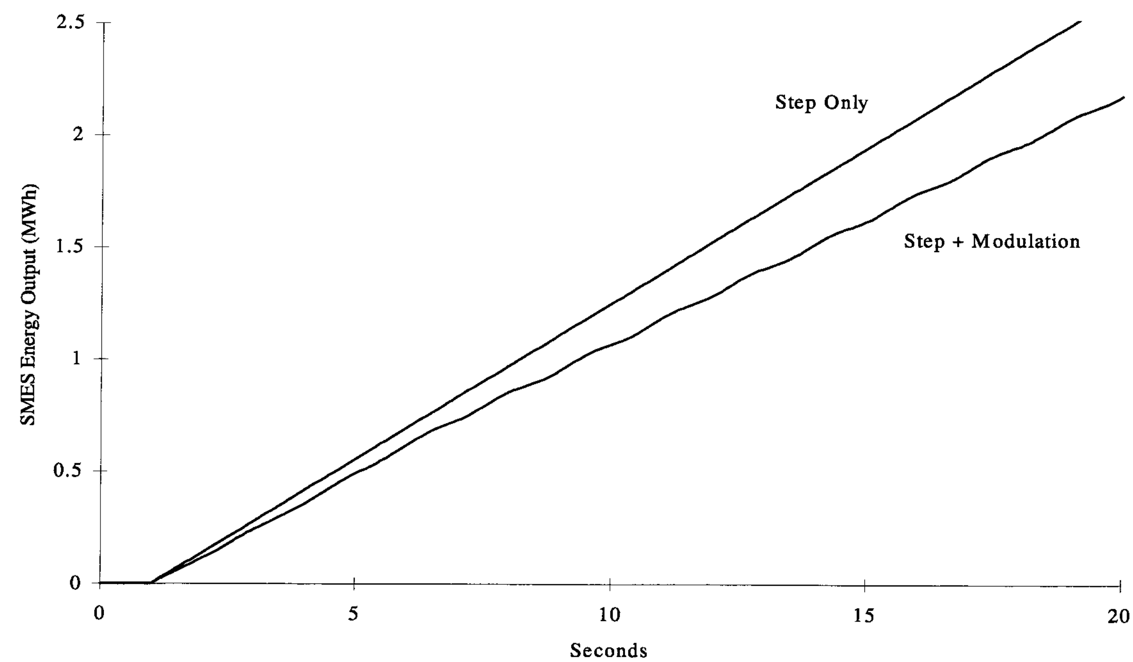

Figure 3-11
SMES energy requirements of the step and modulation control versus a simple step response-type control.

Intermountain DC Bipolar Outage (HS9)

The IPP bipolar DC outage case, with the implementation of the switching sequence from the PAST Handbook (Mackin et al. 1994), resulted in a stable benchmark case. Generator dropping was removed incrementally, and no instability was observed, as shown in Figure 3-12. However, with the addition of 200-MW SMES modulation at Lugo, an improvement in damping was observed, as shown in Figure 3-13.

Table Mountain Contingency (HS10)

The Table Mountain study case, implemented with the switching sequence from the PAST Handbook (Mackin et al. 1994), resulted in a stable response to the benchmark loading conditions. Furthermore, when generator dropping was removed, no instability was observed, as shown in Figure 3-14. Therefore, under this set of conditions, there is no opportunity to enhance the system response with SMES real-power modulation.

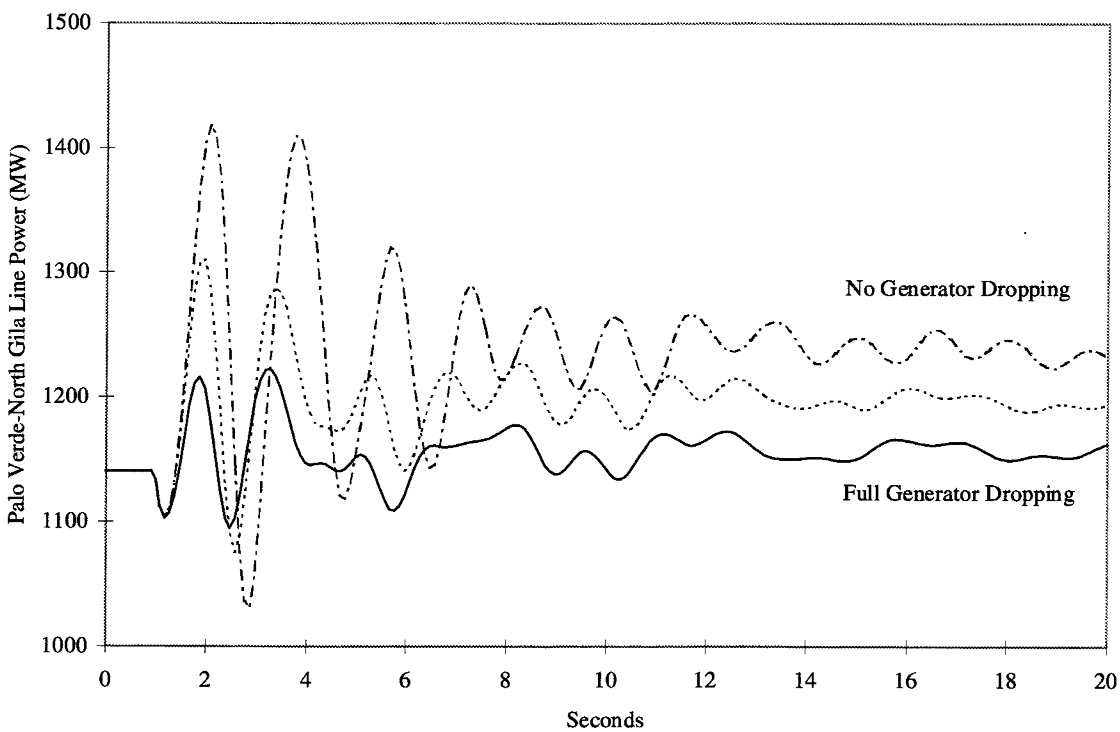

Figure 3-12
Palo Verde-North Gila line MW flow response to the IPP DC bipolar contingency with varying degrees of generator dropping.

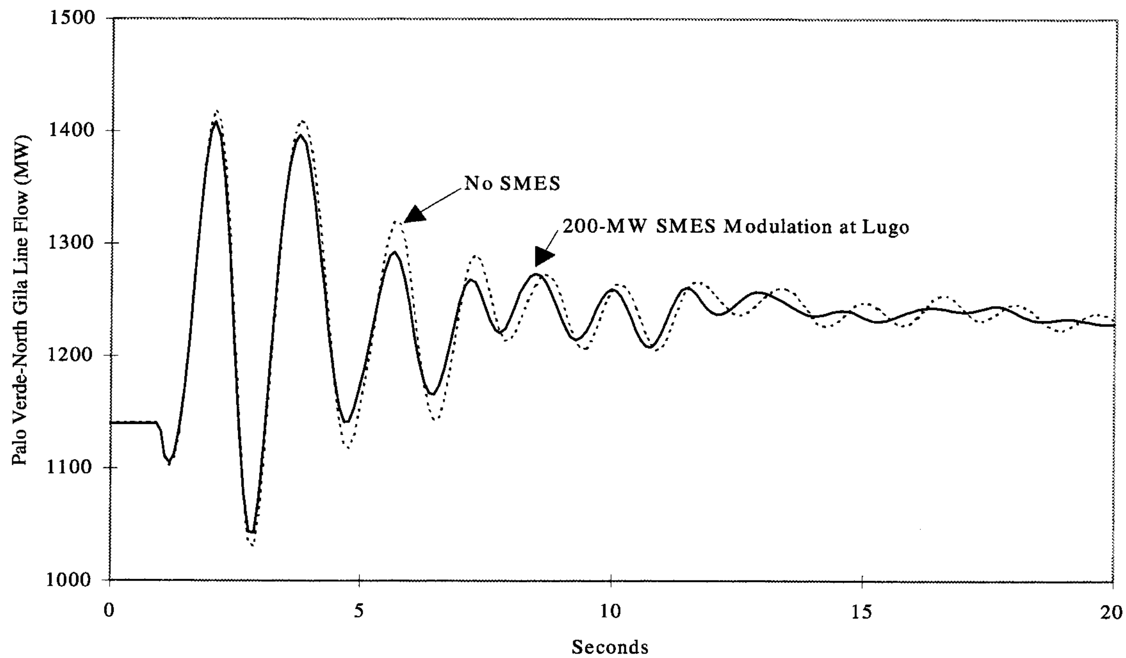

Figure 3-13
Palo Verde-North Gila line MW flow response to the IPP DC bipolar outage with no generator dropping.

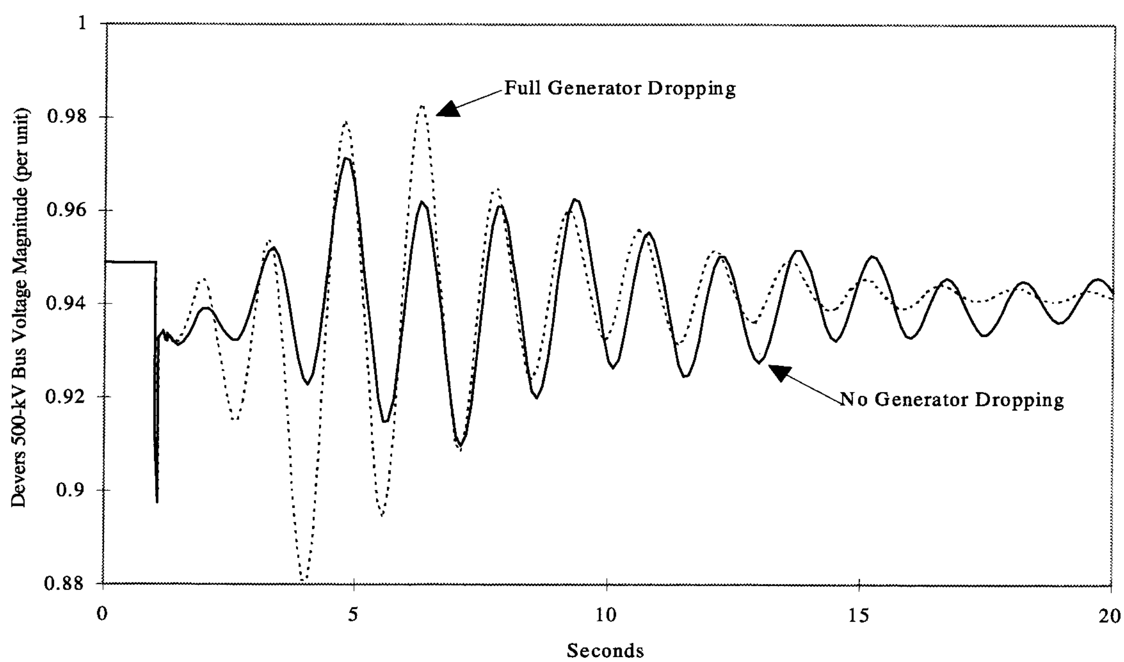

Figure 3-14
Devers voltage magnitude for the Table Mountain contingency.

Prior to the recent completion of the Third AC Intertie project, this contingency relied on a controlled north-south separation as part of the remedial action scheme. With the additional transmission assets connecting the north and south portions of the system, a complete separation is no longer necessary to maintain stability. Nevertheless, generator dropping is still an important part of the remedial action scheme to prevent overloading the remaining portions of the system when this contingency occurs, which is demonstrated in Figure 3-15. The system configuration and loading conditions modeled for this case show no benefits attributable to SMES. Under different configurations or loading conditions, however, SMES could provide an important role augmenting or replacing existing remedial action schemes.

Palo Verde-Devers Contingency Sensitivity Case

An additional sensitivity case was performed to determine if the SMES modulation control at Lugo could provide transmission loading enhancement for the Palo Verde-Devers line outage contingency. This disturbance consists of a three-phase fault at the Palo Verde 500-kV bus followed by the loss of the Palo Verde-Devers 500-kV line. This line is one of the major tie lines between Arizona and Southern California. The modeled disturbance is similar to the Palo Verde-North Gila line outage contingency (assessed in cases HS1, HS2, HS6, HS7a and HS7b) with respect to its being a limiting contingency for determining Southern California transmission imports.

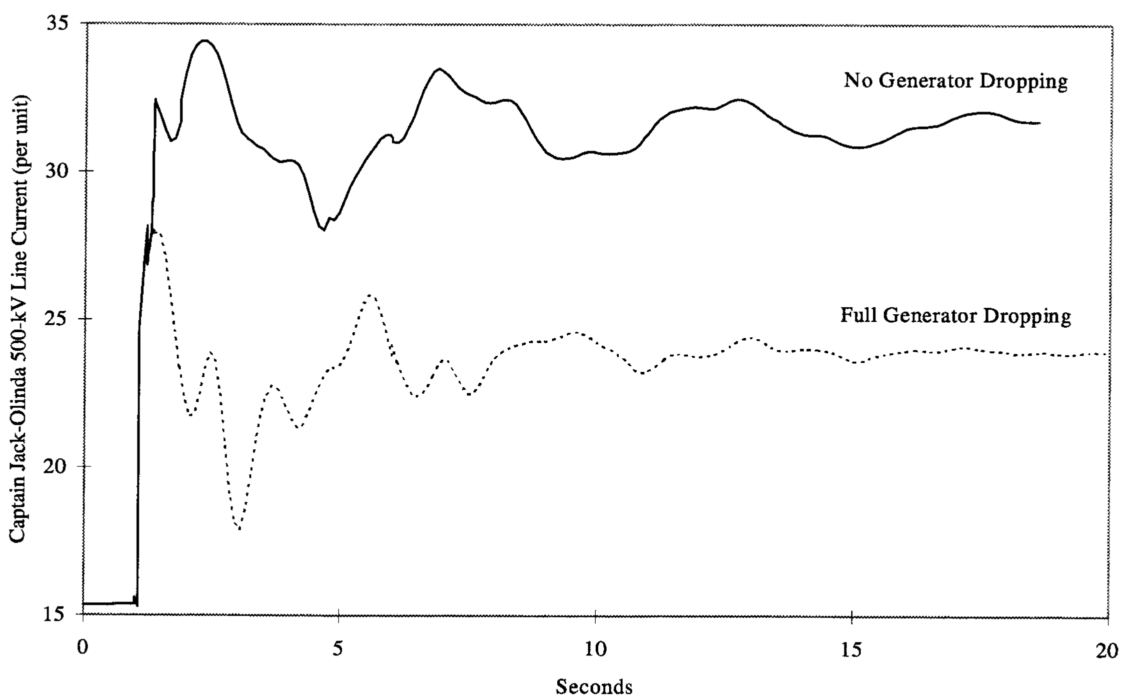

Figure 3-15
Third AC-Intertie current magnitude resulting from the Table Mountain contingency.

A 250-MW SMES unit located at Lugo could provide sufficient damping to enable a 500-MW increase in WOR loading over benchmark loading conditions, as shown in Figure 3-16. However, because the marginally-damped case was derived using the Palo Verde-North Gila line outage contingency, not all of the increase in WOR flow is attributable to SMES modulation. Figure 3-17 shows that, without SMES-supplied modulation, the system was stable with WOR increased by 100 MW, but unstable with WOR increased by 300 MW.

This sensitivity indicates that the SMES controller at Lugo could provide positive damping for both the Palo Verde-North Gila and Palo Verde-Devers contingencies, enabling an increase in Southern California imports that would otherwise be constrained by stability limitations. The limiting contingency (Palo Verde-North Gila) was used to define the increases in transmission loadings enabled by SMES modulation, which is also able to provide stability enhancement for the Palo Verde-Devers contingency.

