WECC Coordinated Off-Nominal Frequency
Load Shedding and Restoration Requirements

1 There should be a coordinated off-nominal frequency program throughout all of WECC. Local differences are permitted as long as it can be demonstrated that the WECC Coordinated Plan is not adversely affected. (Reference A)

2A WECC should adopt the 59.1 Hz Plan as a minimum standard. (Reference A)

Table 1
WECC Coordinated Underfrequency Load Shedding Plan

Load Shedding Block	% of Customer Load Dropped	Pickup (Hz)	Tripping Time*
1	5.3	59.1	14 cycles
2	5.9	58.9	14 cycles
3	6.5	58.7	14 cycles
4	6.7	58.5	14 cycles
5	6.7	58.3	14 cycles
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	60 sec
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	15 cycles

* Tripping time includes relay and circuit breaker times.

2B The system average total tripping (relay & breaker) time should be no more than 14 cycles at the indicated frequency set points. (Reference A)

2C Intermittent load shall not be used unless monitoring is in place to allow changes in real time to accommodate the availability of the intermittent load and ensure the load shedding requirements of the Coordinated Plan are met. (Reference A)

2D Additional load can be tripped at frequencies higher than 59.1 Hz provided it does not violate the MORC or adversely impact neighboring systems. Frequency overshoot must be adequately addressed. (Reference A)

2E It is not permissible to start shedding load at frequencies lower than 59.1 Hz or to trip less load than called for by the Coordinated Plan. (Reference A)

2F Additional frequency set points can be used provided the cumulative total load shedding amounts meet the requirements of the Coordinated Plan for each of the Plan's frequency set points. (Reference A)

2G Where programs differ from the WECC Coordinated Plan, member systems are responsible for conducting studies to verify compliance with the Plan. These studies will be reviewed by the Underfrequency Implementation Task Force. (Reference A)

3A All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WECC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration. (Reference A)

3B To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational. (Reference A)

4 Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one-second-time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented. (Reference A)

5A Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames (Reference B & C):

Under-frequency Limit	**Over-frequency Limit**	**WECC Minimum Time**
> 59.4 Hz	60 Hz to < 60.6 Hz	N/A (continuous operation)
≤ 59.4 Hz	≥60.6 Hz	3 minutes
≤ 58.4 Hz	≥61.6 Hz	30 seconds
≤ 57.8 Hz		7.5 seconds
≤ 57.3 Hz		45 cycles
≤ 57 Hz	>61.7 Hz	Instantaneous trip

5B Systems that have generators that do not meet the requirements in Item 5A must automatically trip load (in addition to that required in Item 2A) to match the anticipated generation loss and at comparable frequency levels. (Reference A)

5C All systems that own/operate generating facilities shall provide data to WECC regarding the off-nominal frequency protection settings of their units. Any changes in settings shall also be reported. (Reference A)

6A Only solid state and/or microprocessor underfrequency relays shall be used as part of the Coordinated Plan. Only load tripped by solid state and/or microprocessor underfrequency relays will be considered when determining compliance with the Coordinated Plan. (Reference A)

6B Only solid state and/or microprocessor frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz. (Reference A)

6C All frequency relays shall use the definite time characteristic and should not be disabled for voltages 80% of nominal or higher but can be disabled for voltages below 80% of nominal (at the discretion of the setting entity). (Reference A)

6D Electro-mechanical frequency relays can be used only for settings outside the 57.9-61.0 Hz range. (Reference A)

7 To protect against overvoltages following an underfrequency load shedding event, systems shall implement automatic measures to maintain voltages within acceptable limits. (Reference A)

8 Direct load tripping is allowed if it complements the Coordinated Plan. (Reference A)

9 Each of the 4 Security Coordinators shall develop comprehensive and detailed guides for the restoration of load following a load shedding event. (Reference A)

Reference A: WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, dated November 25, 1997.

Reference B: Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, dated January 21, 2003.

Reference C: Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan – Phase 2, dated March 31, 2005.

Reference D: Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan – Phase 3, dated April 1, 2005.

