UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant,	**Docket Nos.**	**EL00-95-000 EL00-95-045 EL00-95-075**
v.		
Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.		
Investigation of Practices of the California Independent System Operator and the California Power Exchange		**EL00-98-000 EL00-98-042 EL00-98-063**

PREPARED TESTIMONY OF
GARY S. TARPLEE
ON BEHALF OF THE CALIFORNIA PARTIES

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-17
Privileged Info (Yes/No)	No
Document Title	Prepared Testimony of Gary S. Tarplee on Behalf of California Parties
Document Author	Gary S. Tarplee
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	AES/Williams, Duke, Dynegy, Mirant and Reliant placed units on "reserve shutdown" meaning that it shut the plant down for economic reasons when no maintenance was required, during times when the ISO had declared a system emergency. Seller withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001; c) after 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 and EL00-98 (including all subdockets)
Indicate if Material is New or from the Existing Record (include references to record material)	New
Explanation of what the evidence purports to show	The ISO FERC Electric Tariff that was in effect in 2000-2001, required generators who were connected to the ISO grid to meet all applicable Western Systems Coordinating Council (WSCC) standards. The WSCC (now the Western Electricity Coordinating Council) had in effect during this period Minimum Operating Reliability Criteria (MORC) that established the minimum criteria for operating reliability or procedures that are necessary for the secure and reliable operation of the interconnected power system. Other California Parties witnesses have testified that various generators

	withheld generation from the WSCC market in 2000 by placing units on reserve shutdown during many hours in which the units could have been sold at a profit or in which the ISO had declared system emergencies. During other hours, certain generators failed to bid or otherwise offer capacity from an available unit during times of high demand when the prices would have made sales economic and during which the ISO was in or near a system emergency. The ISO declared 32 emergencies from May 22, 2000 through September 30, 2000 due to operating reserve shortages, of which 14 resulted in load shedding. When emergency conditions existed in the ISO control area such that its system was operating below its minimum operating reserve criteria, the generators engaged in the withholding conduct described above were not in compliance with their obligations under the MORC, and therefore violated the ISO Tariff.
Party/Parties performing any alleged manipulation	AES/Williams, Duke, Dynegy, Mirant, Reliant

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PREPARED TESTIMONY OF
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Q. Please state your name, business address and occupation.

A. My name is Gary S. Tarplee. I am Manager, Grid Control for Southern California Edison Company (Edison). My business address is 501 S. Marengo Avenue, Alhambra, California 91803.

Q. Please summarize your education and professional background.

A. I received a Bachelor of Science Degree in Electrical and Electronic Engineering from California Polytechnic State University and a Master of Science Degree in Electrical Engineering specializing in power system planning and operations from the University of Southern California. After graduation, I spent seven years working for the Los Angeles Department of Water and Power in the System Planning and Operations organizations. I joined Edison in 1980, and held supervisory positions in Transmission Planning, Interconnection Planning, and Operating Engineering. In 1992, I became the Manager of the Energy Control Center (ECC). The ECC was responsible for SCE's control area operations including compliance with applicable regional reliability criteria. After the formation of the California Independent System Operator Corporation (ISO), the ECC became the Grid Control Center (GCC). The GCC serves as the company representative with the ISO on transmission and utility distribution company operations. It operates non-ISO controlled facilities and performs equipment/system rating studies, outage coordination, and new equipment operational planning.

Q. On whose behalf are you offering this testimony?

A. I am testifying on behalf of the California Parties, which are the People of the State of California *ex rel.* Bill Lockyer, Attorney General, the California Electricity Oversight Board, the California Public Utilities Commission, Pacific Gas and Electric Company, and Edison.

Q. What issues does your testimony address?

A. My testimony focuses on the Minimum Operating Reliability Criteria (MORC) that was in effect in the Western Systems Coordinating Council (WSCC) in 2000-2001, and on whether certain conduct of various generators who did business in the WSCC in that time period was in compliance with the MORC. My understanding is that the ISO FERC Electric Tariff that was in effect in 2000-2001, required generators who were connected to the ISO grid to meet all applicable WSCC standards.

Q. Please describe generally what the MORC contains and how it was developed.

A. The WSCC (now the Western Electricity Coordinating Council, or WECC) developed various standards to be used to assess and maintain the reliability of the interconnected system. These standards relate to such areas as system planning, power supply assessment, and operation of generation. The MORC are the WSCC standards relating to operations. They establish the minimum criteria for operating reliability or procedures that are necessary for the secure and reliable operation of the interconnected power system. These criteria are developed in accordance with specific procedures set forth by the WSCC.

Q. What is the basis for your familiarity with the MORC?

A. I have been Edison's representative on the WSCC Operating Committee (OC) since March of 2000. That year, the OC Chair appointed me to chair the Technical Operations Subcommittee (TOS), and I continue to hold that position. TOS has the responsibility for developing technical policies and guidelines for operating transmission, generation, and control areas. This includes policies on protective relays, generation control, substation operation, and maintenance. I also have served as a member of the WSCC's Compliance Monitoring and Operating Practices Subcommittee (CMOPS). As a member of CMOPS, my responsibilities included approving new operating practices and MORC revisions. I have been on several teams that review WSCC member compliance with the MORC. In addition, responsibility for Edison's compliance with most MORC and other WSCC policies rests in my organization.

Q. Other witnesses for the California Parties in this proceeding (Berry, Hanser, and Reynolds) have testified that various generators withheld generation from the WSCC market in 2000. Are you familiar with that testimony?

A. I understand that these witnesses present evidence showing that beginning in May of 2000, certain generators placed units on reserve shutdown during many hours in which the units could have sold at a profit or in which the ISO had declared system emergencies. I understand that there also is evidence showing that during other hours in that same time frame, certain generators failed to bid or otherwise offer capacity from an available unit during times of high demand when the prices would have made sales economic and during which the ISO was in or near a system emergency.

Q. What does it mean to place a unit in reserve shutdown?

A. Reserve shutdown is a state in which the unit was available for service but not electrically connected to the transmission system for economic reasons.

Q. What is a system emergency?

A. The ISO Tariff defines a system emergency as:

> Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.

Q. Did the ISO declare any system emergencies during the summer of 2000?

A. Yes. The ISO declared its first emergency for 2000 on May 22nd. By September 30th, it had declared 32 emergencies due to operating reserve shortages, of which 14 resulted in load shedding. I have included in Exh. No. CA-18 (Appendix A) at 1-3, a spreadsheet that we maintained in the Edison GCC to track emergencies and load shedding events in the ISO control area in 2000.

Q. If, in fact, generators engaged in the conduct that you have described, would that be in compliance with their obligations under the MORC?

A. No, it would not.

Q. What provisions of the MORC are implicated?

A. Section 1 of the MORC provides, in relevant part, that:

> All generation shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action will be

> taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

That section further states that there must be minimum operating reserves in each control area:

> The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies.

As I noted, in the summer of 2000, emergency conditions occurred in the ISO control area in which the minimum operating reserve criteria were not being met.

Q. Does the MORC prescribe procedures that are to be followed in the event of an emergency?

A. Yes. Section 5, entitled "Emergency Operations," provides such procedures. It states, among other things, that "[a]ll entities are expected to cooperate and take appropriate action to mitigate the severity or extent of any foreseeable system disturbance." A foreseeable system disturbance could be the loss of a transmission line or generator that would lower the amount of operating reserve available and cause the system to operate outside of the minimum generating reserve criteria in violation of the MORC. In fact, one of the specific emergency operations procedures is entitled "Reestablishing reserves" and provides that:

> Operating entities or control areas shall immediately take steps to reestablish reserves to protect themselves and ensure that loss of any subsequent element will not violate any operating limits.