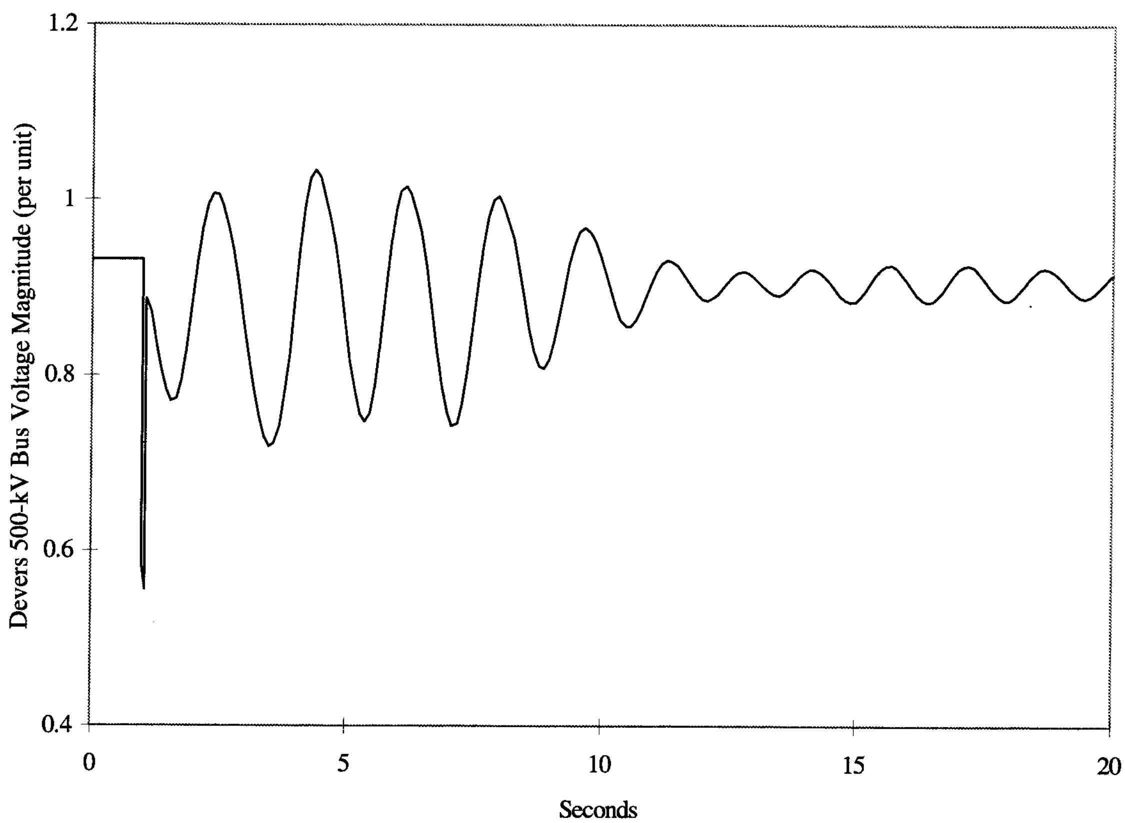

Figure 3-16
Devers voltage response to the Palo Verde-Devers contingency with 250-MW SMES unit at Lugo with 500-MW increase in WOR loading.

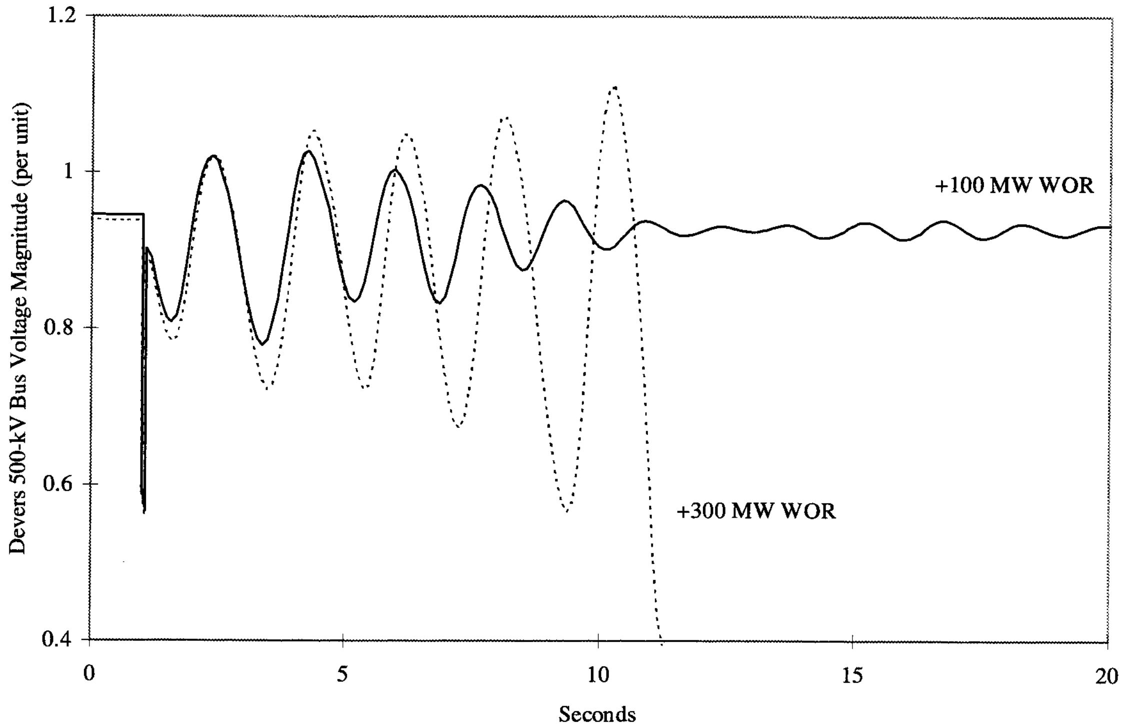

Figure 3-17
Baseline Devers voltage response to the Palo Verde-Devers contingency with increased WOR loading.

Stability Margin

As indicated above, marginally-damped loading conditions determine the absolute limits of power imports available into the Southern California area. However, a stability margin of 500 MW is added when establishing the maximum imports under actual operating conditions. The WCUG advisors expressed interest in an evaluation of the system response to the Palo Verde-North Gila outage with the 500-MW stability margin taken into account.

In this evaluation, the baseline system at the maximum level of import was defined by the marginally-damped case established in the analysis of case HS7b with a 500-MW stability margin subtracted from the WOR loading. With 550 MW of SMES modulation added at Lugo, the transmission limits could be safely increased by 500 MW. The system response to the Palo Verde-North Gila contingency is shown in Figure 3-18.

In addition to increasing the amount of power imports available to Southern California by 500 MW, the SMES device also improves damping of what would otherwise have been a lightly-damped, albeit stable, response.

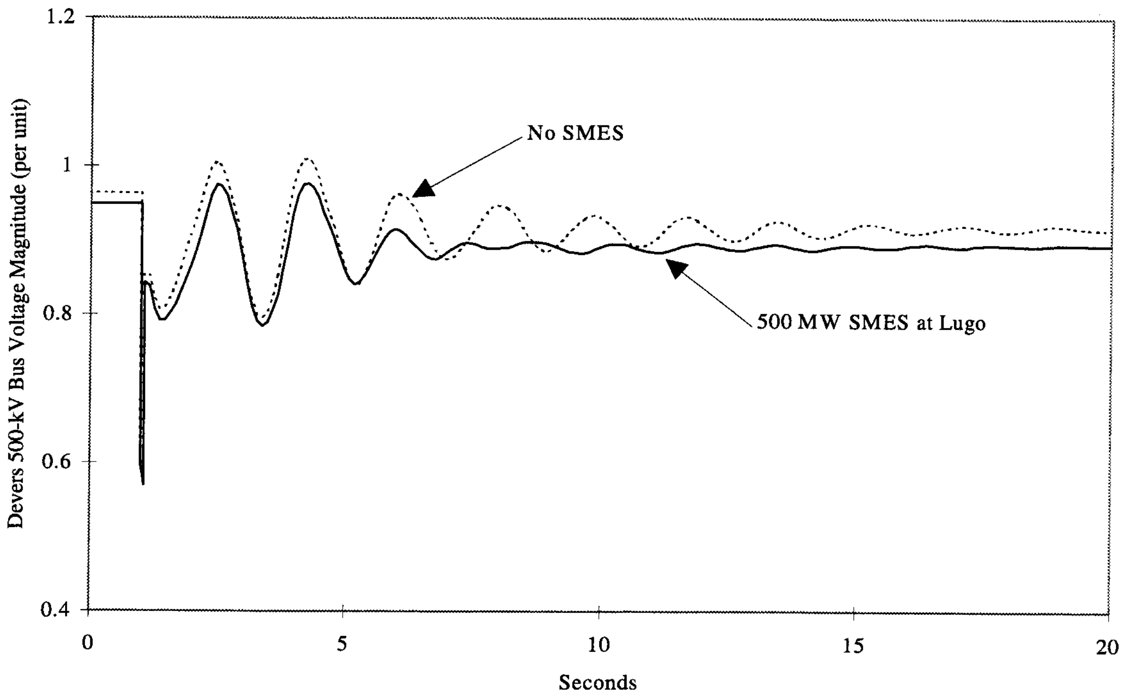

Figure 3-18
Devers voltage response to the Palo Verde-North Gila contingency with SMES-enabled 500-MW WOR loading increase and 500-MW stability margin taken into account.

Imminent Voltage Collapse in Case HS6

Further examination of case HS6 indicated the possibility of an imminent voltage collapse problem. This presented an opportunity to compare SMES real-power modulation with an alternative control solution using capacitors. As in case HS6 and with loading conditions specified in Table 3-2, WOR loading was increased by 500 MW. Real-power modulation from SMES was used to achieve a stable case under loading conditions that would otherwise be unstable. Capacitor additions were simulated at selected buses in the LA Basin to provide sufficient voltage support so that the system showed a similarly stable response to the Palo Verde-North Gila line outage contingency. The results of this exercise showed that capacitors could provide stability control similar to that of a 250-MW SMES unit, although unwieldy amounts would be needed. Further investigation of these voltage collapse characteristics would be required to draw definitive conclusions about alternate methods of enhancing system stability.

Alternative Control Approaches at Chino

The quality and cost-effectiveness of stability control provided by SMES and other approaches are highly sensitive to the location of control insertion. In preparation for assessing the benefits of alternative control approaches (discussed in Section 4), a comparison was made between real- and reactive-power modulation to determine if either approach provided differential leverage in power transfer enhancement. At EPRI's request, Chino was a site investigated for this purpose. The analysis focussed on case HS7b with a 100-MW simultaneous increase in EOR and WOR transmission beyond the SCIT-2 benchmark loading conditions. To facilitate the assessment, real-power modulation from SMES was simulated, as described in Section 2. A controller for reactive-power modulation was designed and implemented, based on principles similar to those developed for real-power modulation. In addition, a step insertion of reactive power was evaluated to ensure that the instability being modeled was not simply a voltage support issue that could be managed by application of fixed capacitor banks. The results of this comparison are shown in Table 3-5 and indicate that, at Chino, real-power modulation (from SMES) has a larger control leverage (ratio of increased loading to modulation power) than either reactive-power modulation (from SVC) or a reactive-power step supplied by fixed capacitors.

In addition to the above analysis, combinations of real-power modulation and reactive-power steps were explored. It was found that a 200-MVAR step would reduce the real-power modulation requirement by only 10 MW, indicating that an electromechanical oscillation is the principal mode to be controlled, rather than a response that is exacerbated by inadequate voltage. The above results confirm that both real- and reactive-power modulation inserted at Chino can enhance EOR and WOR transmission simultaneously.

Comparison of SMES and SVC Control Leverage

The control leverage of SMES and SVC was compared at a chosen site to establish a basis for making an economic comparison between alternative control approaches. Ideally, each technology should be compared at the control insertion site that would maximize its control leverage. The resources of this project did not allow an exhaustive comparison of the best site for each option, which would have required an independent, system-wide evaluation. Initially, Lugo was considered as a site for this comparison because, as indicated above, this is a good location to insert SMES real-power modulation. However, Lugo can be expected to be a far less favorable

Table 3-5
Chino Analysis Results

Control Alternative	100-MW Transmission Enhancement	
	Minimum Control Required	Leverage
Real-power modulation	130 MW	0.77
Reactive-power modulation	190 MVAR	0.52
Steady-state reactive power	700 MVAR	0.14

site for SVC, as is evident by its proximity and similarity to the Chino case described above. The choice of Lugo would have been, therefore, unreasonably prejudicial to the SVC case. As a compromise, Devers was selected for the control leverage comparison because it is a known location were both real- and reactive-power modulation can provide beneficial system enhancement.

The comparison was conducted in a similar manner to that described above in the Chino case using the real-power controller developed in the analysis of case HS7a. The process of designing modulation controls, as described in Section 2, was repeated for reactive-power injection at Devers. Control leverage of SMES and SVC was investigated over a range of WOR transmission capacity enhancement between 100 MW and 500 MW beyond the SCIT-2 benchmark loading conditions with the limiting contingency defined in case HS2. The WOR enhancement provided by both real- and reactive-power modulation located at Devers is given in Table 3-6.

Above the 100-MW WOR transmission enhancement level, SVC reactive-power modulation was found to control the characteristic 0.5-Hz system oscillation with somewhat better leverage than that provided by SMES real-power modulation. Using the approach described earlier, candidate sites in the LA Basin were evaluated for controllability and observability with respect to modulating reactive power. Location was shown to be a more important consideration for reactive-power modulation than for real-power modulation. While this analysis confirmed that Devers could be a good site for SVC control, the possibility of there being an even better site for SMES was not evaluated.

Table 3-6
Control leverage provided by SMES and SVC at Devers

WOR Transmission Enhancement (MW)	Minimum SMES/SVC Device MVA Rating	
	Real Power Modulation (MW)	Reactive Power Modulation (MVAR)
100	80	80
300	260	250
500	480	450

4

ECONOMIC COMPARISON OF ALTERNATIVES

While the primary focus of this study was to assess the ability of SMES to enhance the stability and power transfer of selected pathways in the utility transmission system serving Southern California, a secondary objective was to compare the value of SMES benefits and costs with those of alternative control approaches. This section summarizes the economic inferences that can be drawn from the system dynamic analyses reported in Section 3.

Value of Transmission Enhancement Benefit

The value of increasing transmission capacity is highly application specific and is a complex function of the utility's ability to market additional power and to meet other financial or strategic objectives. Several scenarios assessed in this report show that SMES real-power modulation could allow increased imports into the Southern California area. For the purposes of this study, the benefit value of this SMES-enabled transmission enhancement was assumed to be $10,000/MW-year. This value was recommended by the WCUG advisors and represents the annual worth of adding transmission capacity to a system. It may also be interpreted as potential revenue gained from power sales enabled by SMES at times when the transmission system would be otherwise constrained. For example, $10,000/MW-year is equivalent to SMES-enhanced power sales worth 20 mills/kWh for an average of 500 hours per year, or other combinations of incremental energy profit potential and hours per year that the present system is constrained. This value may be somewhat conservative, particularly in the emerging arena of increased retail wheeling and power marketing, which may provide enhanced revenue potential for utilities that increase their transmission capacity.

SMES Cost Estimation

The capital cost expression for SMES applications assessed in this study is the equation on page 4-17 in the report "SMES Plant Costs: EPRI Estimate" (EPRI 1995). This equation is the basis recommended by EPRI for estimating nth-of-a-kind plant costs in 1993 dollars.

Benefit/Cost Comparison of SMES and SVC at Devers

As indicated in Section 3, the estimation of control leverage provided by real- and reactive-power modulation at Devers enabled a simple comparison between the benefit values and capital costs of competing control options. The control leverage characteristics of SMES and SVC from

Table 3-6 were compared at three levels of WOR transmission enhancement; 100 MW, 300 MW and 500 MW. Based on the transmission benefit of $10,000/MW-year, added power transfer capacity has an annual worth of $1 million, $3 million and $5 million, respectively. The present value of transmission enhancement was calculated on the basis of a constant annual benefit provided over the 30-year life span of the control device. Future benefits were estimated in constant 1993 dollars and discounted to present value, using a real discount rate of 6%. This interest rate reflects the net opportunity cost for a typical utility. Constant dollar analysis was used, in which all future inflationary or deflationary trends are assumed to occur equally to both annual costs and benefits in future years, the effect of which can be netted out.