Approved by Planning Coordination Committee October 30, 2003
Approved by Board of Directors December 5, 2003

Reference A

WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Final Report

November 25, 1997

Prepared by

Underfrequency Issues Work Group *
WSCC Technical Studies Subcommittee

***   Steven Mavis (CAISO, Chairman)**
Joaquin Aguilar (EPE)
Duane Braunagel (PRPA)
Barry Francis (BEPC)
Chris Oakley (TAUC)

Table Of Contents

I. Executive Summary

In the aftermath of the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Systems Coordinating Council (WSCC) electrical transmission system, a group of WSCC members performed comprehensive assessments culminating in two reports: the "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996," and "WSCC Disturbance Report For the Power System Outage that Occurred on the Western Interconnection on August 10, 1996" (Disturbance Reports). In the Disturbance Reports' recommendations, several reliability issues were identified for further investigation. One of the reliability issues involves the efficacy of existing off-nominal frequency related policies and procedures (e.g. underfrequency load shedding (UFLS) programs) to arrest potential system collapses due to large frequency deviations and minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operation.

Recommendations in the Disturbance Reports request WSCC to undertake a complete review of its members' underfrequency load shedding programs. Specific areas to be evaluated include coordination with generator off-nominal frequency protection requirements, coordination of automatic and manual load restoration, and coordination between and within regions.

On November 8, 1996, the WSCC Technical Studies Subcommittee (TSS) formed the ad hoc Underfrequency Issues Work Group (UIWG) to respond to the recommendations in the Disturbance Reports related to underfrequency issues. The general assignment given to the UIWG is summarized as follows:

- Determine if a uniform off-nominal frequency program can be specified for all of WSCC
- If yes, recommend a uniform off-nominal frequency program
- Recommend a policy regarding the automatic restoration of load
- Recommend a policy regarding the intentional tripping of tie lines and generators due to underfrequency

The UIWG has completed a comprehensive assessment of underfrequency issues to complete its general assignment and more. General principles including a specific UFLS plan have been developed as part of the overall assessment and formally documented herein. This assessment incorporates comments received from the Planning Coordination Committee, the Operations Committee, the Technical Studies Subcommittee, the Compliance Monitoring and Operating Practices Subcommittee, and the Technical Operation Subcommittee. These same Committees and Subcommittees approved the Final Draft of the assessment dated June 17, 1997, at their respective meetings during the summer of 1997. Though the Operations Committee approved the Final Draft at their June 1997 meeting, their approval was conditional, requiring Operations Committee members to review the Final Draft's Coordinated Plan and determine if the Plan could be implemented to their satisfaction.

To facilitate the review and implementation process, the Operations Committee formed the Underfrequency Program Implementation Task Force. After a review and comment period lasting roughly 30 days, the Underfrequency Program Implementation Task Force met in early

September 1997 to amend the recommendations of the Coordinated Plan. The Operations Committee and the Planning Coordination Committee approved the amended Coordinated Plan at the September 1997 meeting and the October 1997 meeting, respectively. This Final Report of the "WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan" incorporates the amended Coordinated Plan as approved by the Operations Committee and the Planning Coordination Committee. On December 4, 1997, the WSCC Board of Trustees approved the Coordinated Plan.

It is recognized that specific details of compliance with implementing the Coordinated Plan need to be developed over time within the appropriate WSCC groups.

The UIWG would like to acknowledge the contributions of many groups and individuals, on both the planning and operating sides of the WSCC, for the successful completion of this assessment, culminating in the Coordinated Plan. As a quick reference for the reader, the Coordinated Plan is listed on the following 3 pages.

Coordinated Plan

1 There should be a coordinated off-nominal frequency program throughout all of WSCC. Local differences are permitted as long as it can be demonstrated that the WSCC Coordinated Plan is not adversely effected.

2A WSCC should adopt the 59.1 Hz Plan as a minimum standard.

Load Shedding Block	% of customer load dropped	pickup (Hz)	tripping time
1	5.3	59.1	-
2	5.9	58.9	-
3	6.5	58.7	-
4	6.7	58.5	-
5	6.7	58.3	-
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

2B The system average total tripping (relay & breaker) time should be no more than 14 cycles at the indicated frequency set points.