> The time taken to restore resource operating reserves shall not exceed 60 minutes.

The MORC Emergency Operating procedures also require that "[t]he affected entity(ies) and control area(s) shall restore the interconnected power system to a secure and reliable state as soon as possible." I have included a copy of the August 2000 version of the MORC in Exh. No. CA-18 (Appendix B) at 4-31. The MORC provisions to which I refer in my testimony were identical to those in the previous version of the MORC and are unchanged in the current version.

Q. Please explain how the generators' withholding of generation would not be in compliance with those MORC provisions.

A. In the summer of 2000, when emergency conditions existed in the ISO control area such that its system was operating below its minimum operating reserve criteria, the MORC required "all entities . . . [to] take appropriate action to mitigate the severity or extent" of that situation and to "immediately take steps to reestablish reserves . . . ." It was at odds with those requirements for generators to have placed units on reserve shutdown at that point in time, or to have failed to bid capacity from units that were available at that time (and could have profitability sold electricity). Nor was the withholding of generation consistent with the requirement that "[a]ll generation . . . be operated to assure the highest practical degree of service reliability."

Q. Does that conclude your testimony?

A. Yes, it does.

AFFIDAVIT OF AUTHENTICATION

State of California)
Southern California Edison)
City of Rosemead)

Gary S. Tarplee, being first duly sworn, on oath says that he is the Gary S. Tarplee identified in the foregoing testimony; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Gary S. Tarplee

Gary S. Tarplee

Subscribed and sworn to before me on
this 24th day of February, 2003

Sophia Yang

NOTARY PUBLIC

SOPHIA YANG
Commission # 1284095
Notary Public — California
Los Angeles County
My Comm. Expires Dec 10,2004

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-18
Privileged Info (Yes/No)	No
Document Title	Appendices to Prepared Testimony of Gary S. Tarplee on Behalf of California Parties
Document Author	Gary S. Tarplee
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	AES/Williams, Duke, Dynegy, Mirant and Reliant placed units on "reserve shutdown" meaning that it shut the plant down for economic reasons when no maintenance was required, during times when the ISO had declared a system emergency. Seller withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
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ISO EVENT								INTERRUPTIBLE PROGRAM (MWs)												AREA LOAD CALCULATION (MWs)		
		No			Emergency Stage																	
Date		Touch	Alert	Warning	1	2	3	ACCP	API	I-6	I-6 Blocks									Peak	Interrupted	Avoided
											Z	Y	H	G	F	E	D	C	B			
Totals		73	32	84	55	36	1	12	22	21	16	15	15	16	16	16	16	16	16			
12/31/2000		X		X																11,069		
12/30/2000		X		X																11,405		
12/29/2000		X		X																12,490		
12/28/2000		X		X																12,835		
12/27/2000				X																12,854		
12/26/2000		X		X																12,439		
12/25/2000		X		X																10,170		
12/24/2000		X		X	X															11,158		
12/23/2000		X		X	X	X														11,828		
12/22/2000		X		X																12,942		
12/21/2000		X		X	X	X														13,506		
12/20/2000		X		X	X	X														13,695		
12/19/2000		X		X	X	X														13,815		
12/18/2000					X															13,732		
12/16/2000				X																12,220		
12/15/2000		X		X																13,293		
12/14/2000		X		X	X	X														13,777		
12/13/2000		X		X	X	X														13,859		
12/12/2000		X		X	X	X														13,945		
12/11/2000		X		X	X	X														13,885		
12/10/2000		X		X	X	X														12,183		
12/9/2000		X		X	X	X														12,258		
12/8/2000		X		X	X	X														13,260		
12/7/2000	pm	X		X	X	X	X		46	859	X	X	X	X	X	X	X	X	X	12,670	905	13,090
12/7/2000	am								46	250	X	X	X	X	X	X	X	X	X		296	
12/6/2000		X	X	X	X	X			46	846	X	X	X	X	X	X	X	X	X	12,945	892	13,837
12/5/2000		X		X	X	X			46	923	X	X	X	X	X	X	X	X	X	12,810	969	13,835
12/4/2000		X		X	X	X			46	843	X	X	X	X	X	X	X	X	X	13,327	889	13,947
12/3/2000				X																12,342		
12/1/2000				X																13,554		
11/30/2000				X																13,802		
11/29/2000				X																13,767		
11/28/2000				X																13,775		
11/27/2000		X																		13,761		
11/22/2000		X		X																13,162		
11/21/2000		X		X																13,408		

11/20/2000		X	X	X	X	X																13,409		
11/19/2000				X	X																	11,728		
11/18/2000				X																		11,777		
11/17/2000		X	X	X																		13,087		
11/16/2000		X	X	X	X																	13,499		
11/15/2000		X	X	X	X	X				46	785	X	X	X	X	X	X	X	X	X		12,826	831	13,259
11/14/2000		X		X	X	X				46	575			X	X	X	X	X	X	X		12,860	621	13,359
11/13/2000				X	X	X				46	748	X	X	X	X	X	X	X	X	X		12,829	794	13,623
9/20/2000		X	X	X	X																	15,919		
9/19/2000		X	X	X	X																	17,278		
9/18/2000		X	X	X	X	X			185	46	942	X	X	X	X	X	X	X	X	X		17,860	1,173	18,650
9/17/2000				X																		16,853		
9/16/2000				X	X																	17,890		
9/15/2000		X	X	X																		18,606		
9/14/2000		X		X	X	X																18,486		
9/13/2000		X		X	X	X			179	46	396	X	X						X	X		18,402	621	18,954
9/12/2000				X	X																	18,780		
9/11/2000				X																		17,103		
8/26/2000				X	X																	15,614		
8/25/2000				X	X																	17,194		
8/24/2000		X		X																		17,511		
8/23/2000		X																				17,511		
8/22/2000				X	X																	16,755		
8/19/2000				X																		16,134		
8/18/2000		X	X	X																		18,305		
8/17/2000		X	X	X	X	X																19,343		
8/16/2000		X	X	X	X	X			189	46	956	X	X	X	X	X	X	X	X	X		19,757	1,191	19,845
8/15/2000		X		X	X	X			185	46	307					X	X	X				19,039	538	19,146
8/14/2000		X	X	X	X	X			185	46	574	X	X	X	X				X	X		18,722	805	18,844
8/13/2000		X																				15,917		
8/12/2000		X																				17,132		
8/11/2000		X	X		X	X																19,382		
8/10/2000				X																		18,717		
8/9/2000				X																		17,891		
8/7/2000		X		X																		17,252		
8/6/2000		X	X																			15,193		
8/5/2000		X		X																		17,136		
8/4/2000		X	X	X	X																	18,501		
8/3/2000		X	X	X	X	X																18,777		
8/2/2000		X	X	X	X	X			186	46	1051	X	X	X	X	X	X	X	X	X		17,810	1,283	18,275
8/1/2000		X	X	X	X	X			195	46	982	X	X	X	X	X	X	X	X	X		18,045	1,223	19,338
7/31/2000		X	X	X	X	X			189	46	905	X	X	X	X	X	X	X	X	X		17,717	1,140	18,562
7/28/2000				X	X																	18,065		