SMES capital costs were estimated by inserting energy and power requirements in the EPRI cost expression for each level of power enhancement. Energy requirements govern coil-related costs. To minimize these costs, the minimum energy storage capacity of SMES needed at each level of enhancement was determined from the power modulation requirement. As described previously, power transmission between Arizona and Southern California can be enhanced by controlling the 0.5-Hz oscillatory mode. Energy is exchanged between SMES and the transmission system during each period of the oscillation, with the energy exchange decreasing gradually as the oscillation is progressively damped. The energy storage requirement represents about 1 second of full power discharge (i.e., the energy required during the first and largest half-cycle of the oscillation) and represents the storage capacity necessary to provide sufficient damping, assuming no losses. Energy requirements determined in this manner established coil-related costs in the EPRI cost expression. Corresponding power-handling requirements were determined from the control leverage characteristics given in Table 3-6. The control power required for each level of transmission enhancement was used to estimate the cost of the power conditioning system represented in the EPRI cost expression.

Table 4-1 compares benefits and costs of transmission enhancement provided by SMES at Devers. SMES is shown to have net present value (NPV) that becomes positive when the transmission enhancement is greater than 100 MW. In this case, NPV is the amount by which the present value of the transmission benefit exceeds the capital cost of SMES. The system being assessed is considered cost-effective whenever the NPV is greater than zero, and the maximum NPV is desired when evaluating alternative configurations or strategies.

As indicated in Table 3-6, SVC reactive-power modulation at Devers was found to provide somewhat better leverage than real-power modulation from SMES. The breakeven cost of SVC in $/kVAR that would require the same capital investment and provide the same NPV as SMES is given in Table 4-2. Recent SVC project quotations and installations on WCUG-member systems, which vary dramatically based on the application, range between $40/kVAR to $100/kVAR. For 100-MW and 300-MW transmission enhancement, breakeven costs exceeding this range in Table 4-2 indicate SVC would have a higher NPV than SMES in these cases. However, at the 500-MW level of transmission enhancement, SMES becomes cost effective when compared to the upper bound of the SVC cost range.

Table 4-1
Cost and Benefit Summary of SMES at Devers

Transmission Enhancement (MW)	SMES Power (MW)	SMES Energy (kWh)	Present Value ($M)		
			Cost	Benefit	Net
100	80	22	18.5	13.8	-4.7
300	260	72	30.1	41.3	11.2
500	480	133	42.4	68.8	26.5

Table 4-2
Devers SVC Beakeven Cost

Transmission Enhancement (MW)	SVC Modulation Requirement (MVAR)	SVC Breakeven Cost ($/kVAR)
100	80	230.6
300	250	120.2
500	450	94.1

Case HS6 Economic Evaluation

As indicated in Section 3, case HS6 presented an opportunity to compare SMES real-power modulation with the alternative of using capacitors to prevent an imminent voltage collapse, which appeared under the increased loading conditions of this case. Real-power modulation from SMES control was used to achieve a stable case under loading conditions that would otherwise be unstable. When inserted near Palo Verde, 250 MW of SMES real-power modulation costing $31.7 million allowed a WOR loading increase of 500 MW with a present value of $68.8 million. The corresponding NPV was $37.1 million. A cursory review of adding capacitors at selected buses to obtain comparable stability control was made, which was not cost-effective. While capacitors may not be the least-cost alternative to SMES, this example taken in conjunction with the others reported in this section, illustrate the need for exhaustive location-specific analysis to identify control options with the largest net benefit.

Comparison of Alternative Control Approaches at Chino

As reported in Section 3, Chino was selected as a site where the control leverage of SMES real-power modulation could be compared to that of SVC reactive-power modulation and a reactive-power step supplied by fixed capacitors to enable a simultaneous EOR and WOR loading increase of 100 MW. The respective control leverage of each option shown in Table 3-5 was used to estimate ratings and, hence, the capital costs of the control alternatives shown in Table 4-3. As before, the capital cost of SMES was estimated using the EPRI cost expression (EPRI 1995) and the cost of capacitor additions was assumed to be $20/kVAR. In the Chino comparison, the SVC cost was assumed to be $70/kVAR, the median value of the aforementioned cost range. Net present value was calculated as the difference between the present value of the transmission enhancement benefit ($13.8 million) and the capital cost of the respective alternatives. Table 4-3 shows that SVC is the only option having a positive NPV under the particular conditions assessed in this comparison. This case provided further evidence that the quality and cost-effectiveness of stability control provided by SMES and other approaches are highly sensitive to the location of control insertion.

Multiple Benefits of SMES

In contrast to alternatives such as SVC and capacitors, a major advantage of SMES is its ability to provide several system benefits at a single location. Therefore, in comparing SMES with alternatives on the basis of a single benefit, the above assessments fail to show the total potential value of SMES at the sites considered in this study. While the evaluation of these benefits was beyond the scope of this project, the following list illustrates the range of benefits, in addition to the real-power modulation control assessed in this study, that SMES may be able to provide depending on prevailing site-and system-specific circumstances.

- Load leveling - SMES provides dispatchable capacity to supply peak loads when generation costs are highest, achieved by storing low-cost off-peak energy.

Table 4-3
Alternatives at Chino for a 100-MW EOR and WOR Loading Increase

Control Alternative	Minimum Control Requirement	Capital Cost ($M)	Net Present Value ($M)
SMES real-power modulation	130 MW	22.0	-8.2
SVC reactive-power modulation	190 MVAR	13.3	0.5
Capacitor steady-state insertion	700 MVAR	14.0	-0.2

- Spinning reserve - SMES supplies part of on-line synchronous generation reserve requirements.

- Load following - SMES supplies the minute-by-minute variation in system demand to keep generation set points as constant as possible.

- Automatic generation control (AGC) - SMES is incorporated in AGC to maintain system frequency, improve scheduling of control generators and reduce governor wear.

- Ramping - SMES allows the stepping of system generation in large blocks when desired, by compensating the ramp rate limits of conventional generators. SMES would discharge to supply the load during ramp-up and recharge during ramp-down periods.

- Optimum loading of generators - SMES can facilitate operation of conventional generators at optimum settings to maximize thermal efficiency and reduce cycling at times of minimum load.

- Voltage support - SMES provides reactive-power compensation to increase power transfer and stability limits of transmission systems.

- Black start - SMES allows a utility to pick up and maintain load without any tie to an active power system.

Additional benefits include subsynchronous resonance mitigation and the use of SMES as a programmable system testing tool. With the ability to create controllable, predefined perturbations to system operation, this tool could provide system planning information superior to that generated by other means. A SMES unit at a given location could provide a combination of these benefits, either simultaneously or sequentially, as system conditions dictate.

Other SMES studies of applications in the Pacific Northwest (De Steese et al. 1992) and New Mexico (De Steese and Dagle 1994) show that benefits generally exceed cost when several benefits are enabled by a single device. Single-purpose SMES applications may not, however, be cost-effective when compared to alternate technologies. It is likely that an evaluation of other SMES benefits at the locations studied in this project would show SMES to be more attractive and cost-competitive than is indicated by the analyses performed in this study.

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CONCLUSIONS AND RECOMMENDATIONS

This report presents the results of a feasibility scoping study to evaluate the use of SMES to increase power transfer on selected transmission paths in the western region of the North American power system. SMES power modulation to stabilize electromechanical oscillations resulting from disturbances on the system was shown to increase the transmission capability of the existing system by several hundred megawatts, thereby increasing available power imports into Southern California.

The effectiveness of SMES to enhance transmission stability varied considerably according to the scenario considered. With a three-phase fault at Palo Verde and loss of the Palo Verde-North Gila line, a 250-MW SMES unit enables WOR transmission to be increased 500 MW above marginally-damped loading conditions when located one-quarter of way along the Palo Verde-Devers line. The energy storage capacity requirement for this application would be about 500 MW-seconds (140 kWh). Under the same contingency and with the SMES unit located at Lugo, the control leverage varied greatly depending on the magnitude of the enhancement and the transmission paths affected. An evaluation of SMES-enabled EOR loading increases between 100 MW and 500 MW showed control leverage as high as 3:1. In contrast, WOR leverage was found to be a maximum of unity at 100 MW and as low as 0.85 at higher enhancement levels. The ability of SMES to increase power flow into Southern California from Arizona, determined by the effectiveness in increasing EOR and WOR loadings simultaneously, proved to be the most stringent of the three conditions showing SMES control leverage no greater than 0.67.

Two scenarios investigated the ability of SMES to reduce the amount of remedial action needed if dc interties are lost. Results showed that a SMES unit located at Lugo has the ability to compensate the need to drop generation in the event of a Pacific DC Intertie bipolar outage. In contrast, the Intermountain Power Project bipolar dc outage case showed no instability, and hence, no opportunity for SMES to provide a significant control function. Nevertheless, a 200-MW SMES device at Lugo was found to improve damping.

In the final WCUG scenario, the contingency evaluated was a three-phase fault at Table Mountain with loss of Table Mountain-Tesla and Table Mountain-Vaca Dixon lines. No adverse impacts were determined for the benchmark loading conditions. Furthermore, with generator dropping removed, the contingency does not create any instabilities, and thus provides no opportunity for a beneficial SMES control function.

A sensitivity case was evaluated to investigate SMES control effectiveness in the event of a three-phase fault at the Palo Verde bus followed by the loss of the Palo Verde-Devers 500-kV line. This contingency is also important when considering Southern California import limitations, even though the Palo Verde-North Gila contingency is usually the critical limiting factor. A 300-MW SMES device at Lugo was shown to enable a 500-MW increase in WOR loading over the benchmark load conditions, while the system was stable with WOR increased only 100 MW without SMES.

Transmission benefits of SMES were compared with those provided by other options. Modulation of real and reactive power at Chino was evaluated for a 100-MW simultaneous increase in EOR and WOR loadings to compare the control effectiveness of SMES, SVC, and fixed capacitors. The control quality provided by real-power modulation of SMES (130 MW, leverage 0.77) was found to exceed the leverage provided by SVC (190 MVAR, leverage 0.52) and fixed capacitors (700 MVAR, leverage 0.14).

The net present value of SMES and SVC was established as the difference between the present value of benefits and capital costs. SMES costs were based on a standard cost formulation developed by EPRI. SVC costs were considered to be between $40/kVAR and $100/kVAR, a range recommended by the WCUG. The NPV of both options was evaluated on the basis of their control effectiveness at Devers in enabling up to 500 MW of WOR transmission enhancement. The NPV of SMES real-power modulation becomes positive above the 100-MW level of WOR transmission enhancement and increases monotonically over the control range investigated. Over most of this range, however, reactive-power modulation provided by SVC was found to have better control leverage. The comparison of control effectiveness at Devers showed that SVC would have a significantly higher NPV than SMES in this particular application. Similar results were shown comparing SMES with SVC and fixed capacitors at Chino.

In this study, the comparison of SMES cost-effectiveness with single-purpose alternatives was too stringent a test of SMES competitiveness because a single SMES device is potentially capable of providing several system benefits at one location. While SVC may be generally more cost-effective than SMES as a single-purpose device, other SMES benefits (not evaluated in this study) could make it a cost-effective investment for enhancing transmission between Arizona and Southern California.

The above results are based on only one model of the future power system (a 1999 heavy summer case) which does not fully explore the potential of using SMES for stability control. A principal recommendation is that different models and loading conditions be evaluated with corresponding limiting contingencies to gain a more complete picture regarding control capabilities afforded by SMES. In addition, advanced stability control techniques, which may take advantage of simultaneous real- and reactive-power modulation, should be studied in detail. Future studies that may influence utility investment decisions should include all site- and situation-specific benefits of SMES and alternative control approaches to establish the overall least-cost or most valuable control option available.

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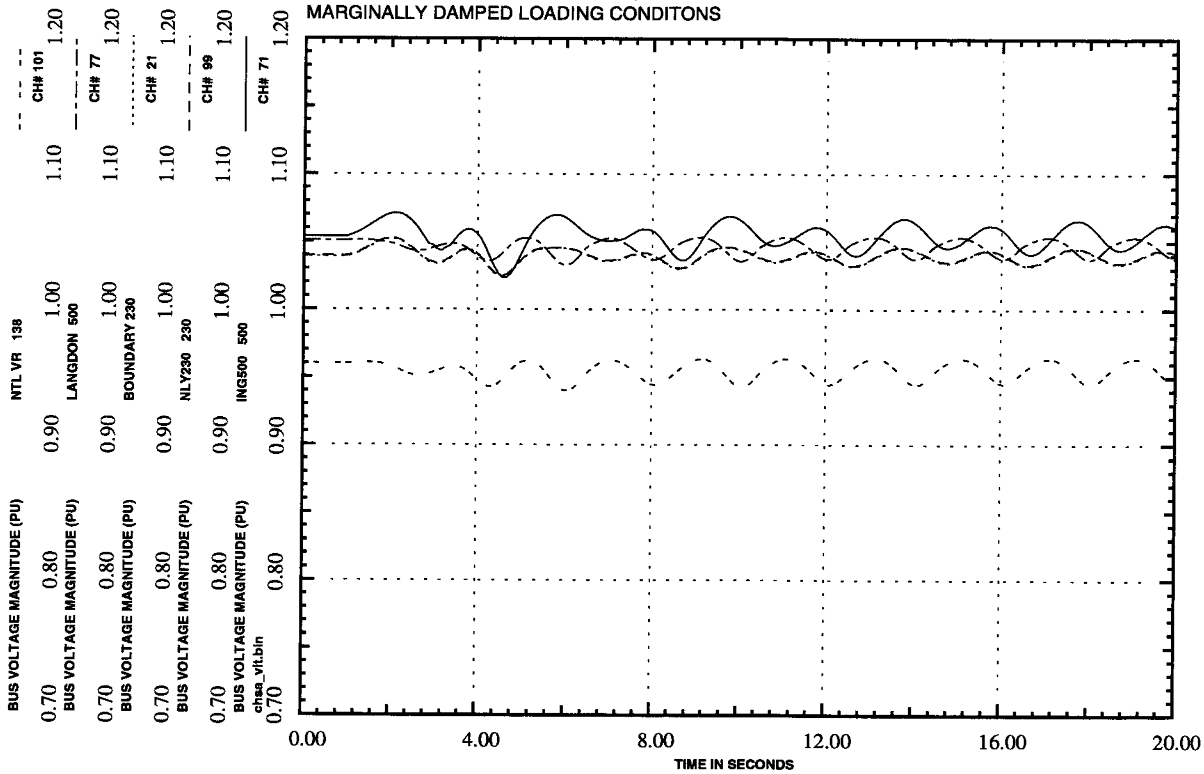
APPENDIX A

Simulation Results for SCIT-1 Benchmark Loading Conditions

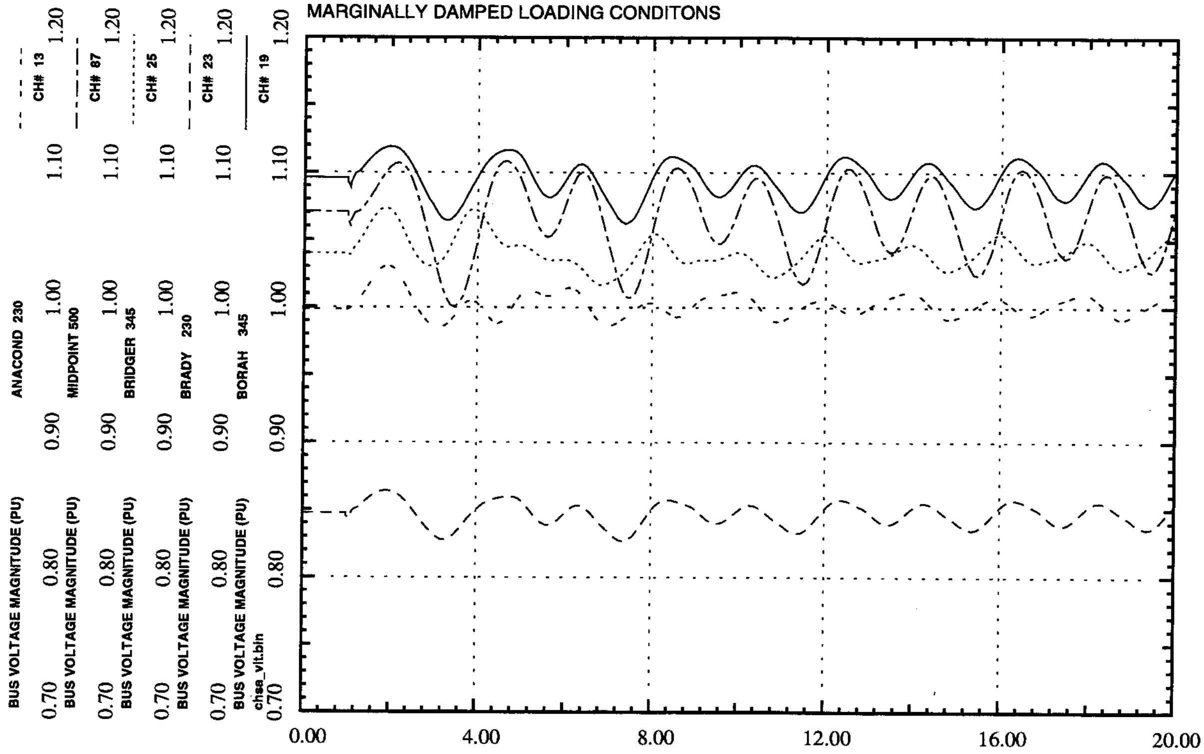
The following appendix contains ETMSP stability plots showing the simulated response to the Palo Verde-North Gila line outage contingency. Voltage magnitudes are plotted for buses in a given area, with 14 distinct groupings from throughout the system. A common voltage scale is used throughout all of the plots in this appendix.