2C Intermittent load shall not be used unless monitoring is in place to allow changes in real time to accommodate the availability of the intermittent load and ensure the load shedding requirements of the Coordinated Plan are met.

2D Additional load can be tripped at frequencies higher than 59.1 Hz provided it does not violate the MORC or adversely impact neighboring systems. Frequency overshoot must be adequately addressed.

2E It is not permissible to start shedding load at frequencies lower than 59.1 Hz or to trip less load than called for by the Coordinated Plan.

2F Additional frequency set points can be used provided the cumulative total load shedding amounts meet the requirements of the Coordinated Plan for each of the Plan's frequency set points.

2G Where programs differ from the WSCC Coordinated Plan, member systems are responsible for conducting studies to verify compliance with the Plan. These studies will be reviewed by the Underfrequency Implementation Task Force.

3A All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WSCC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration.

3B To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational.

4 Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one-second-time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

5A Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames:

Underfrequency Limit	Overfrequency Limit	Minimum Time
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operating range)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

5B Systems that have generators that do not meet the requirements in Item 5A must automatically trip load (in addition to that required in Item 2A) to match the anticipated generation loss and at comparable frequency levels.

5C All systems that own/operate generating facilities shall provide data to WSCC regarding the off-nominal frequency protection settings of their units. Any changes in settings shall also be reported.

6A Only solid state and/or microprocessor underfrequency relays shall be used as part of the Coordinated Plan. Only load tripped by solid state and/or microprocessor underfrequency relays will be considered when determining compliance with the Coordinated Plan.

6B Only solid state and/or microprocessor frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz.

6C All frequency relays shall use the definite time characteristic and should not be disabled for voltages 80% of nominal or higher but can be disabled for voltages below 80% of nominal (at the discretion of the setting entity).

6D Electro-mechanical frequency relays can be used only for settings outside the 57.9-61.0 Hz range.

7 To protect against overvoltages following an underfrequency load shedding event, systems shall implement automatic measures to maintain voltages within acceptable limits.

8 Direct load tripping is allowed if it complements the Coordinated Plan (see Item 2G).

9 Each of the 4 Security Coordinators shall develop comprehensive and detailed guides for the restoration of load following a load shedding event.

II. Background

In the aftermath of the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Systems Coordinating Council (WSCC) electrical transmission system, a group of WSCC members performed comprehensive assessments culminating in two reports: the "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996," and "WSCC Disturbance Report For the Power System Outage that Occurred on the Western Interconnection on August 10, 1996" (Disturbance Reports). In the Disturbance Reports' recommendations, several reliability issues were identified for further investigation. One of the reliability issues involves the efficacy of existing off-nominal frequency related policies and procedures (e.g. underfrequency load shedding (UFLS) programs) to arrest potential system collapses due to large frequencies deviations and minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operation.

Recommendations in the July and August disturbance reports require WSCC to undertake a complete review of its members' underfrequency load shedding programs. Specific areas to be evaluated include coordination with generator off-nominal frequency protection requirements, coordination of automatic and manual load restoration, and coordination between and within regions.

III. General Assignment

The WSCC Technical Studies Subcommittee (TSS) formed the ad hoc Underfrequency Issues Work Group (UIWG) on November 8, 1996 to address the underfrequency issues identified in the Disturbance Reports. The UIWG prepared a Underfrequency Issues Work Plan (Attachment 1) which defined the assignment in more specific detail, identified the deliverables, and outlined the general methodology for accomplishing the task. The general assignment is summarized as follows:

- Determine if a uniform off-nominal frequency program can be specified for all of WSCC
- If yes, recommend a uniform off-nominal frequency program
- Recommend a policy regarding the automatic restoration of load
- Recommend a policy regarding the intentional tripping of tie lines and generators due to underfrequency

IV. NERC and WSCC General Policy and Guidelines

Both NERC and WSCC present guidelines for proper design of an off-nominal frequency program.