7/26/2000		X																				18,137		
7/25/2000		X	X	X	X																	18,371		
7/24/2000		X	X	X	X																	18,280		
7/20/2000		X	X	X	X																	18,796		
7/19/2000		X	X		X	X			204	46	374				X	X	X	X				18,784	624	19,094
7/18/2000				X																		18,184		
6/29/2000		X	X	X	X																	17,888		
6/28/2000		X	X	X	X	X			176	46	148			X								17,749	370	18,098
6/27/2000		X	X	X	X	X			194	46	245	X	X									18,160	485	18,544
6/26/2000		X		X	X	X			194	46												18,247	240	18,487
6/22/2000		X																				16,739		
6/21/2000				X																		16,667		
6/16/2000		X																				15,869		
6/15/2000		X	X	X																		17,702		
6/14/2000		X	X	X	X																	17,777		
6/13/2000		X	X		X																	17,492		
5/23/2000		X	X	X																		14,334		
5/22/2000	pm	X	X	X	X	X				46	567							X	X	X		16,159	613	16,527
5/22/2000	am									46	37				X	X	X						83	
5/21/2000		X																				14,361		

Western Systems Coordinating Council

AUGUST 2000

RELIABILITY CRITERIA

MINIMUM OPERATING RELIABILITY CRITERIA

PART III

WESTERN SYSTEMS COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

TABLE OF CONTENTS

WESTERN SYSTEMS COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

INTRODUCTION

The reliable operation of the Western Interconnection requires that all entities comply with the *Western Systems Coordinating Council (WSCC) Minimum Operating Reliability Criteria* (hereafter referred to as MORC). The MORC shall apply to system operation under all conditions, even when facilities required for secure and reliable operation have been delayed or forced out of service.

On a continuing basis, the North American Electric Reliability Council (NERC), through its Operating Committee, establishes, reviews, and updates operating criteria to be followed by individual entities, pools, coordinated areas and reliability councils. All entities, WSCC members and nonmembers, shall operate in accordance with the NERC or WSCC Reliability Criteria, whichever is more specific or stringent. In addition to complying with the MORC, all entities shall comply with all WSCC Operating Policies and Procedures which are included in the *WSCC Operations Committee Handbook*. The WSCC shall periodically review and revise MORC in accordance with the guidelines set forth in the *WSCC Reliability Criteria Part V – Process for Developing and Approving WSCC Standards.*

NERC has identified control areas as the primary entities responsible for ensuring the secure and reliable operation of the interconnected power system. Secure and reliable operation can only result from all entities complying with a consistent set of operating criteria. To this end it is imperative for all control areas in the Western Interconnection to be members of the WSCC. Entities such as Independent System Operators and Area Security Coordinators may assume some of the responsibilities that control areas have traditionally held. It is also imperative that these entities be WSCC members and comply with all operating reliability criteria which apply to control areas.

The MORC and all WSCC Operating Policies and Procedures apply to all entities unless expressly stated as applying only to a particular entity. It is imperative that all entities equitably share the various responsibilities to maintain reliability. Examples of equitably sharing reliability responsibilities include, but are not limited to:

- proper coordination and communication of interchange schedules,
- participation in coordinated underfrequency load shedding programs,
- participation in the unscheduled flow mitigation plan,
- providing appropriate levels of power system stabilizers, and
- maintaining appropriate governor droop settings.

The MORC is divided into sections corresponding to the NERC Policies. Also included are the coordination requirements necessary to achieve the objectives set forth in these Criteria. It is emphasized that these are minimum criteria related to operating reliability or procedures which are necessary for the secure and reliable operation of the interconnected power system.

More specific and more stringent operating reliability criteria may be developed by each individual entity, pool, and/or coordinated area within the WSCC.

Section 1 - Generation Control and Performance

All generation shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action will be taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

A. Operating Reserve

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- supply requirements for load variations.
- replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
- meet on-demand obligations.
- replace energy lost due to curtailment of interruptible imports.

1. **Minimum operating reserve.** Each control area shall maintain minimum operating reserve which is the sum of the following:

    (a) **Regulating reserve.** Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's *Control Performance Criteria.*

    Plus (b) **Contingency reserve.** An amount of spinning and nonspinning reserve, sufficient to meet the Disturbance Control Standard as defined in 1.E.2(a). This Contingency Reserve shall be at least the greater of:

    (1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or

    (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve).

    For generation-based reserves, only the amount of unloaded generating capacity that can be loaded within ten minutes of notification can be considered as reserve.

    Plus (c) **Additional reserve for interruptible imports.** An amount of reserve, which can be made effective within ten minutes following notification, equal to interruptible imports.

Plus (d) **Additional reserve for on-demand obligations.** An amount of reserve, which can be made effective within ten minutes following notification, equal to on-demand obligations to other entities or control areas.

2. **Acceptable types of nonspinning reserve.** The nonspinning reserve obligations identified in A.1.b, A.1.c, and A.1.d, if any, can be met by use of the following:

   (a) interruptible load

   (b) interruptible exports

   (c) on-demand rights from other entities or control areas

   (d) spinning reserve in excess of requirements in A.1.a and A.1.b

   (e) off-line generation which qualifies as nonspinning reserve (see definition)

3. **Knowledge of operating reserve.** Operating reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.

4. **Restoration of operating reserve.** After the occurrence of any event necessitating the use of operating reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes.

5. **Analysis of islanding potential.** Each entity or coordinated group of entities shall analyze its potential for islanding in total or in part from interconnected resources at least every three years and shall maintain appropriate additional operating reserve for such contingencies or, if such is impractical, its load and generation shall be balanced by other appropriate measures.

6. **Sharing operating reserves.** Under written agreement, the operating reserve requirements of two or more control areas may be combined or shared, providing that such combination, considered as a single control area, meets the obligations of paragraph A.1. Similarly, arrangements may be made whereby one control area supplies a portion of another's operating reserve, provided that such capacity can be made available in such a manner that both meet the requirements of paragraph A.1. A firm transmission path must be available and reserved for the transmission of these operating reserves from the control area supplying the reserves to the control area calling on them.

7. **Operating reserve distribution.** Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements. Spinning reserve should be distributed to maximize the effectiveness of governor action.

8. **Review of contingencies.** To determine the amount of operating reserve required, contingencies shall be frequently reviewed and the most severe contingency designated.

B. Automatic Generation Control

Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load. It shall also provide its proper contribution to Interconnection frequency regulation.

1. **Inclusion in control area.** Each entity operating transmission, generation, or distribution facilities shall either operate a control area or make arrangements to be included in a control area operated by another entity. All generation, transmission, and load operating within the Western Interconnection shall be included within the metered boundaries of a WSCC control area. Control areas are ultimately responsible for ensuring that the total generation is properly matched to total load in the Interconnection.

2. **AGC.** Prudent operating judgment shall be exercised in distributing control among generating units. AGC shall remain in operation as much of the time as possible. As described in the *WSCC Guidelines for Suspending Automatic Generation Control* in the *WSCC Operations Committee Handbook*, AGC suspension should be considered when AGC equipment has failed or if system conditions could be worsened by AGC.

3. **Familiarity with AGC equipment.** Control center operating personnel must be thoroughly familiar with AGC equipment and be trained to take necessary corrective action when equipment fails or misoperates. If primary AGC has become inoperative, backup AGC or manual control shall be used to adjust generation to maintain schedules.

4. **Data scan rates for ACE**. It is recommended that the periodicity of data acquisition for and calculation of ACE should be no greater than four seconds.

C. Frequency Response and Bias

1. **Frequency bias setting.** The frequency bias shall be set as close as possible to the control area's natural frequency response characteristic. In no case shall the annual frequency bias or the monthly average frequency bias be set at a value of less than 1% of the estimated control area annual peak load per 0.1 Hz change in frequency.

2. **Governors.** To provide an equitable and coordinated system response to load/generation imbalances, governor droop shall be set at 5%. Governors shall not be operated with excessive deadbands, and governors shall not be blocked unless required by regulatory mandates.