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



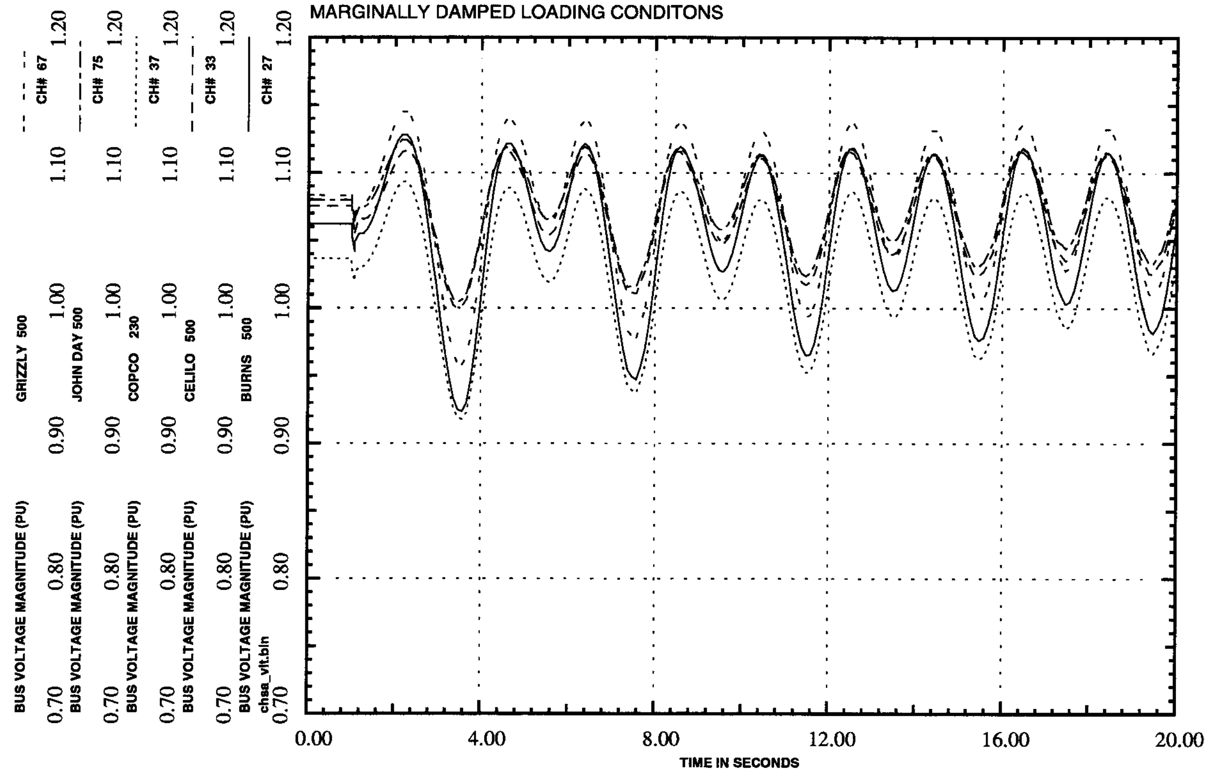
VOLTAGES NW, CANADA (V1)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



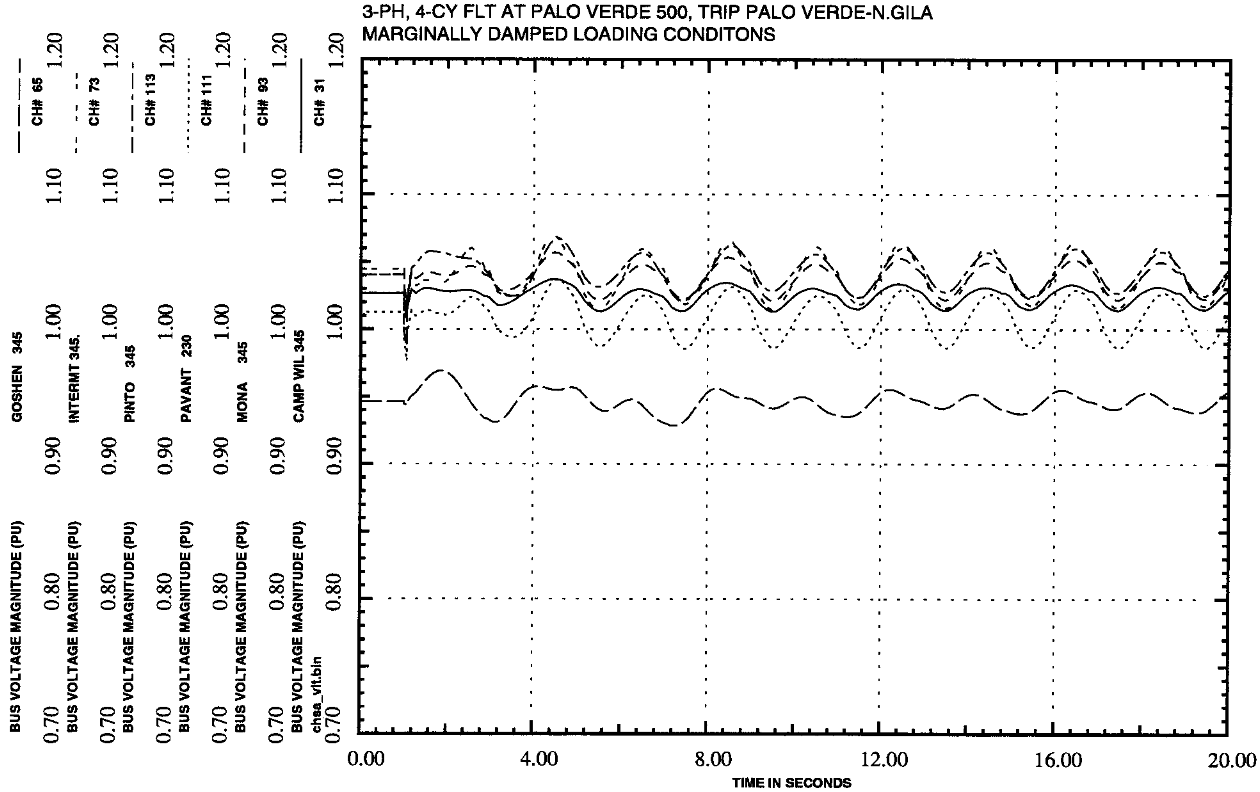
VOLTAGES IDAHO, MONT (V2)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



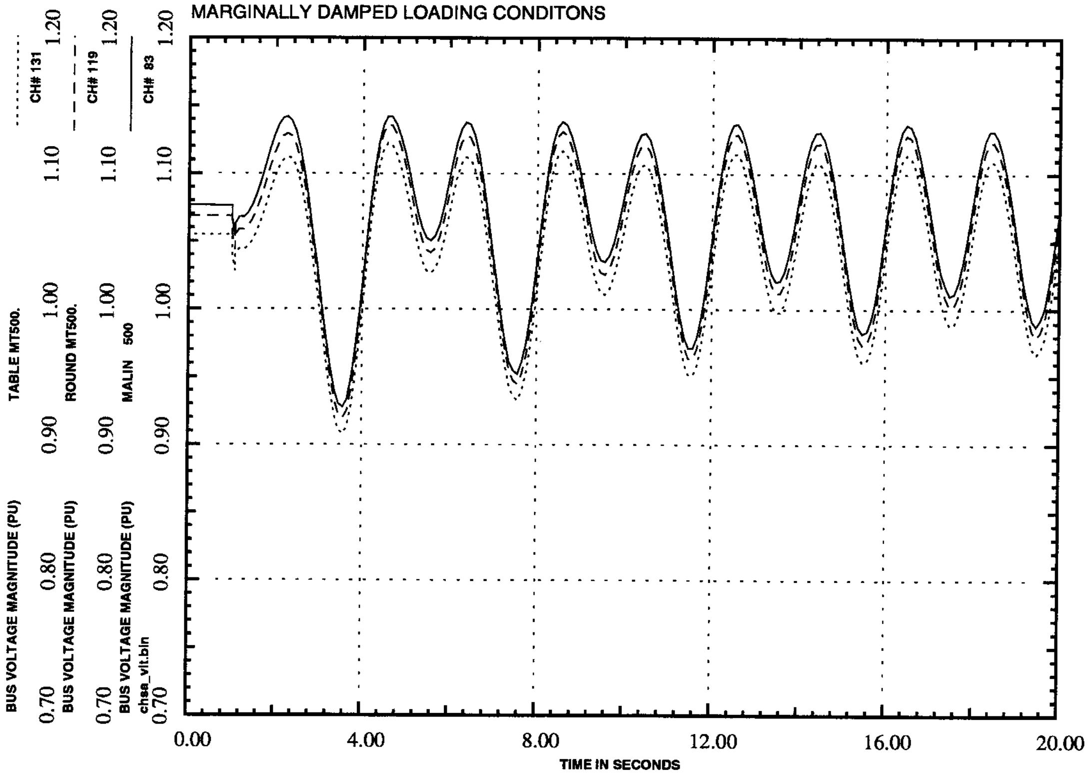
VOLTAGES NORTHWEST (V3)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



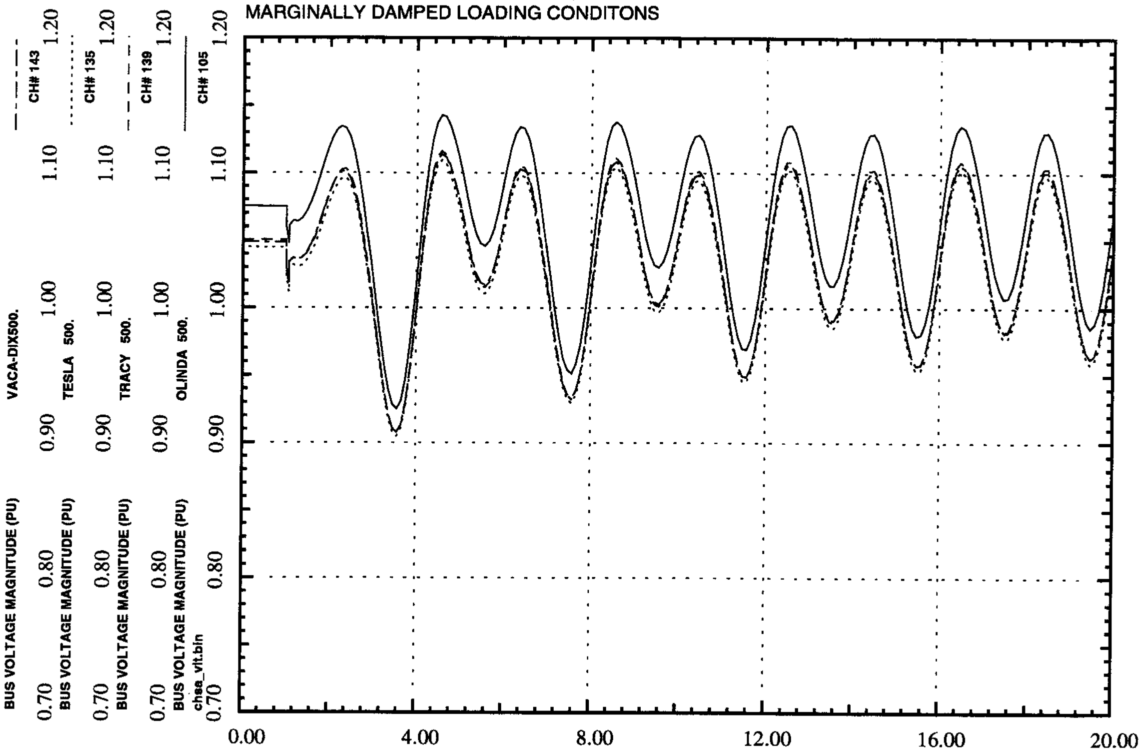
VOLTAGES UTAH (V4)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



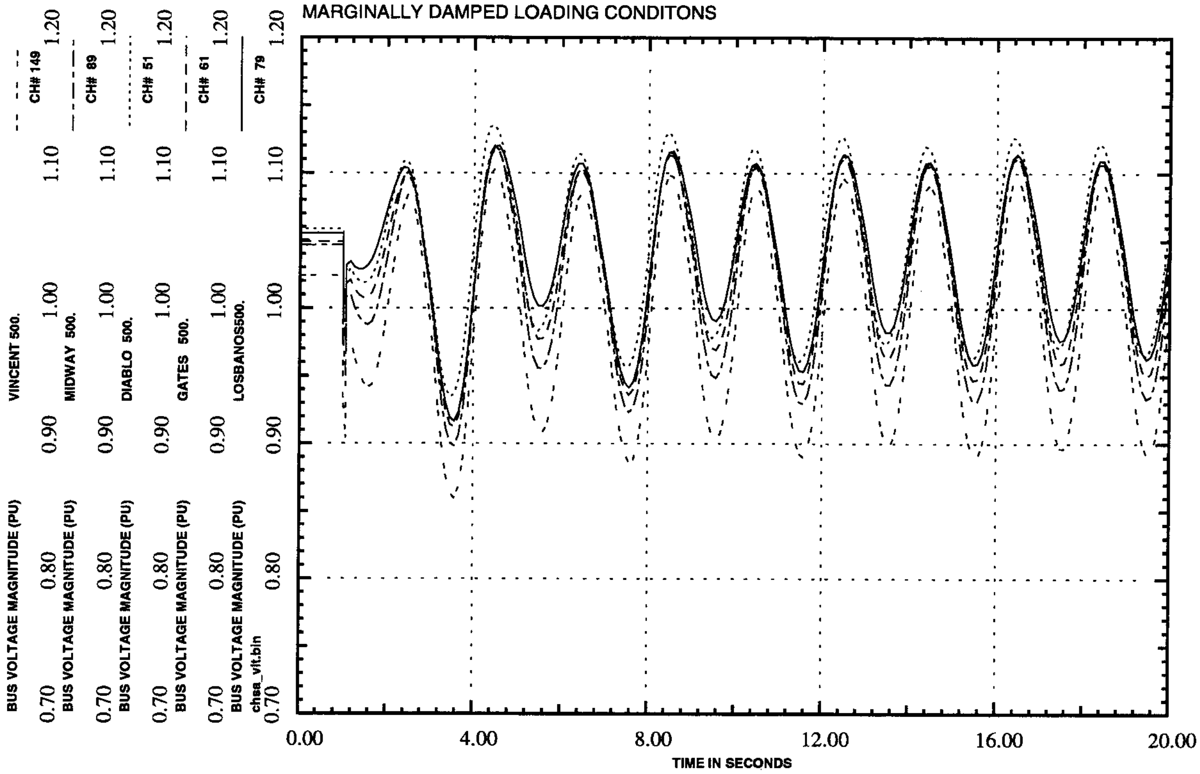
VOLTAGES PACI 1 (V5)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