Policy 4, Subsection D, Criteria of the NERC Operating Guides states the following:

"Systems and control areas shall coordinate the application, operation, and maintenance of protective relays on the bulk electric system, including the coordination of underfrequency load shedding relays. They shall develop criteria which will enhance their system reliability with the minimum adverse effect on the Interconnection. (C.II.D.)"

NERC Policy 5 in the Operating Manual titled Emergency Operations (Attachment 2), addresses the issues of generator protection, load restoration, frequency restoration, and regional coordination. The following statement from Policy 5 summarizes the overall objectives of the off-nominal frequency program:

"Each system, control area, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of that interconnection. The program shall be coordinated throughout the interconnection to prevent unbalanced load shedding which may cause high transmission loading and extreme voltage deviations."

Section 6.C of the WSCC Minimum Operating Reliability Criteria (MORC), dated March 1997 (Attachment 3), further clarifies the objectives and requirements of an off-nominal frequency program:

- Minimize the risk of total system collapse in the event of separation
- Protect generating equipment and transmission facilities against damage
- Provide for equitable load shedding among entities serving load
- Improve overall system reliability
- Leave the system in a condition to permit rapid load restoration and re-establishment of interconnections
- Should be matched to meet island area needs and coordinated within the island area
- Should coordinate with underfrequency protection of generating units
- Should coordinate with any manual or automatic action that can be expected to occur under conditions of frequency decline
- Should be based on studies of system dynamic performance, using latest state-of-the-art computer analytical techniques
- Should minimize the risk of further separation, loss of generation, or excessive load shedding accompanied by excessive overfrequency conditions
- Should incorporate automatic generator tripping or other remedial measures to prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage

Section 5.D of MORC (Attachment 3) specifies that restoration should begin by stabilizing the island and returning the system frequency to normal, synchronizing the islanded area with adjacent areas, and restoring customer loads as conditions permit. Start-up power should be provided to generating stations before customer load is restored.

V. Overall Study Objectives:

1. Be in total compliance with all WSCC and NERC policies or requirements.
2. Following an event that results in off-nominal frequencies, leave the system in such condition as to permit rapid load restoration, re-establishment of interconnections, and otherwise allow the dispatchers reasonable time to make "fine tuning adjustments" to restore the system to normal operation.
3. Develop a program that gives acceptable performance for a wide range of initiating disturbances.
4. Develop a program that is universal and does not have to be changed seasonally because of different load characteristics or patterns.
5. Have sound technical basis for recommendations , specifically demonstrating that the recommended uniform off-nominal frequency program:
    a. arrests frequency declines as good as or better and with less shedding of overall load compared to the status quo or other programs, and
    b. restores the system to nominal frequency and zeroed ACE in an expeditious manner, without violating equipment capabilities, and free of impediments.
6. Develop a coordinated off-nominal frequency program that factors in requirements of generators.

The WSCC system will be treated as a "one world" interconnection. This assumption is made to ensure that the primary emphasis of the analysis will be to improve the overall WSCC system performance.

VI. WSCC Uniform Program Policy

Not having a uniform or coordinated off-nominal frequency program throughout WSCC has exacerbated the consequences of actual disturbances. For example, regional differences in the UFLS program caused additional islands to form during the July 2 disturbance. The Rocky Mountain area (CO/WY/UT) automatically begins to trip load at a higher setting of 59.3 Hz than the Desert Southwest area (CA/AZ/NM/NV) setting of 59.1 Hz. In the July 2 disturbance, the Rocky Mountain area initially separated with the Desert Southwest area. The generation and load imbalance resulting from the load shed in the Rocky Mountain area at 59.3 Hz caused a surge of power to the south across the NE/SE transmission boundary, overloading that interface and causing it to open in a cascading fashion. The WSCC compiled a list of UFLS programs currently in place (Attachment 4), from which one can compare the differences between WSCC areas and member systems programs.

It is recognized that during a disturbance, there may be some slight variations in frequency at any given instant in time between different areas of the interconnection. However, as long as the interconnection remains intact the frequency will essentially be the same throughout the interconnection. The disturbance within the interconnection could be caused anywhere in the interconnection. In general, at the inception of the disturbance there is insufficient time to determine who is "causing the problem" and assign a load shedding responsibility to that party.