3. **Tie-line bias.** Each control area shall operate its AGC on tie-line frequency bias mode, unless such operation is adverse to system or Interconnection reliability.

D. Time Control

1. **Time error.** Control areas shall assist in maintaining frequency at or as near 60.0 Hz as possible and shall cooperate in making any necessary time corrections per the *WSCC Procedure for Time Error Control.* The amount of continuous time error contribution is a function of control area time error bias, inadvertent interchange accumulation, and the time error.

2. **Maintain standards for frequency offset.** Control areas shall cooperate in maintaining standards established by the NERC Operating Committee for frequency offset to make time corrections manually.

3. **Time error correction notice and commencement.** Time error corrections shall start and end on the hour or half hour, and notice shall be given at least twenty minutes before the time error correction is to start or stop. Time error corrections shall be made at the same rate by all control areas.

4. **Calibration of time and frequency devices.** Each control area shall at least annually check and calibrate its time error and frequency devices against a common reference.

E. Control Performance

1. **Continuous monitoring.** Each control area shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.

   (a) **Control performance standard (CPS1).** Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β (β is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ε, is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee.

   (b) **Control performance standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See NERC's *Performance Standard Training Document*, Section B.1.1.2 for the methods for calculating L_{10}.

   (c) **Control performance standard (CPS) compliance.** Each control area shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90%.

2. **Disturbance conditions.** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions (see the *Performance Standard Training Document*, Section B.2):

   (a) **Disturbance Control Standard.** Following the start of a disturbance, the ACE must return either to zero or to its pre-disturbance level within the time specified in the Disturbance Control Standard currently in effect in NERC Policy 1.

(b) **Disturbance control standard compliance.** Each control area or reserve sharing group shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances.

(c) **Reportable disturbance reporting threshold.** Each control area or reserve sharing group shall include events that cause its Area Control Error (ACE) to change by the lesser of 300 MW or 80% of its Most Severe Single Contingency.

(d) **Average percent recovery.** For each reportable disturbance, the control area(s) with a MW loss or participating in the response, such as through operating reserve obligations or through a reserve sharing group, shall calculate an Average Percent Recovery. A copy of the control area's calculations, ACE chart, and Net Tie Deviation from Schedule chart shall be submitted to the NERC Regional Performance Subcommittee representative not later than 10 calendar days after the reportable disturbance.

(e) **Contingency reserve adjustment factor.** The WSCC Performance Work Group (PWG) shall determine the Contingency Reserve Adjustment Factor for each control area no later than April 20, July 20, September 20, and January 20 for the previous quarter. The local PWG representatives shall allocate the factor among control areas that are members of reserve sharing groups according to the allocation methods developed by the group.

(f) **Operating reserve for control areas and reserve sharing groups.** Minimum Operating Reserve shall be increased by the Contingency Reserve Adjustment Factor. The WSCC Performance Work Group shall monitor the compliance of each control area and reserve sharing group for carrying the minimum required operating reserve.

3. **ACE values.** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

F. Inadvertent Interchange

1. **Hourly verification.** Each control area shall, through hourly schedule verification and the use of reliable metering equipment, accurately account for inadvertent interchange.

2. **Common metering.** Each control area interconnection point shall be equipped with a common kWh meter, with readings provided hourly at the control centers of both areas.

3. **Including all interconnections.** All interconnections shall be included in inadvertent interchange accounting. Interchange served through jointly owned

facilities and interchange with borderline customers shall be properly taken into account.

G. Control Surveys

1. **Survey purpose.** Periodic surveys of the control performance of the control areas shall be conducted. These surveys reveal control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

2. **Surveys.** The control areas in the Western Interconnection shall perform each of the following surveys, as described in the *NERC Control Performance Criteria Training Document*, when called for by the NERC Performance Subcommittee:

   (a) **AIE survey.** Area Interchange Error survey to determine the control area's interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

   (b) **FRC survey.** Area Frequency Response Characteristic survey to determine the control area's response to changes in system frequency.

   (c) **CPC survey.** Control Performance Criteria survey to monitor the control area's control performance during normal and disturbance situations.

H. Control and Monitoring Equipment

1. **Tie line bias control equipment.** Each control area shall use accurate and reliable automatic tie line bias control equipment as a means of continuously balancing actual net interchange with scheduled net interchange, plus or minus its frequency bias obligation and automatic time error correction. The power flow and ACE signals that are transmitted for regulation service shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.

2. **Tie flows in ACE calculation.** To achieve accurate control, each control area shall include all of its interconnecting ties in its ACE calculation. Common interchange metering equipment at agreed upon terminals shall be used by adjacent control areas.

3. **Control checks made each hour.** Actual interchange shall be verified each hour by each control area using tie line kWh meters to determine regulating performance. Adjacent control areas shall use the same MWh value for each common interchange point. Control settings shall be adjusted to compensate for any equipment error until equipment malfunction can be corrected.

I. Backup Power Supply

Under emergency conditions, adequate and reliable emergency or backup power supply must be available to provide for generating equipment protection and continuous operation of those facilities required for restoration of the system to normal operation.

1. **Safe shut-down power.** Emergency or auxiliary power supply shall be provided for the safe shutdown of thermal generating units when completely isolated from a power source.

2. **Reliable start-up power.** A reliable and adequate source of start-up power for generating units shall be provided. Where sources are remote from the generating unit, standing instructions shall be issued to expedite start up.

3. **Black start capability for critical generating units.** All control areas must identify critical generating units and ensure provision of "black start" capability for these units if appropriate arrangements have not been made to receive off-system power for the purpose of system restoration.

4. **Testing.** Emergency or backup power supplies shall be periodically tested to ensure their availability and performance.

Section 2 - Transmission

The interconnected power system shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action shall be taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

A. Transmission Operations

1. **Basic criteria.** The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood (as defined below). Entities must ensure this criteria is met under all system conditions including equipment out of service, equipment derates or modifications, unusual loads and resource patterns, and abnormal power flow conditions. A single contingency means the loss of a single system element, however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood. When experience proves that an outage involving multiple system elements, AC or DC, occurs more than once during the previous three years and causes, on other systems, loss of load, loss of generation rated greater than 100 MW or cascading outages, it shall be treated as a single contingency.

   When it is agreed that a disturbance on specific facilities occurs more often than should be reasonably expected and results in an undue burden on the transmission system, the owners of the facilities shall take measures to reduce the frequency of occurrence of the disturbance, and cooperate with other entities in taking measures to reduce the effects of such disturbance.

   Continuity of service to load is the primary objective of the *Minimum Operating Reliability Criteria*. Preservation of interconnections during disturbances is a secondary objective except when preservation of interconnections will minimize the magnitude of load interruption or will expedite restoration of service to load.

It is undesirable for the loss of load to exceed the amount of load designed to be tripped. This applies to all levels of system underfrequency load shedding programs, undervoltage load tripping schemes or other controlled remedial actions. It applies whether the initiating disturbance occurs within or outside the affected system. Entities may be required to establish maximum import levels to meet these criteria. The necessary operating procedures, equipment, and remedial action schemes shall be in place to prevent unplanned or uncontrolled loss of load or total system shutdown.

2. **Joint reliability procedures.** Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3. **Phase-shifting transformers and other flow altering facilities.** Phase shifting transformers or other facilities, when used to alter power flow through the interconnected power system, shall be operated to control the actual power flow within the limits of the scheduled power flow and the unaltered power flow. In meeting the criteria, a tolerance of two taps on phase shifting transformers and one discrete increment on other noncontinuous controllable devices is permissible provided no other operating criteria are violated. Such power flow altering facilities may be operated to some other criteria provided agreement is reached among the affected parties.