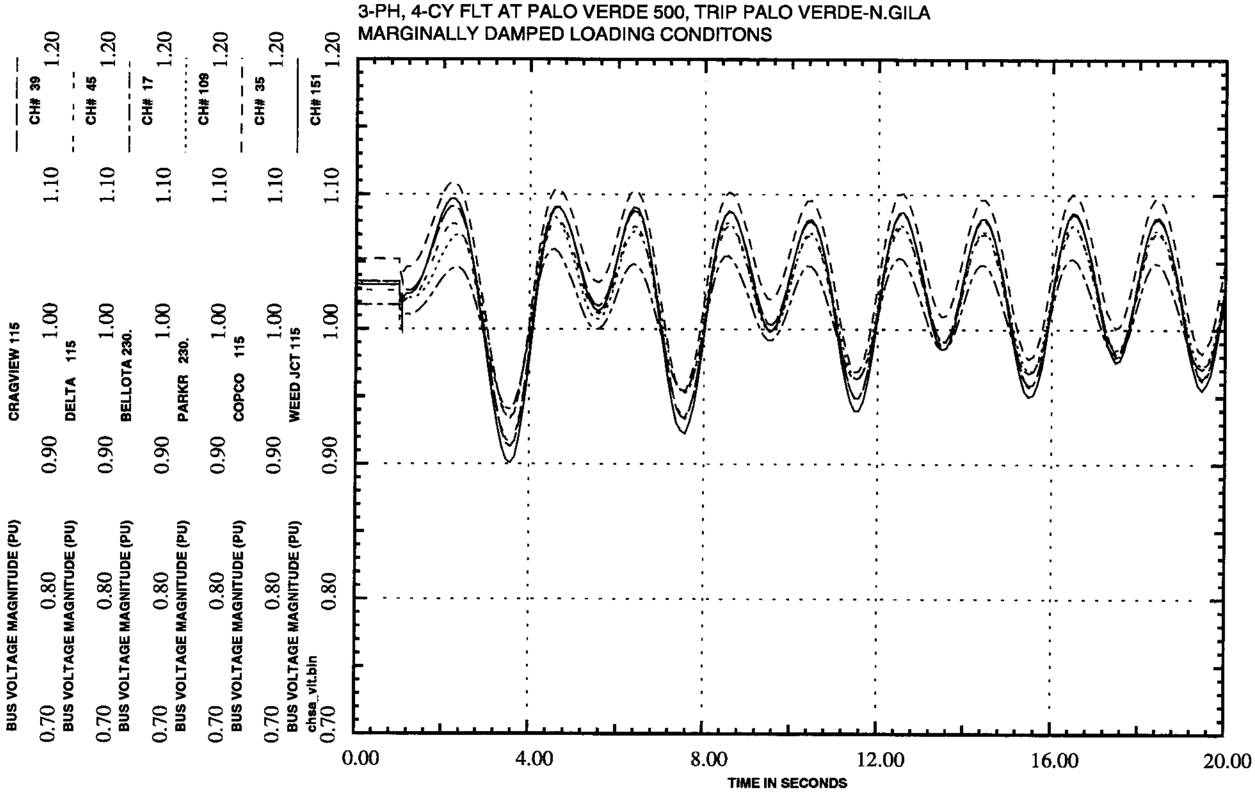
VOLTAGES PACI 2 (V6)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



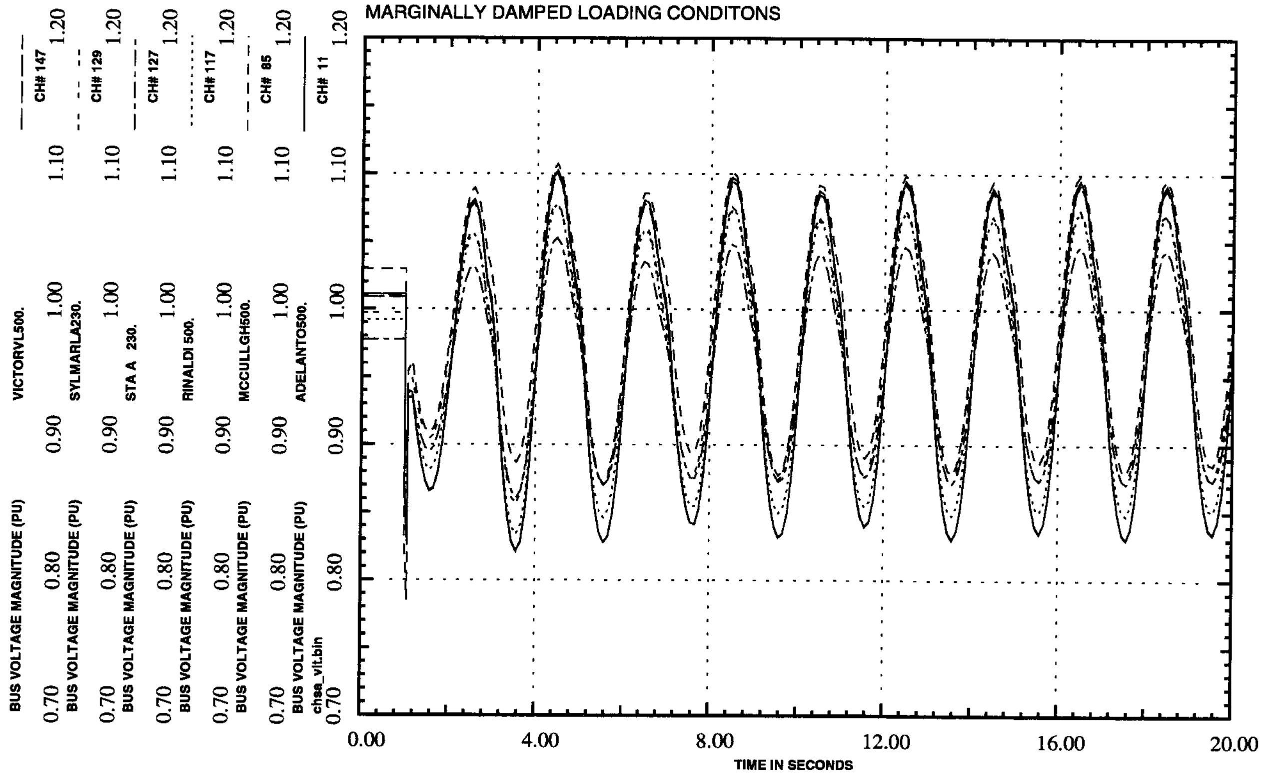
VOLTAGES PACI 3 (V7)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



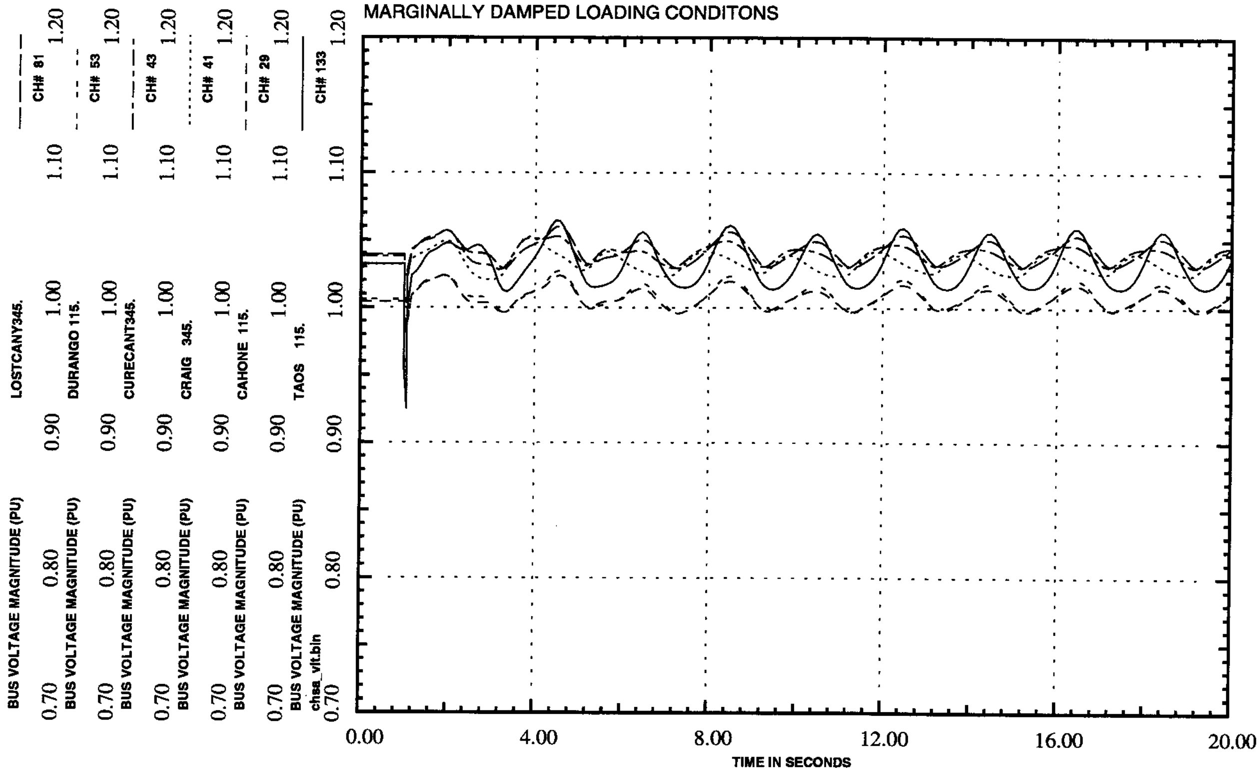
VOLTAGES MISC. (V8)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



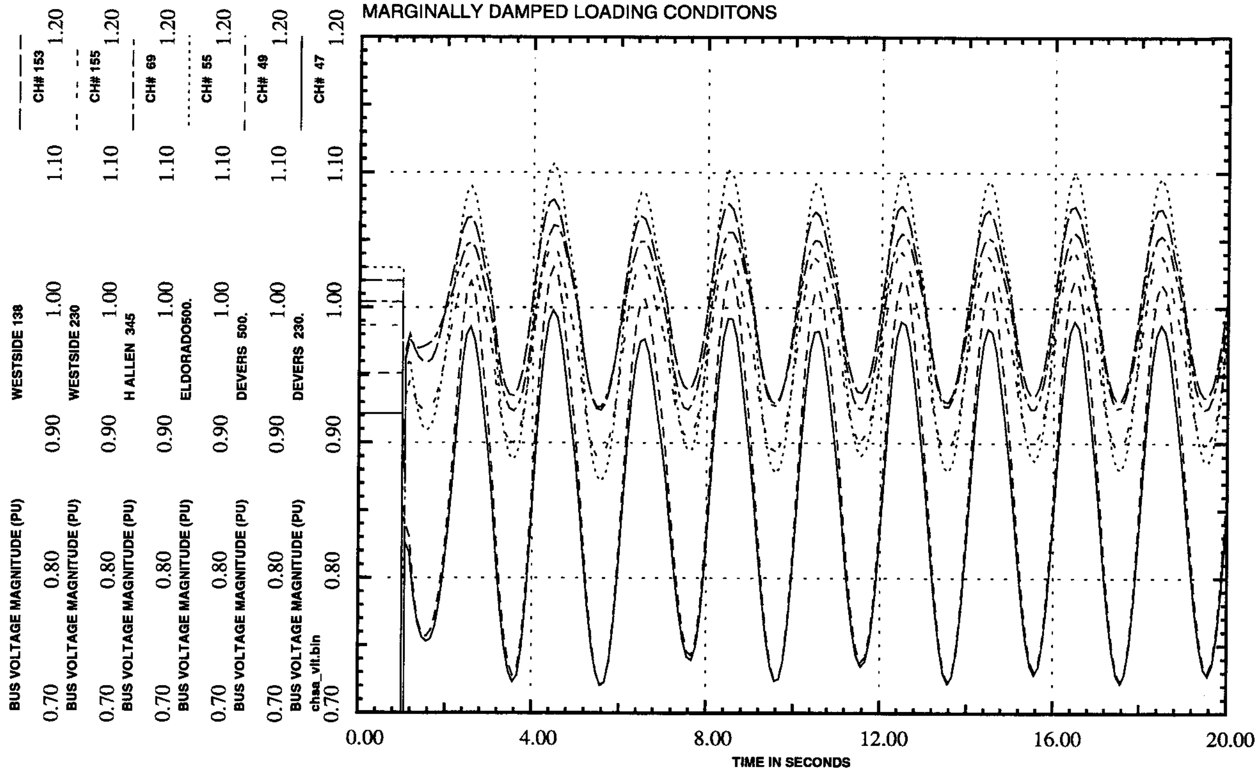
VOLTAGES LADWP (V9)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



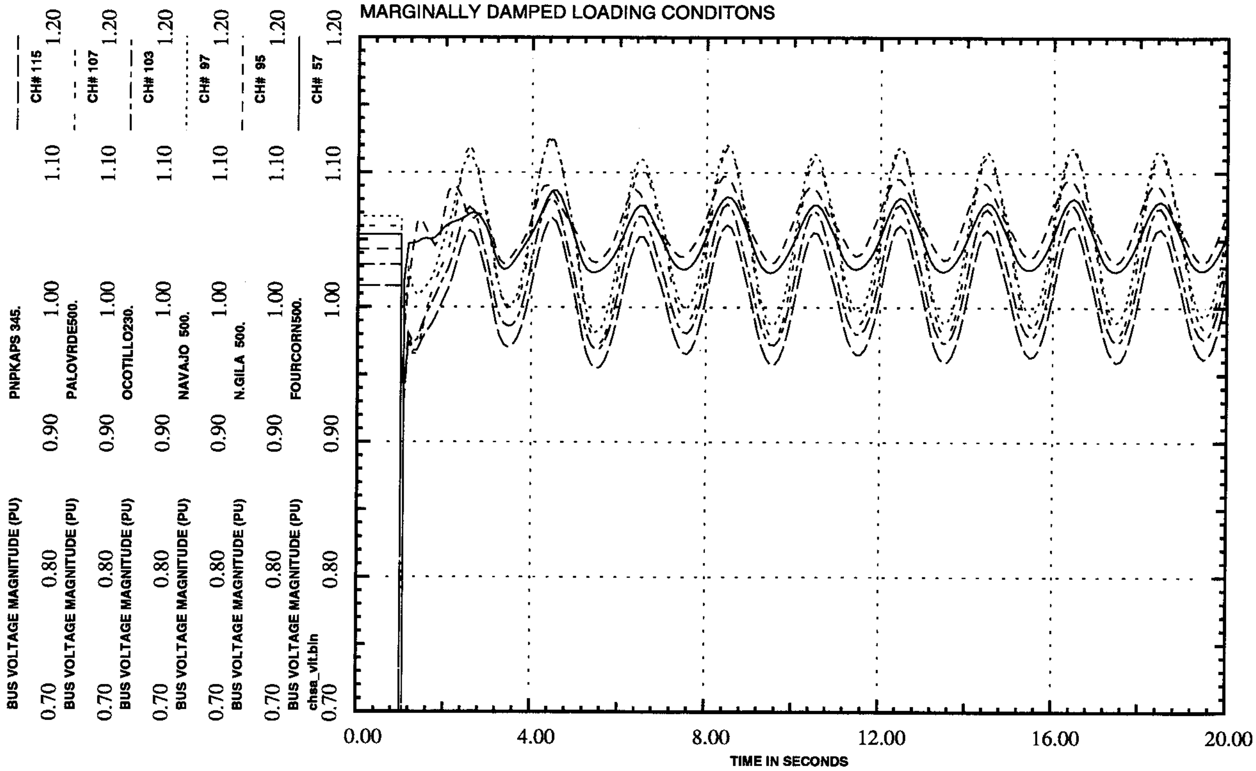
VOLTAGES COLO, NMEX (V10)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