No technical reasons could be identified or demonstrated that would preclude the adoption of a uniform off-nominal frequency program throughout the WSCC. A uniform program approach could avoid the adverse consequences caused by the uncoordinated operation of individual programs. It also reinforces the concept of mutual support and shared benefits of the Western Interconnection by recognizing that all entities that derive benefits from the positive aspects of being connected to the grid must also contribute their fair share in mitigating the negative aspects.

Though a uniform program appears technically feasible and desirable, it is recognized that such a program needs to have boundaries and be flexible. For example, some systems may have special procedures in place to avoid a blackout scenario if the frequency drops to critically low levels. To allow for tailored procedures at these low frequencies, the uniform program should be bounded by a minimum frequency. Also, there may be valid local reasons to shed load in excess of that required by regional requirements. In the Rocky Mountain area, southeast Colorado (including the Denver metro area) imports a considerable amount of power from remote areas. This geographical area also islanded during a spring ice storm. Hence, the decision was made by the affected systems to increase the amount of load shedding in this localized area. Surrounding areas had a decreased load shedding requirement. Another potential problem with a uniform program is that if the disturbance originates within a heavily importing area, then the flows will be increased with the potential of overloading the transmission ties. This should be evaluated on an individual basis. If a problem is suspected, the importing areas should increase the amount of load shed with a corresponding decrease in the supplying area.

It was recognized that a coordinated plan, which combines the best of uniform standards and the best of individual procedures, should be adopted by the WSCC. Overall, the coordinated off-nominal frequency program met the larger geographical area requirements while providing for local area needs. The flexibility to meet local requirements needs to be retained, while still providing for the overall regional requirements.

Recommendation 1: There should be a coordinated off-nominal frequency program throughout all of WSCC. Local differences are permitted as long as it can be demonstrated that the WSCC Coordinated Plan is not adversely effected.

VII. WSCC Uniform UFLS Plan

Assumptions regarding specific design parameters needed to be identified and used to provide a quantifiable assessment of a uniform UFLS plan. It is recognized that actual parameters may deviate somewhat from the assumptions listed below without compromising the program.

Assumption 1: The uniform UFLS plan should coordinate with the 5% loss of life of turbine blades recommendations as determined by generator manufacturers. Turbine blade loss of life is the most limiting of the off-nominal frequency restrictions imposed by the generating units.

A 0% loss of life criteria implies that the generators are not exposed to any off-normal frequency operation outside of the continuous band. Some generators within WSCC have robust operating limits that permit operation within a relatively large bandwidth. Other regions like the Rocky Mountain area have determined that an off-nominal frequency program could be developed using the relatively conservative 5% loss of life criteria. Designing an off-nominal frequency program to meet the 5% loss of life criteria is an aggressive goal, but nevertheless a realistic goal. Owners/operators of generating units are more likely to accept the potential for loss of life to their units if this risk is minimized to the greatest extent possible.

Determining the loss of life for frequency excursions is not an exact science. Nevertheless, the manufacturers have developed recommendations. These requirements are described in ANSI/IEEE Standard C37.106-1987, Guide for Abnormal Frequency Protection for Power Generating Plants (Attachment 5). A composite requirement was made using the most restrictive limitations imposed by any manufacturer. This is shown graphically in Figure 1 and in tabular form below.

Underfrequency Limit	Overfrequency Limit	Maximum Time
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operating range)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

One advantage of trying to meet the 5% loss of life criteria is that it allows all generation owners to protect their units per manufacturer recommendations. This is an additional reason why generation owners/operators should support this off-nominal frequency program.

Assumption 2: Sufficient load should be dropped in uniform UFLS plan to leave the system frequency within the continuous operating range of the generating units.

The generating units can operate continuously between 59.5 Hz and 60.5 Hz. It would be desirable to have the frequency following a disturbance that results in underfrequency load shedding to be restored within this range to minimize the potential for loss of life. This will allow the dispatcher time to analyze the situation and make appropriate adjustments to restore ties and the frequency to 60 Hz. If the frequency were left in the “time to damage” range of the generating units, immediate response is required of the dispatcher to be totally effective within minutes otherwise some generators may automatically trip to prevent further damage. This is both impractical and unnecessary.