4. **Protective relay reliability.** Relays that have misoperated or are suspected of improper operation shall be promptly removed from service until repaired or correct operation is verified.

B. Voltage and Reactive Control

1. **Maintaining service.** To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled, adequate reactive reserves shall be provided, and adequate transmission system voltages shall be maintained.

2. **Providing reactive requirements.** Each entity shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

3. **Coordination.** Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4. **Transmission lines.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly make notification according to the *WSCC Procedure for Coordination of Scheduled Outages and Notification of Forced Outages* when removing such facilities from and returning them back to service

5. **Generators.** Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the host control area. The control mode of generating units shall be accurately represented in operating studies.

6. **Automatic voltage control equipment.** Automatic voltage control equipment on generating units, synchronous condensers, and static var compensators shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the host control area operator.

7. **Power system stabilizers.** Power system stabilizers on generators and synchronous condensers shall be kept in service as much of the time as possible.

8. **Reactive reserves.** Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

9. **Undervoltage load shedding.** Operating entities shall assess the need for and install undervoltage load shedding as required to augment other reactive reserves to protect against voltage collapse and ensure system reliability performance criteria as specified in the WSCC Disturbance-Performance Table of Allowable Effect on Other Systems are met during all internal and external outage conditions. The operator shall have written authority to manually shed additional load if necessary to maintain acceptable voltages and/or sufficient reactive margin to protect against voltage collapse.

10. **Switchable devices.** Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

11. **HVDC.** Entities with HVDC transmission facilities should use the reactive capabilities of converter terminal equipment for voltage control.

Section 3 - Interchange

To ensure the secure and reliable operation of the interconnected power system, all entities involved in interchange scheduling shall coordinate and communicate information concerning schedules and schedule changes accurately and timely as detailed in the *WSCC Scheduling Procedures for All Entities Involved in Interchange Scheduling.*

A. Interchange

1. **Net schedules.** The net schedule on any control area to control area interconnection or transfer path within a control area shall not exceed the total transfer capability of the transmission facilities.

2. **Transfer capability.** Transmission providers or control areas shall determine normal total transfer capability limits for the delivery and receipt of scheduled interchange. The determination of such total transfer capability limits shall, as far as practicable, take into consideration the effect of power flows through other parallel systems or control areas under both normal operating conditions and with a single contingency outage of the most critical facility.

3. **Schedule confirmation and implementation.** All scheduled transactions shall be confirmed and implemented between or among the control areas involved in such transactions. "Control areas involved" means the control area where the schedule originates, the control area(s) providing transmission service for the transaction, and the control area where the scheduled energy is delivered. If a schedule cannot be confirmed it shall not be implemented.

4. **Schedule verification.** Control areas shall verify the net scheduled interchange with adjacent control areas on a preschedule and hourly real-time basis. Such real-time verification shall take place prior to the start of the ramp.

5. **Schedule changes.** Schedule changes must be coordinated between control areas to ensure that the schedule changes will be executed by all control areas at the same time, in the same amount and at the same rate.

6. **Type of transaction.** Parties providing and receiving the scheduled energy shall agree upon the type of transaction being implemented (firm or interruptible) and the control area(s) and other parties providing the operating reserve for the transaction, and shall make this information available to all control areas involved in the transaction.

7. **Information sharing.** Control areas, pools, coordinated areas or reliability councils shall develop procedures to disseminate information on schedules which may have an adverse effect on other control areas not involved in making the scheduled power transfer.

8. **Unscheduled flow.** Unscheduled flow is an inherent characteristic of interconnected AC power systems and the mere presence of unscheduled flow on circuits other than those of the scheduled transmission path is not necessarily an indication of a problem in planning or in scheduling practices. WSCC transmission paths experiencing significant curtailments as a result of unscheduled flow may be qualified for unscheduled flow relief under the *WSCC Unscheduled Flow Reduction Procedure*. All personnel involved in

interchange scheduling shall be trained and fully competent in implementing the *WSCC Unscheduled Flow Reduction Procedure.*

The WSCC planning process and the *Unscheduled Flow Reduction Procedure* are designed to minimize impact of unscheduled flow for normal system configurations. During abnormal system configurations such as during the restoration period following a major system disturbance, consideration shall be given to the unscheduled flow effects created by schedules and scheduled transmission paths and the security coordinator(s) shall ensure that all schedules are arranged such that the effect of unscheduled flow does not cause transfer capability limits to be exceeded on other transmission paths.

It is unacceptable to rely on opposing unscheduled flow to keep actual flows within the path total transfer capability regardless of whether the path is a transmission element internal to a control area or whether the path is a control area to control area interconnection.

B. Transfer Capability Limit Criteria

The total transfer capability limit is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- An interconnection from one control area to another control area; or
- A transfer path within a control area.

The net schedule and prevailing actual power flowing over an interconnection or transfer path within a control area shall not exceed the total transfer capability limit on the interconnection or transfer path.

1. **Operating limits.** No elements within the interconnection shall be scheduled above continuous operating limits. An element is defined as any generating unit, transmission line, transformer, bus, or piece of electrical equipment involved in the transfer of power within an interconnection. At all times the interconnected system shall be operated so neither the net scheduled or actual power transferred over an interconnection or transfer path shall exceed the total transfer capability of that interconnection or transfer path. If the limit is exceeded, immediate action shall be taken to reduce actual flow to within transfer capability limits within 10 minutes for stability limitations and within 30 minutes for thermal limitations.

2. **Stability.** The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the *WSCC Reliability Criteria for Transmission System Planning.* If a single event could cause loss of multiple elements, these shall be considered in lieu of a single element outage. This could occur in exceptional cases such as two lines on the same right-of-way next to an airport. In either case, loss of either single or multiple elements should not cause uncontrolled, widespread collapse of the interconnected power system.

3. **System contingency response.** Following the outage and before adjustments can be made:

   (a) No remaining element shall exceed its short-time emergency rating.

   (b) The steady-state system voltages shall be within emergency limits.

The limiting event shall be determined by conducting power flow and stability studies while simulating various operating conditions. These studies shall be updated as system configurations introduce significant changes in the interconnection.

Section 4 - System Coordination

A high degree of coordination is essential within and between the entities, control areas, pools and coordinated areas of the WSCC in all phases of operation which can affect the reliability of the interconnected power system.

This section sets forth operating items that require coordination to make certain that the minimum operating reliability criteria contained herein can be realized by the interconnected power system.

A. Monitoring System Conditions

Coordination and communication in the following areas is essential for secure and reliable operation of the interconnected power system.

1. **System conditions.** Loads, generation, transmission line and bulk power transformer loading, voltage, and frequency shall be monitored as required to determine if system operation is within known safe limits under both normal and emergency situations.

2. **Deviations.** The use of automatic equipment to bring immediate attention to important deviations in system operating conditions and to indicate or initiate corrective action shall be implemented.

3. **Remedial action scheme status alarms.** Alarms shall be provided to alert operating personnel regarding the status of remedial action schemes which are under their direct control and impact the reliability and security of interconnected power system operation.

4. **Sharing operational information.** All entities shall, by mutual agreement, provide essential and timely operational information regarding their system (e.g., line flows, generator status, net interchange schedules at tie points, etc.) to all affected transmission providers and control areas.

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

B. Coordination with Other Entities

1. **Procedures.** Procedures shall be in place for the effective transfer of operating information between control areas, entities, and coordinated groups of entities as necessary to maintain interconnected power system reliability.