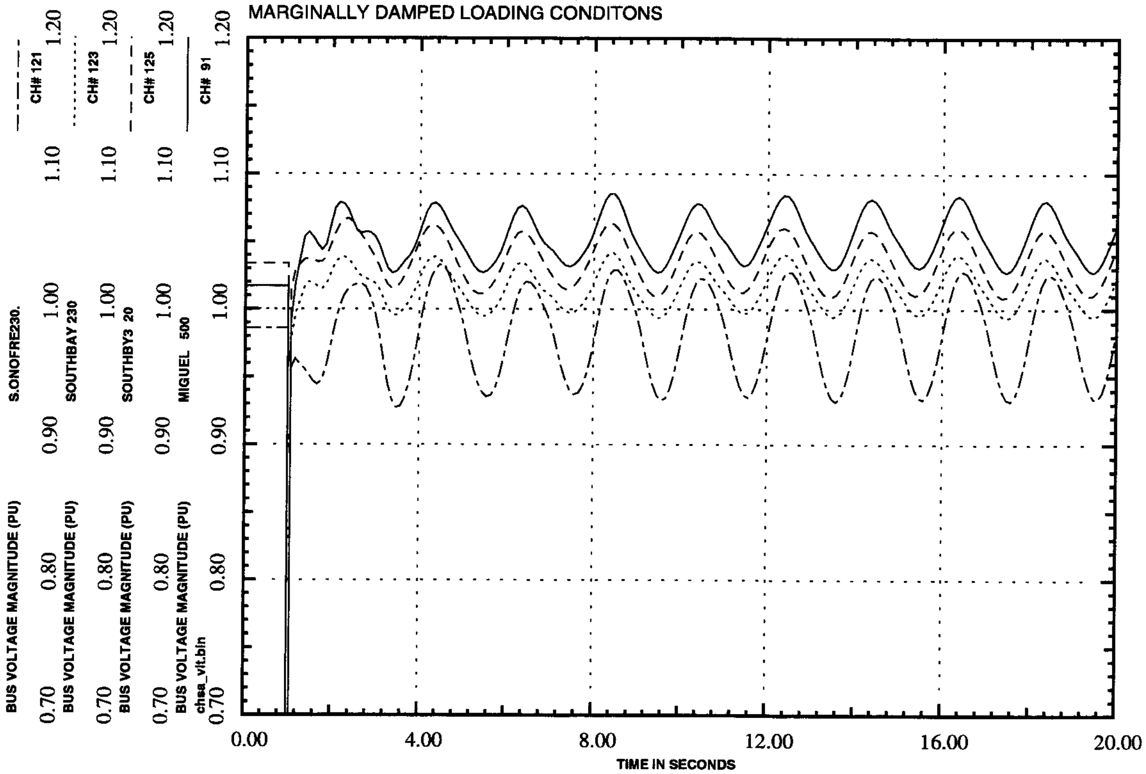
VOLTAGES SCE/NEVADA (V11)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



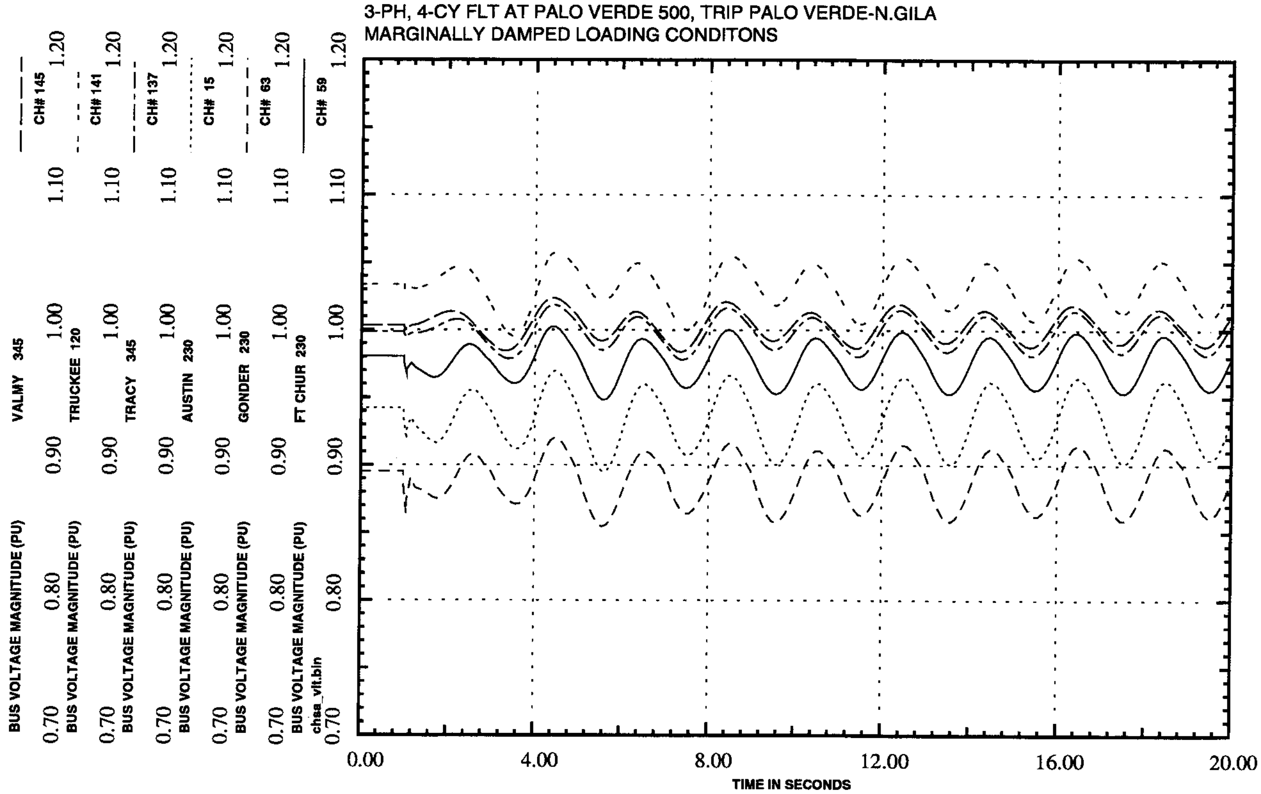
VOLTAGES ARIZONA (V12)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



VOLTAGES SCE/SDG&E (V13)

HSA Benchmark
1999 HEAVY SUMMER CASE
EOR=7020, WOR=9414, M/V=1968
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



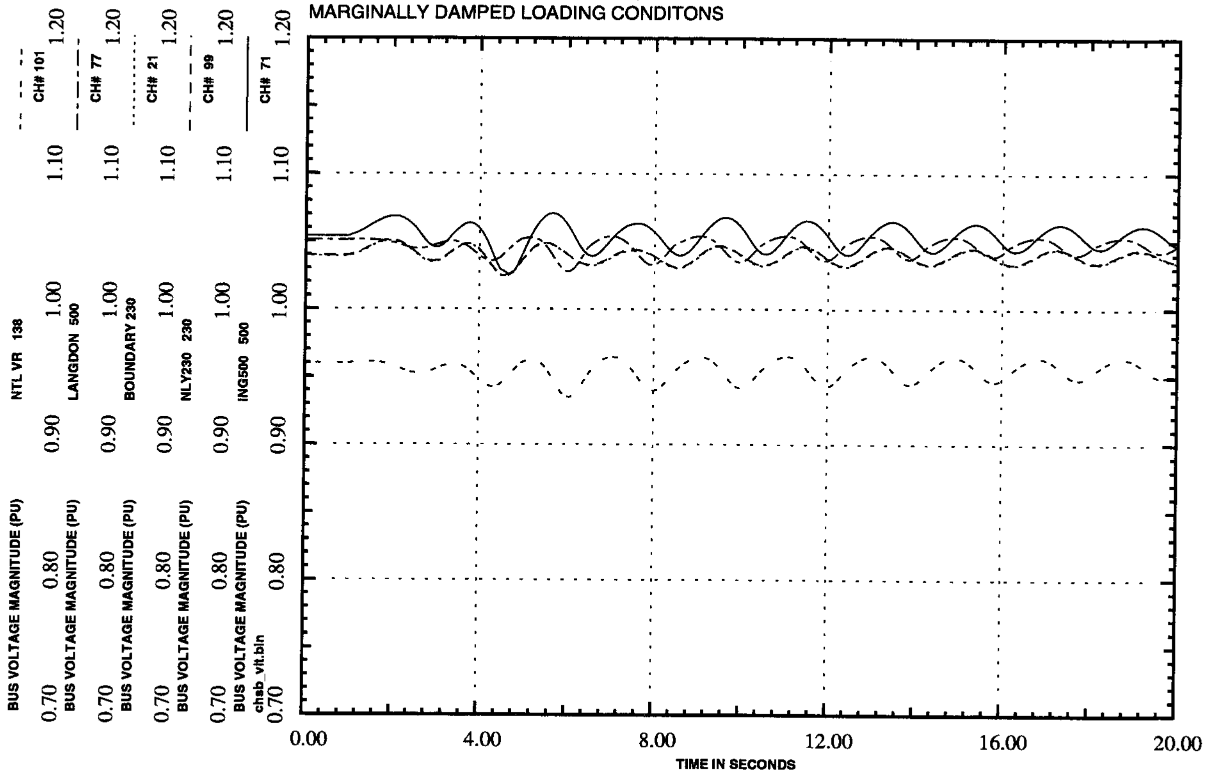
VOLTAGES SIERRA PAC. (V14)

APPENDIX B

Simulation Results for SCIT-2 Benchmark Loading Conditions

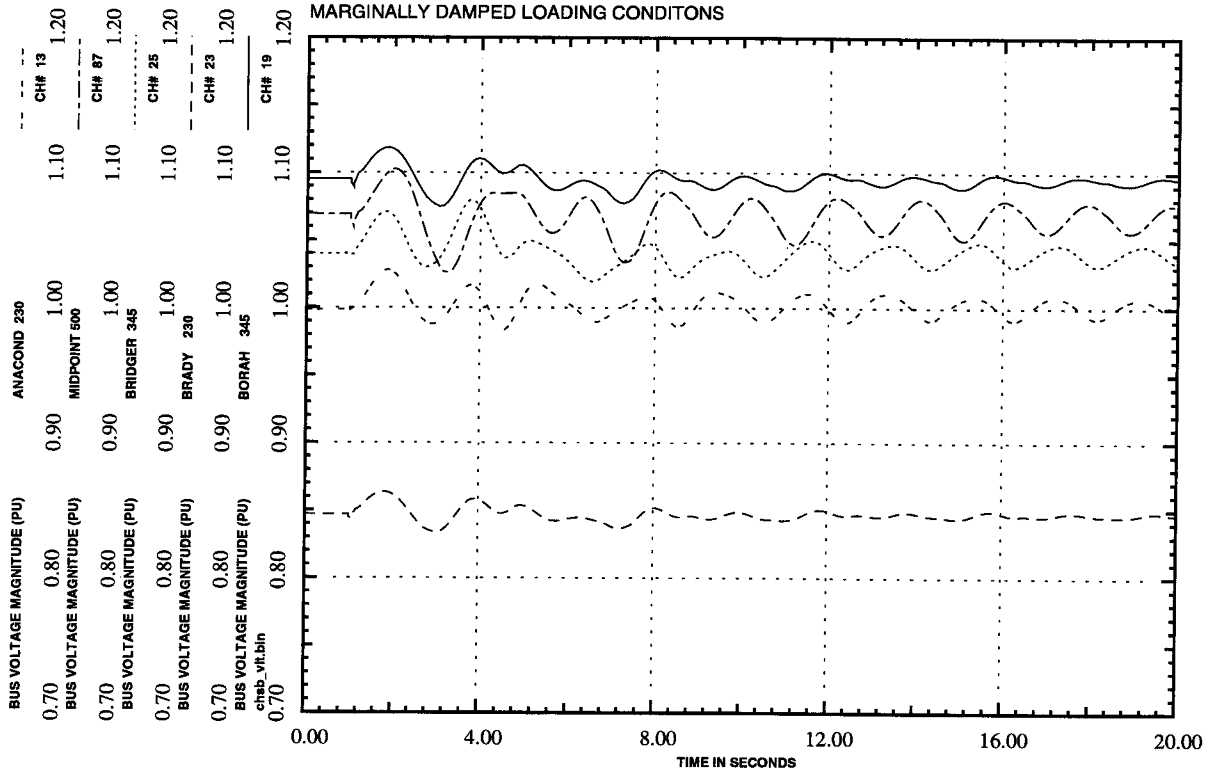
The following appendix contains ETMSP stability plots showing the simulated response to the Palo Verde-North Gila line outage contingency. Voltage magnitudes are plotted for buses in a given area, with 14 distinct groupings from throughout the system. A common voltage scale is used throughout all of the plots in this appendix.

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



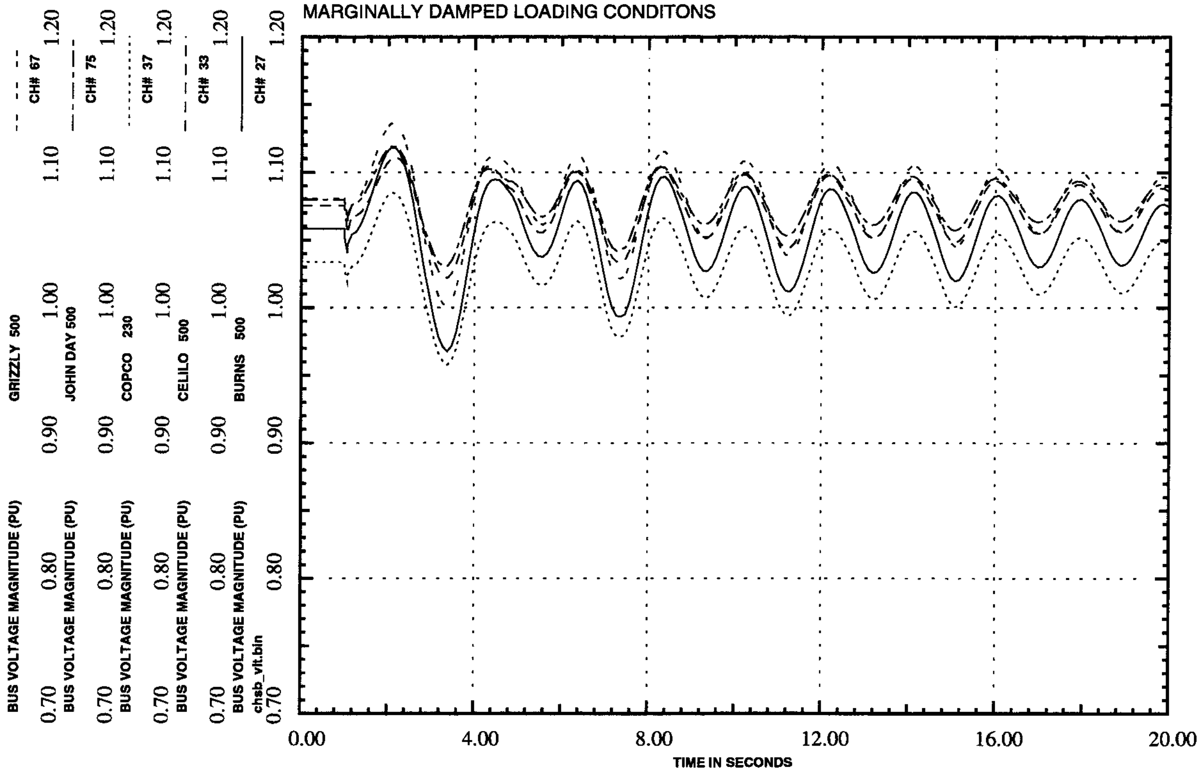
VOLTAGES NW, CANADA (V1)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