2. **Switching operation.** The opening or closing of interconnections between control areas, and the opening or closing of any lines internal to control areas which may affect the operation of the interconnected power system under normal and emergency conditions must be fully coordinated.

3. **Voltage and reactive flows.** Control areas shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions. All operating entities shall assist with their control area's coordination efforts.

4. **Load shedding and restoration.** The shedding and restoration of loads in emergencies must be coordinated as described in detail in Sections 5.D. and 6.C.

5. **Automatic actions.** Any automatic controlled islanding and automatic generator tripping which is necessary to maintain interconnected power system stability under emergency conditions shall be coordinated. All automatic remedial actions (automatic bypass of series compensation, phase shifter runback, opening of lines or transformers, load tripping, etc.) which may impact the interconnected power system, shall be coordinated.

6. **Interconnection capabilities.** Information regarding the operating capabilities of interconnecting facilities between operating entities or control areas shall be exchanged routinely and all operating entities shall coordinate establishment of the operating limitations of these facilities under normal and emergency conditions.

7. **Plans and forecasts.** Information regarding short-term load forecasts, generating capabilities, and schedules of additions or changes in system facilities that could affect interconnected operation shall be routinely disseminated.

8. **System characteristics.** Information regarding system electrical characteristics that affect the operation of the interconnected system, including any significant changes which result from the addition of facilities or modification of existing facilities, shall be routinely disseminated.

9. **Operating reserve.** Information regarding operating reserve policies and procedures shall be routinely disseminated.

10. **Abnormal operating conditions.** Operating entities forced to operate in such a way that a single contingency could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse, shall promptly notify WSCC and other affected operating entities via the WSCC Communication System.

11. **Notification of system emergencies.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WSCC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

12. **Notification of noncompliance.** If an operating entity is not able to comply with the condition and term of a particular criterion, it must notify the host control area. The control area operator will notify the WSCC who will report the noncompliance to the NERC Operating Committee.

C. Maintenance Coordination

1. **Sharing information.** The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

D. System Protection Coordination

Reliable and adequate relaying must be provided to protect and permit maximum utilization of generation, transmission and other system facilities.

1. **Coordination.** Information regarding protective relay systems affecting interconnected operation shall be routinely disseminated and the settings of such relays shall be coordinated with the affected entities.

2. **Reviewing settings.** Relay applications and settings shall be reviewed periodically and adjustments made as needed to meet system requirements.

3. **Testing.** Each operating entity shall periodically test protective relay systems and remedial action schemes which impact the security and reliability of interconnected power system operation.

Section 5 - Emergency Operations

Even though precautionary measures have been developed and utilized, and extensive protective equipment installed, emergencies of varying magnitude do occur on the interconnected power system. These emergencies may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, and interruption of customer service. All entities are expected to cooperate and take appropriate action to mitigate the severity or extent of any foreseeable system disturbance. Those operating criteria relating to emergency operation are set forth in this section.

A. Emergency Operating Philosophy

During an emergency condition, the security and reliability of the interconnected power system are threatened; therefore, immediate steps must be taken to provide relief. The following operating philosophy shall be observed:

1. **Corrective action.** The entity(ies) experiencing the emergency condition shall take immediate steps to relieve the condition by adjusting generation, changing schedules between control areas, and initiating relief measures including manual or automatic load shedding (if required) to relieve overloading or

imminent voltage collapse. ACE shall be returned to zero or to its predisturbance value within the time specified in the Disturbance Control Standard following the start of a disturbance.

2. **Written authority.** Dispatching personnel shall have full responsibility and written authority to implement the emergency procedures listed in 5.A.1. above.

3. **Reestablishing reserves.** Operating entities or control areas shall immediately take steps to reestablish reserves to protect themselves and ensure that loss of any subsequent element will not violate any operating limits. The time taken to restore resource operating reserves shall not exceed 60 minutes.

4. **Notifying other affected entities.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WSCC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

5. **AGC.** AGC shall remain in service as long as its action continues to be beneficial. If AGC is out of service, manual control shall be used to adjust generation. AGC shall be returned to service as soon as practicable.

6. **Prompt restoration.** The affected entity(ies) and control area(s) shall restore the interconnected power system to a secure and reliable state as soon as possible.

7. **Zeroing schedules.** Energy schedules on a transmission path shall be promptly reduced to zero following an outage of the path unless a backup transmission path has been pre-arranged. If a system disturbance results in system islanding, all energy schedules across open paths between islands shall be immediately reduced to zero unless doing so would prolong frequency recovery.

8. **Emergency total transfer capability limits.** Emergency total transfer capability limits shall be established which will permit maintaining stability with voltage levels, transmission line loading and equipment loading within their respective emergency limits in the event another contingency occurs.

9. **Adjustments following loss of resources.** Following the loss of a resource within a control area, scheduled and actual interchange shall be re-balanced within the time specified in the Disturbance Control Standard following the loss of a resource within a control area. Following the loss of a remote resource or curtailment of other interchange being scheduled into a control area with no backup provisions, the energy loss shall be immediately reflected in the control area's ACE and corrected within the time specified in the Disturbance Control Standard.

B. Coordination with Other Entities

1. **Emergency outages.** Information regarding emergency outages of facilities, the time frame for restoration of these facilities, and the actions taken to mitigate the effects of the outages must be exchanged promptly with other affected entities.

2. **Voltage collapse.** Information regarding problems that could lead to voltage collapse shall be disseminated to other affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

3. **Other affecting conditions.** Information regarding violent weather disturbances or other disastrous conditions which could affect the security and reliability of the interconnected power system shall be disseminated to all affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

4. **Single contingency exposure.** All affected entities shall be notified promptly via the WSCC Communication System by any entity forced to operate in such a way that a single contingency outage could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse. Entities not connected to the WSCC Communication System shall make this notification through their host control area.

5. **Emergency support personnel.** All control areas shall arrange for technical and management support personnel to be available 24 hours per day to provide coordination support in the event of system disturbances or emergency conditions. These personnel shall be on call to coordinate collecting and sharing of information. Each control area shall develop procedures in coordination with the Security Coordinators and the WSCC office to fulfill this support responsibility. The Security Coordinators shall expedite communication of appropriate information to the WSCC office during system disturbances and emergency operating conditions to enable the WSCC office to coordinate the reporting of information pertaining to the entire western region to federal agencies, regulatory bodies, and the news media in a timely manner. Management support personnel shall maintain close and timely communication with the WSCC office during extreme emergency conditions or system disturbances of widespread significance in the Western Interconnection.

C. Insufficient Generating Capacity

1. **Capacity or energy shortages**

   (a) A control area experiencing capacity or energy shortages after exhausting all possible assistance from entities within the control area shall immediately request assistance from adjacent control areas or entities. Neighboring control areas shall be notified as to the amount of the capacity or energy shortages. Neighboring control areas shall make every effort to provide all available assistance.

(b) If inadequate relief is obtained from (a) above, then,

(1) Procedures outlined in the *WSCC Procedure for Securing Emergency Assistance* shall be implemented.

(2) Control area(s) shall initiate relief measures as required to maintain reserves.

2. **Deficient control area.** A control area is considered deficient when:

- all available generating capacity is loaded, and
- all operating reserve is utilized, and
- all interruptible load and interruptible exports have been interrupted, and
- all emergency assistance from other control areas is fully utilized, and
- the ACE is negative and cannot be returned to zero in the time specified in the Disturbance Control Standard.

In this case, it will be necessary to manually shed firm load without delay to return the ACE to zero.

3. **Manual load shedding.** Through written standing orders and instructions the system dispatchers shall be given clear authority to implement manual load shedding without consultation whenever, in their judgment, such immediate action is necessary to protect the reliability and integrity of the system. Manual load shedding may also be required to restore system frequency which has stabilized below 60 Hz or to avoid an imminent separation which would produce a severe deficiency of power supply in the affected area. Upon system separation or islanding, manual load shedding may be required to restore system frequency which has stabilized below 60 Hz.

D. Restoration

Following a major disturbance which may require load shedding, sectionalizing, or generator tripping, immediate steps must be taken to return the system to normal.

Extreme care must be exercised to avoid prolonging or compounding the emergency. While each disturbance will be different and may require different dispatcher action, the criteria set forth in the following subsections will provide the general guidelines to be observed. It is imperative that dispatchers maintain close coordination with neighboring dispatchers during restoration as follows:

1. **Extent of island.** Determine the extent of the islanded area or areas. Take any necessary action to restore area frequency to normal, including adjusting generation, shedding load and synchronizing available generation with the area.

The following is a checklist of items to be communicated to determine any action required prior to reconnecting systems following a major disturbance:

(a) Determine the condition of your own system:

(1) Separation points

(2) Overloaded ties

(3) Power flows

(4) Condition of generation

(5) Load shed

(b) Contact immediate neighbors to determine their condition:

(1) Effect of the disturbance on them.

(2) Their separation points.

(3) Can a tie be made to them which will help your system or will help their system?

(4) The amount of their or your system to be paralleled or picked up.

(5) The relative speeds of the two systems and the potential impacts of closing the tie.

(6) Overload conditions or potential overloads to be made worse or better by the tie.

(7) The voltage difference between the two systems that must be corrected by shedding load, adjusting generation or connecting reactive equipment before the tie is closed.

(c) Determine the best tie to be made among neighbors. Proceed to make the tie as recommended in the *WSCC Interconnection Disturbance Assessment and Restoration Guidelines* in the OC Handbook.

2. **Start-up power.** Prior to restoring large customer loads, provide start-up power to generating stations and off-site power to nuclear stations where required. Adjacent entities shall establish mutual assistance arrangements for start-up power to expedite prompt restoration.

3. **Synchronizing areas.** As soon as voltage, frequency and phase angle permit, synchronize the islanded area with adjacent areas, using extreme caution to avoid unintentionally synchronizing large interconnected areas through relatively weak lines.

4. **Restoring loads.** Loads which have been shed during a disturbance shall only be restored when system conditions have recovered to the extent that those loads can be restored without adverse effect. If loads are reconnected by manual means or by supervisory control, they shall be restored only by direct action or order of the dispatcher, as generating capacity becomes available and transmission ties are reconnected. Loads shall not be manually restored until sufficient generating resources are available to return the ACE to zero within ten minutes. If automatic load restoration is used, it shall comply with the *WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration*

Plan and any other more stringent local program established in thorough coordination with neighboring systems and designed to avoid the possibility of recreating underfrequency, overloading ties, burdening neighboring systems, or delaying the restoration of ties. Relays installed to restore load automatically shall be set with varying and relatively long time delays, except in those cases where automatic load restoration is designed to protect against frequency overshoot.

E. Disturbance Reporting

Information and experience gained from studying disturbances which affect the operation of the interconnected power system are helpful in developing improved operating techniques.

1. **Disturbance analysis.** Entities and coordinated groups of entities within the WSCC shall establish procedures and responsibility for collecting, analyzing and disseminating information and data concerning major disturbances. To facilitate post disturbance analyses, oscillographic and event recording equipment shall be installed at all key locations and synchronized to National Institute of Standards and Technology time.
2. **Recommendations.** Recommendations for eliminating or alleviating causes and effects of disturbances shall be made when appropriate.

F. Sabotage Reporting

Each operating entity or control area shall establish procedures for recognizing and reporting unusual occurrences suspected or determined to be acts of sabotage. These procedures shall cover recognizing acts of sabotage, disseminating information regarding such acts to the appropriate persons or entities within the area or within the interconnected power system, and notifying the appropriate local or regional law enforcement agencies.

Section 6 - Operations Planning

Each operating entity and coordinated group of operating entities is responsible for maintaining, and implementing as required, a set of current plans which are designed to evaluate options and set procedures for secure and reliable operation through a reasonable future time period. This section specifies requirements for operations planning to maintain the security and reliability of the interconnected power system.

A. Normal Operations

1. **Operating studies.** Studies conducted to obtain information which identifies operating limitations affecting transmission capability, generating capability, other equipment capability and power transfers between transmission providers or control areas shall be coordinated. To be considered acceptable, operating study results must be in compliance with the WSCC Disturbance-Performance Table within the *WSCC Reliability Criteria for Transmission System Planning.*
2. **Transfer limits under outage and abnormal system conditions.** In addition to establishing total transfer capability limits under normal system conditions,

transmission providers and control areas shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3. **Joint agreement on limits.** All total transfer capability limits will be jointly agreed to by neighboring transmission providers or control areas.

B. Emergency Operations

1. **Emergency plans.** A set of plans shall be developed, maintained, and implemented as required by each operating entity or coordinated group of operating entities to cope with operating emergencies. These plans shall be coordinated with the Security Coordinators and other entities or coordinated groups of entities as appropriate. The plans shall be reviewed at least annually to ensure that they are up to date and a copy of the plans shall be provided to the Security Coordinators and shared with other entities as appropriate.

2. **Loads requiring backup power.** A reliable, adequate and automatic backup power supply shall be provided for the control center and other critical locations to ensure continuous operation of control equipment, communication channels, metering and recording equipment and other critical equipment during loss of normal power supply. Such backup power supply shall be adequate to carry equipment through a prolonged power interruption.

C. Automatic Load Shedding and System Sectionalizing

All control areas, coordinated groups of entities, and other entities serving load, shall jointly determine potential system separation points and resulting system islands and establish a program of automatic high-speed load shedding designed to arrest frequency decay. Such a program is essential in minimizing the risk of total system collapse in the event of separation, protecting generating equipment and transmission facilities against damage, providing for equitable load shedding among entities serving load and improving overall system reliability. Such islanding and load shedding should be controlled so as to leave the islands in such condition as to permit rapid load restoration and reestablishment of interconnections.

1. **WSCC regional coordination.** As new transmission facilities are constructed and study results and/or actual operating experience indicate differing islanding patterns, individual area load shedding programs shall be altered or integrated into other area programs to maintain an overall coordination of load shedding programs within the WSCC.

   A coordinated load shedding program shall be implemented to shed the necessary amount of load in each island area to arrest frequency decay, minimize loss of load and permit timely system restoration. Such island areas shall devise load shedding plans in accordance with the criteria outlined in the subsections that follow. As part of its participation in a coordinated load shedding program with neighboring entities, each entity serving load shall be equipped to automatically shed load at separate frequency levels over an appropriate frequency range. The load shedding shall be matched to the island area needs and coordinated within the island area.

2. **Underfrequency relays.** All automatic underfrequency load shedding comprising a coordinated load shedding program shall be accomplished by use of solid-state underfrequency relays. Electro-mechanical relays shall not be used as part of any coordinated load shedding program. In each island area, all relay settings shall be coordinated and based on the characteristics of that island area. It is essential that the underfrequency load shedding relay settings are coordinated with underfrequency protection of generating units and any other manual or automatic actions which can be expected to occur under conditions of frequency decline.

3. **Technical studies.** The coordinated automatic load shedding program shall be based on studies of system dynamic performance, under conditions which would cause the greatest potential imbalance between load and generation, and shall use the latest state-of-the-art computer analytical techniques. The studies shall be able to predict voltage and power transients at a widespread number of locations, as well as the rate of frequency decline, and shall reflect the operation of underfrequency sensing devices.