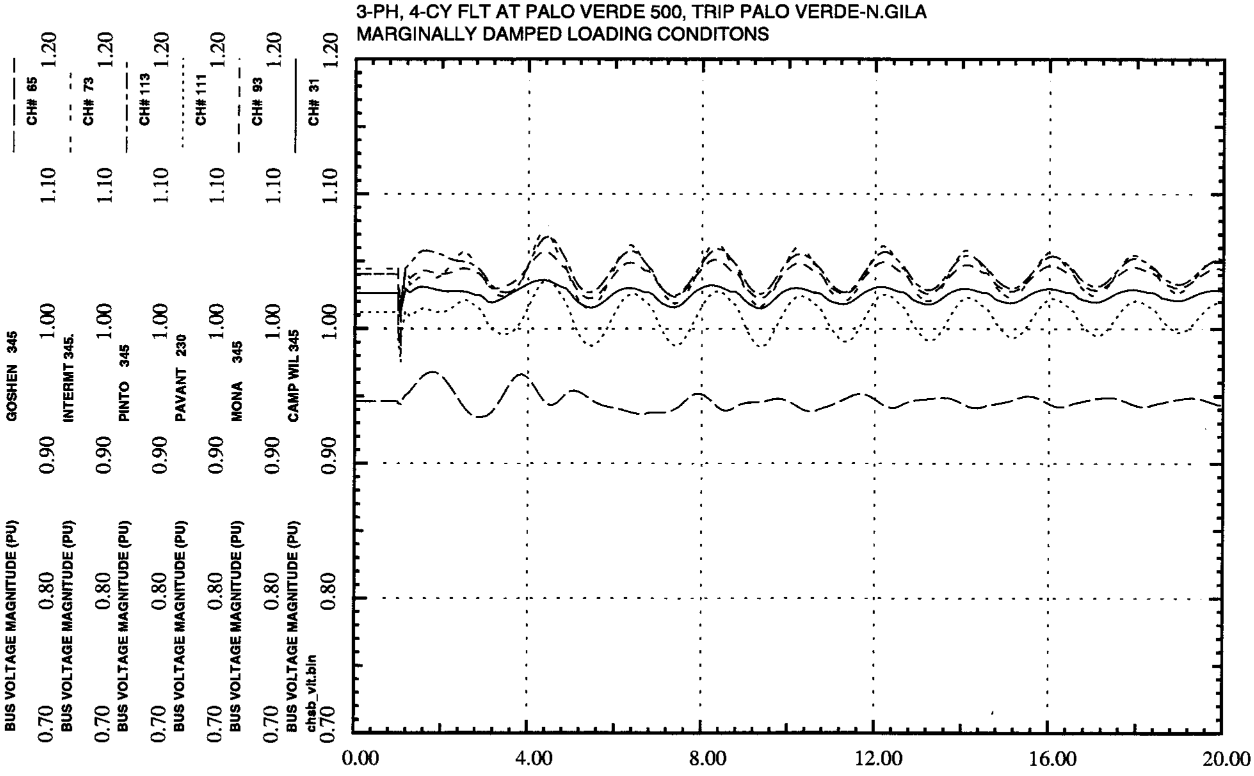
VOLTAGES IDAHO, MONT (V2)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



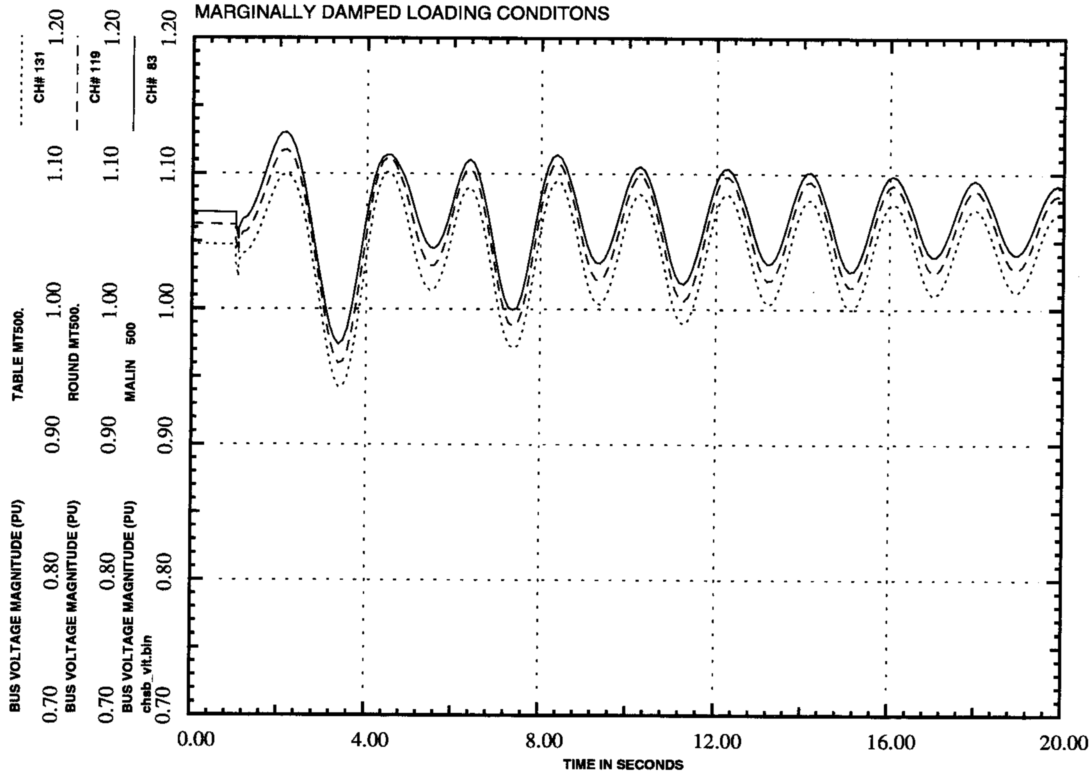
VOLTAGES NORTHWEST (V3)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



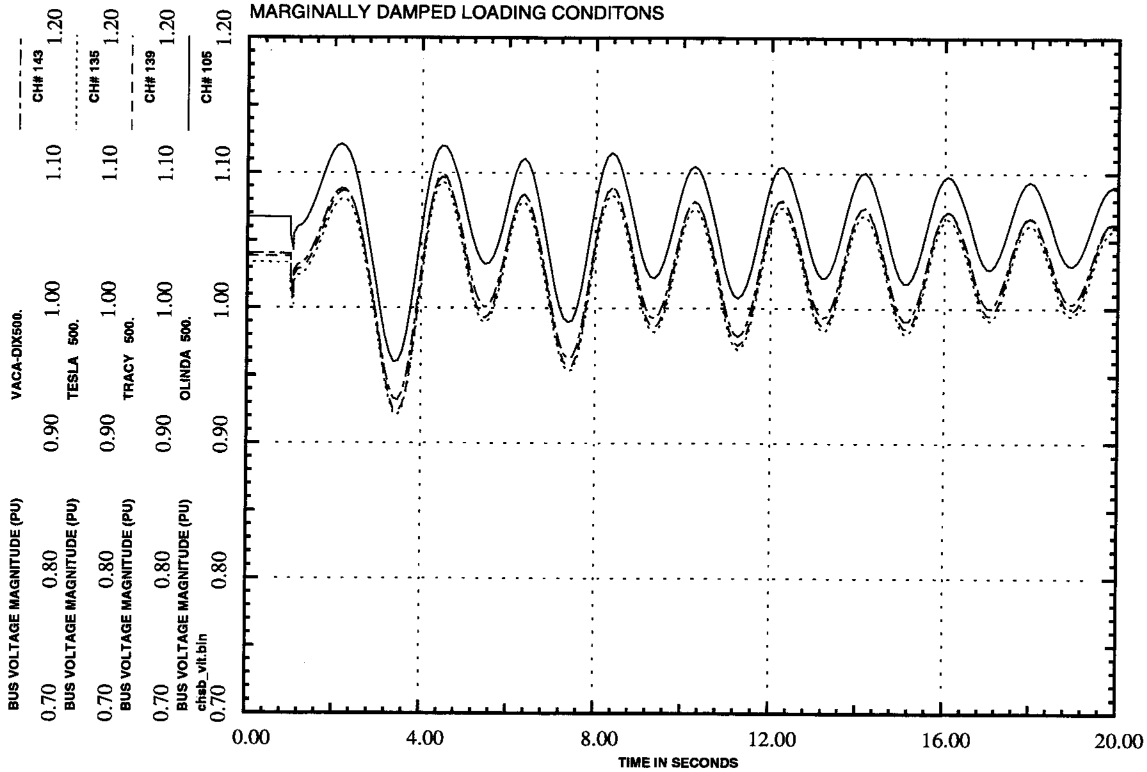
VOLTAGES UTAH (V4)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



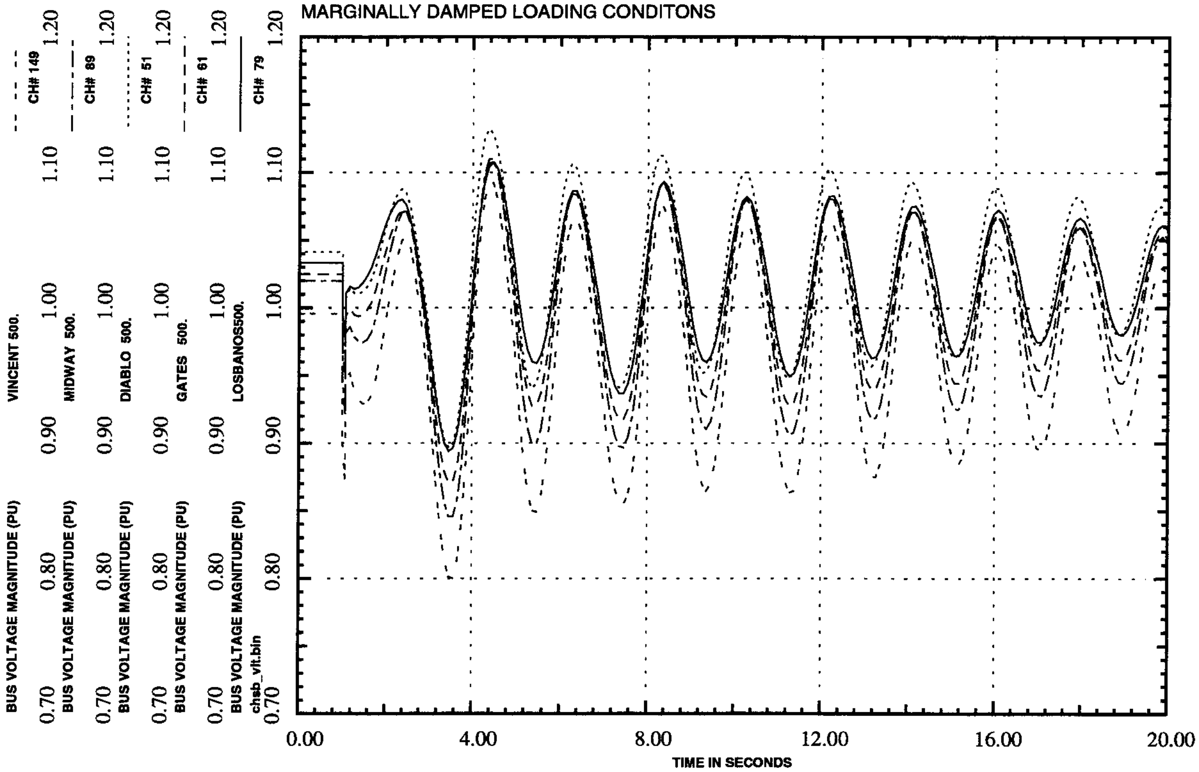
VOLTAGES PACI 1 (V5)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



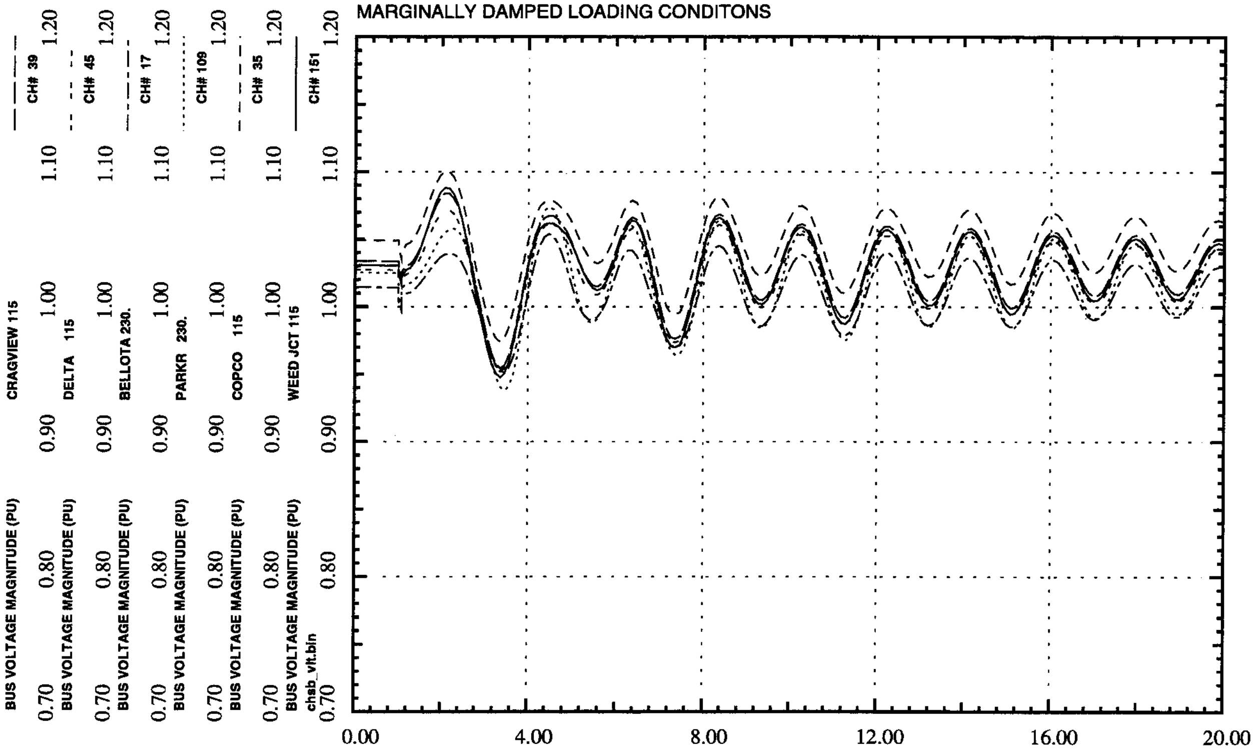
VOLTAGES PACI 2 (V6)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



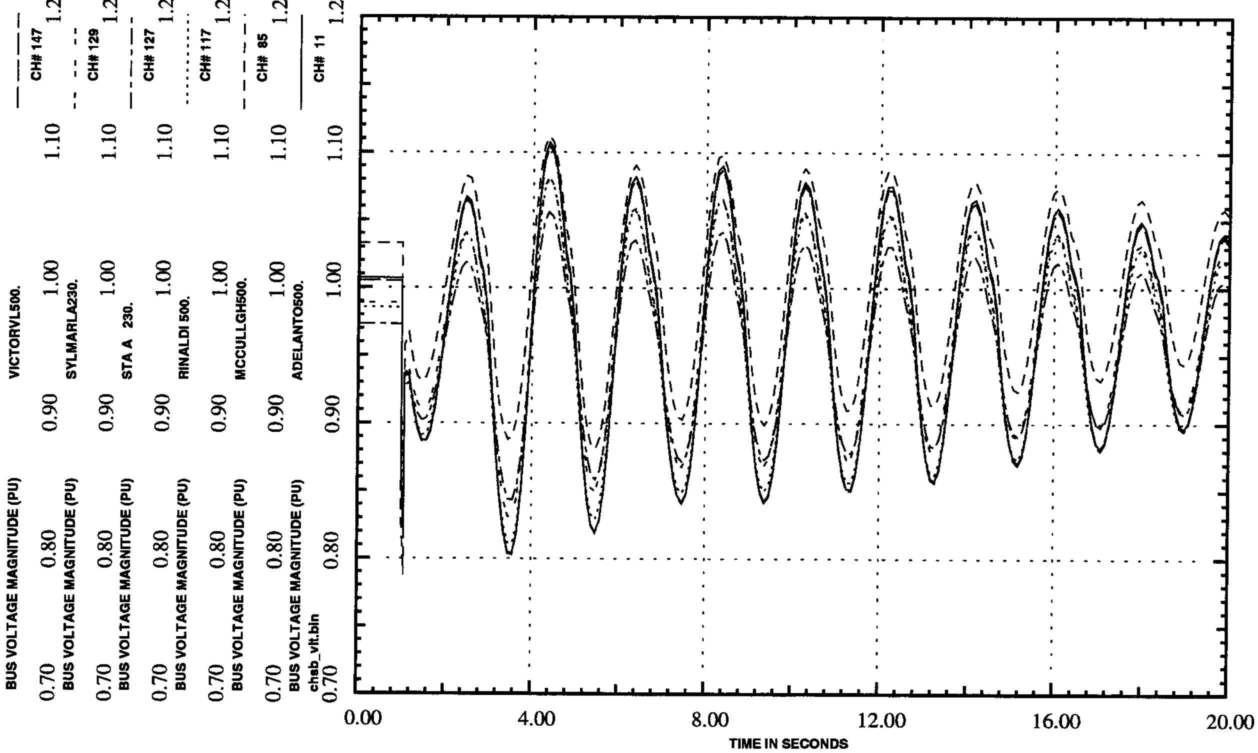
VOLTAGES PACI 3 (V7)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