4. **Load shedding steps.** Automatic high-speed load shedding shall comply with the *WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* so as to minimize the risk of further separation, loss of generation, excessive load shedding accompanied by excessive overfrequency conditions, and system shutdown.

5. **Generators isolated to local load.** Where practical, generators shall be isolated with local load to minimize loss of generation and enable timely system restoration in situations where the load shedding program has failed to arrest frequency decline.

6. **Separation.** The opening of intra-area and inter-area transmission interconnections by underfrequency relaying shall only be initiated after the coordinated load shedding program has failed to arrest frequency decline and intolerable system conditions exist.

7. **Voltage reduction.** If voltage reduction is utilized for manual load relief, such reduction shall not be made to the high voltage transmission system.

8. **Protection from high frequency.** In cases where area isolation with a large surplus of generation in relation to load requirements can be anticipated, automatic generator tripping or other remedial measures shall be used to prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage.

D. System Restoration

1. **Restoration plan.** Each transmission provider and control area shall have an up-to-date restoration plan and provide personnel training and telecommunication facilities needed to implement the restoration plan following a system emergency. Entities and coordinated groups of entities shall coordinate their restoration plans with other affected entities or coordinated groups of entities. All restoration plans shall be reviewed a minimum of every three years.

2. **Synchronizing.** To the extent possible, synchronizing locations shall be determined ahead of time and dispatchers shall be provided appropriate procedures for synchronizing. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect resynchronization.

E. Control Center Backup

Each control area shall have a plan to provide continued operation in the event its control center becomes inoperable. For interconnected operations, the goal of this plan is to avoid placing a prolonged burden on neighboring control areas during a control center outage. Since most control centers differ in their internal functions and responsibilities, each control area should decide which specific functions, other than the basic functions shown below, will be necessary to continue their operations from an alternate location. These criteria do not obligate control areas to provide complete and redundant backup control facilities, but to provide essential backup capability. Each control area may, as an option, make appropriate arrangements with another control area to provide the minimum backup control functions in the event its primary control functions are interrupted. As part of its plan the control area is expected to comply with the following requirements (through automatic or manual means) as a minimum:

1. **Notification.** Provide prompt notification, which should include any necessary pertinent information, to other control areas in the event that primary control center functions are interrupted.

2. **Communications.** Maintain basic voice communication capabilities with other control areas.

3. **Schedules.** Maintain the status of all interarea schedules such that there is an hourly accounting of all schedules.

4. **Critical interconnections.** Know the status of and be able to control all critical interconnection facilities.

5. **Tie line control.** Provide basic tie line control capability to avoid burdening neighboring control areas with excessive inadvertent interchange.

6. **Periodic tests.** Conduct periodic tests of backup and control functions to ensure they are in working order.

7. **Procedures and training.** Provide adequate written procedures and training to ensure that operating personnel are able to implement all backup control functions when required.

Section 7 - Telecommunications

For a high degree of service reliability under normal and emergency operation, it is essential that all entities have adequate and reliable telecommunication facilities.

A. Facilities

1. **Between control centers.** At least one main telecommunication channel with an alternate backup channel shall be provided between control centers of adjacent interconnected control areas, between control centers and key stations within a control area, and between other control areas as required.
2. **Alternate facilities.** Alternate facilities shall be provided to protect against interruption of essential telemetering, control and relaying telecommunications.
3. **Standby power supply.** Telecommunication facilities shall be provided with an automatic standby emergency power supply adequate to supply requirements for a prolonged interruption.

B. WSCC Communication System

Control area control centers shall be connected to the WSCC Communication System either directly or via pool communication facilities and the terminals shall be readily available to the dispatchers. Other transmission providers are encouraged to be connected to the WSCC Communication System.

C. Loss of Telecommunications

Each control area shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunication facilities.

Section 8 - Operating Personnel and Training

To maintain a high degree of interconnected power system reliability, it is necessary that the interconnected power system be operated by qualified and knowledgeable personnel.

A. Responsibility and Authority

1. **Written authority.** Each system operator shall be delegated sufficient authority in writing to take any action necessary to ensure that the system or control area for which the operator is responsible is operated in a stable and reliable manner.

B. Requirements

1. **Dispatchers/System Operators and plant operators.** Dispatchers/System Operators and plant operators shall be qualified, trained and thoroughly indoctrinated in the principles and procedures of interconnected power system operation.
2. **Other personnel.** Other personnel involved in system operations, including, but not limited to, schedulers, contract writers, marketers, and energy

accountants, shall be thoroughly familiar with the procedures and principles of interconnected power system operation which pertain to their job function.

C. Training

1. **Regular training.** Training shall be conducted regularly to keep all operating personnel involved in the operation of the interconnected power system abreast of changing conditions and equipment on their own system and on other interconnected systems. WSCC Members and other entities are encouraged to use the WSCC Training Program as a supplement to their internal training programs.

2. **Contingency analysis.** System operating personnel shall be kept informed through appropriate power flow and stability studies of the effect that failure or loss of various system components has upon the reliability of their control area and the interconnected systems.

D. Certification.

Statement of intent: Certification is intended to apply to those Dispatchers/System Operators in a position to make and/or carry out decisions, without review by higher authority, that impact interconnected system reliability. "Higher authority" means entities such as Control Areas, ISOs, and Security Coordinators.

Personnel who must be certified:

- Security Coordinators;
- Dispatchers/System Operators who:
  - are employed by a WSCC Operating Authority, and
  - have the primary responsibility, either directly or through communication with others, for the real-time operation of the Western Interconnection , and
  - are directly responsible for complying with WSCC Minimum Operating Reliability Criteria,

shall be WSCC-Certified. Dispatchers/System Operators on shift, including shift supervisors, and management personnel who direct the real-time actions of Dispatchers/System Operators shall be WSCC-Certified (i.e., only WSCC-Certified personnel may direct the real-time operation of the power system). In addition, WSCC Trainers shall be both NERC- and WSCC-Certified. Certification is not intended to apply to substation or power plant operators.

Exception. *Any organization required to have WSCC-Certified Dispatchers/System Operators shall have a period not to exceed three years from the time it employs a new Dispatcher/System Operator or a new trainee in the Dispatcher/System Operator position to ensure the new employee attains WSCC Certification. For at least the first of those three years, the uncertified Dispatcher/System Operator shall work only in a non-independent position with a WSCC-Certified Dispatcher/System Operator.*

Operating Authority Definition. Control Areas and Independent System Operators are considered Operating Authorities.

Period of Certification. The WSCC Dispatcher/System Operator Certification credential shall be valid for a period of five years from the date of passing the certification examination.

a) **Recertification.** To maintain a continuous WSCC Certification credential, WSCC-Certified Dispatcher/System Operators shall be recertified before their current certification expires.

b) **Lapsed Certification.** If a Dispatcher/System Operator's WSCC Certification credential expires, or if the Dispatcher/System Operator fails the recertification examination, the Dispatcher/System Operator shall not be considered a WSCC-Certified Dispatcher/System Operator.

Certification Examination. The certification examination shall measure the Dispatcher/System Operator's knowledge of the WSCC Minimum Operating Reliability Criteria, WSCC Policies and Procedures and the basic principles of operating the Western Interconnection.

Administration. The WSCC Dispatcher/System Operator Certification examination will be administered on a pre-scheduled periodic basis at sites in the western United States and Canada.

E. Information Sharing

1. **Information requirements.** Each operating entity's personnel shall respond to the information requirements of other operating entities, coordinated groups of operating entities, and the WSCC Operations Committee.

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