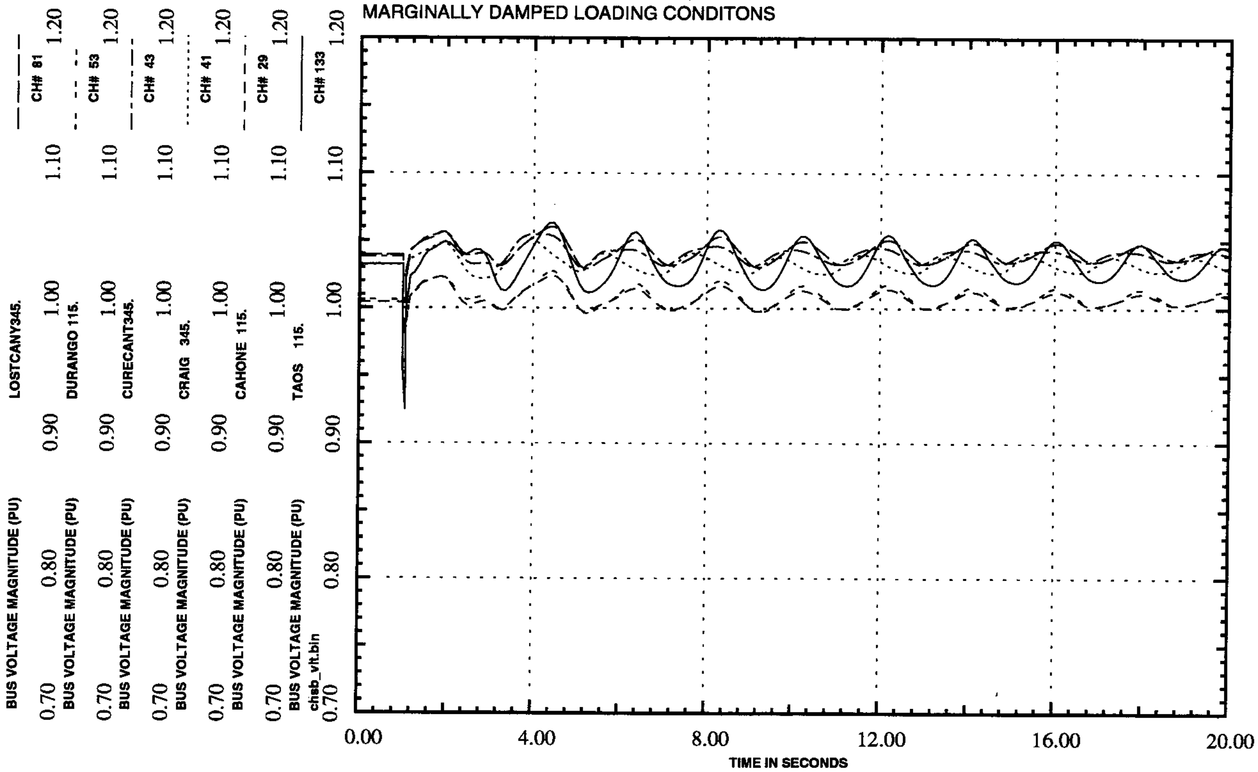
VOLTAGES MISC. (V8)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



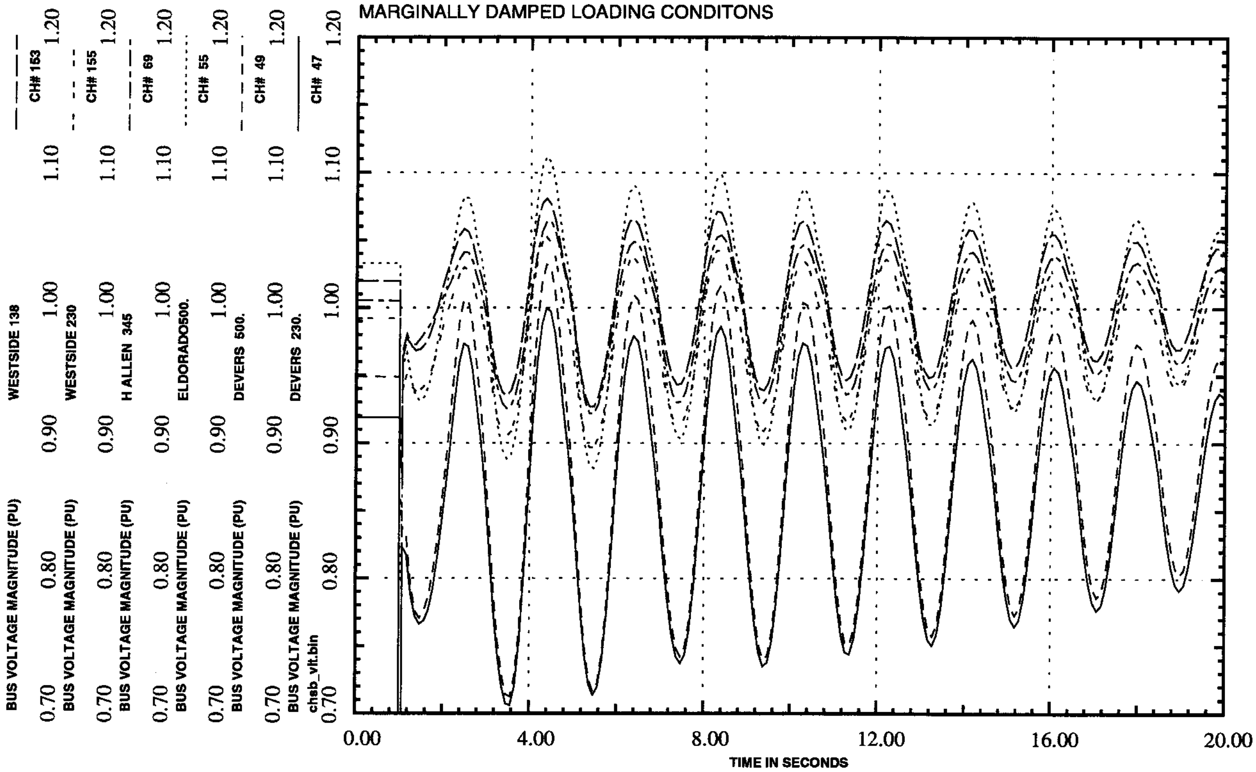
VOLTAGES LADWP (V9)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



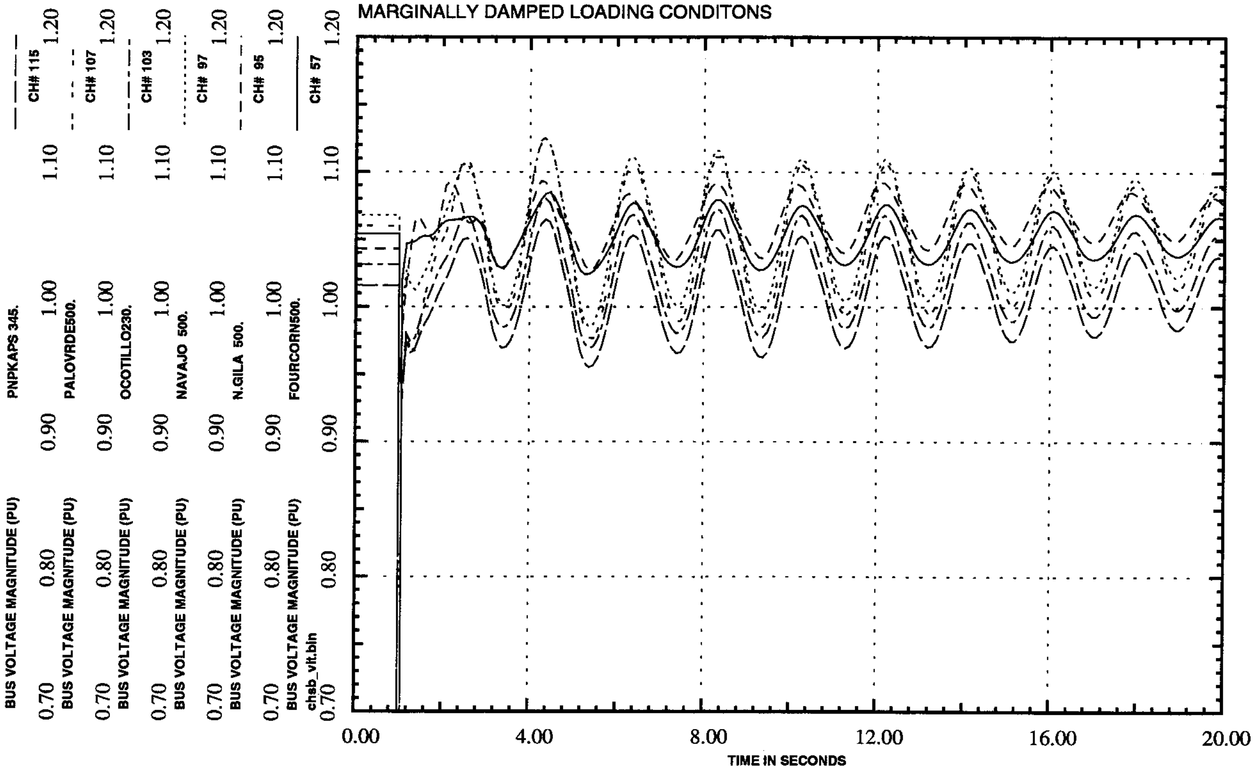
VOLTAGES COLO, NMEX (V10)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



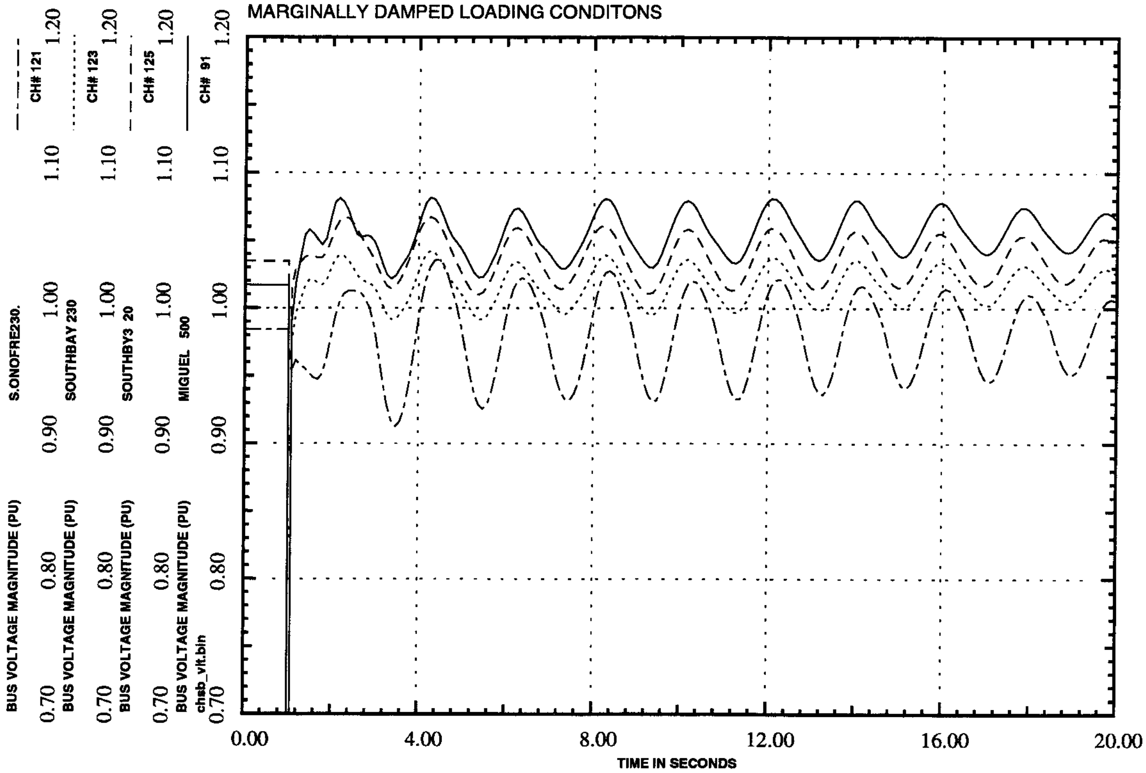
VOLTAGES SCE/NEVADA (V11)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



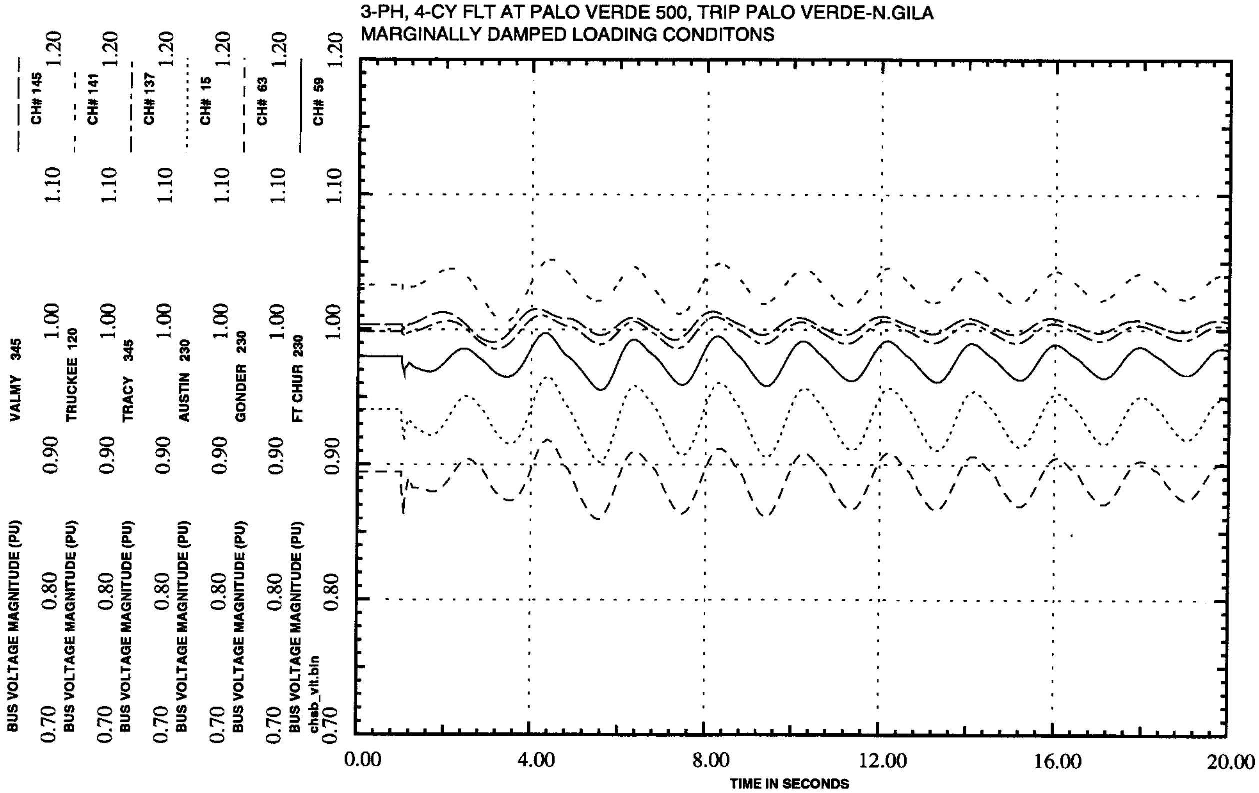
VOLTAGES ARIZONA (V12)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



VOLTAGES SCE/SDG&E (V13)

HSB Benchmark
1999 HEAVY SUMMER CASE
EOR=7007, WOR=8536, M/V=3612
3-PH, 4-CY FLT AT PALO VERDE 500, TRIP PALO VERDE-N.GILA
MARGINALLY DAMPED LOADING CONDITONS



VOLTAGES SIERRA PAC. (V14)

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