Assumption 3: The uniform UFLS plan should provide coverage during a substantial loss of generation or resources (e.g. 25-33%).

A UFLS plan can be designed for a 50% range of generation overload. For example, a 33% loss of generation represents a 50% overload on remaining generation. A 50% loss of generation represents a 100% overload on remaining generation. A good off-nominal underfrequency program can be designed for a 0%-50% generation overload, a 25%-75% overload, or a 50%-100% overload. A program designed for a 50%-100% overload will not work at all for a contingency that involves only a 0%-50% overload.

The loss of 33% of total generation is, by any standard, a severe contingency. As a practical matter, a well behaved UFLS program cannot be designed for loss of generation beyond 33% unless load is massively over shed at high frequencies to prevent the dynamic frequency from falling below the point at which units trip instantaneously (56.5 Hz). This massive over shedding of load must then be accompanied by massive automatic and high speed load restoration to prevent the units from tripping due to overfrequency. The program designed for loss of generation beyond 33% will not work at all for loss of generation less than 33%. In view of these problems, the uniform off-nominal program should be designed up to a maximum generation and load imbalance of 33%.

Assumption 4: The minimum permissible dynamic frequency during a disturbance is 57.9 Hz. The maximum permissible dynamic frequency during a disturbance is 61.0 Hz.

Discussion: This minimum limit of 57.9 Hz was chosen because the allowable time of operation below 57.9 Hz to coordinate with the 5% loss of life criteria, is only 7.5 seconds. Intentional operation below 57.9 Hz was judged to be imprudent.

The maximum limit of 61 Hz was chosen because above this frequency some governors may go into an “emergency over speed mode” and close the main steam control valves. This causes the boiler to go into an “upset condition” and the unit will trip in the short term if the frequency is not reduced or may trip in the longer term because of the unstable boiler condition. A maximum frequency limit of greater than 61 Hz could have been chosen and still coordinate with the emergency controls of the governor, but as a practical matter the 61 Hz limit is easily achieved.

Assumption 5: Current UFLS plans utilize 5-6 steps, but a new and uniform UFLS plan for WSCC need not be restricted to this number. The minimum separation between steps should be 0.1 Hz.

As a practical matter, it is just as easy to administer a 10 step UFLS plan as a 6 step program (per CMOPS, with the understanding that there will be an uniform UFLS plan throughout WSCC). If we can get better performance with a 10 step UFLS plan than a 6 step program, then it ought to be considered. Absent any technical considerations, the preference would be to have fewer steps rather than more.

The underfrequency relay manufacturers provide set points in increments of 0.01 Hz. However, practical considerations suggest that the minimum separation between steps should be 0.1 Hz. Equipment instruction manuals for two relay manufacturers are provided (Attachment 6).

Assumption 6: Underfrequency relays have a maximum operating time of 6 cycles.

Relay manufacturers state that the minimum operating time of their equipment is 3.4 cycles. This is a hardware consideration. There are no advantages to having operating times longer than 6 cycles that incorporate some additional intentional detection time, and longer detection times or intentional time delay will destroy the integrity of the off-nominal program. It is the intent that additional time delay not be introduced beyond that inherent in the equipment itself.

Assumption 7: As a system average, a 6 cycle operating time of breakers is used to trip load.

Many systems will use distribution breakers to trip load. These distribution breakers are typically slower than transmission breakers. Although some systems will use transmission breakers to trip load, a system wide and conservative figure of 6 cycles will be used. This is not to imply that only breakers that operate in 6 cycles or less can be used in the UFLS plan. However, Assumptions 6 and 7 taken together imply that load will tripped 12 cycles after the frequency reaches the threshold level and that this 12 cycle operating time to trip the load is a system average. Moreover, there should be no intentional time delay introduced.

Assumption 8: If there is any discretion allowed, the preferred option is to have the post-disturbance frequency settle out above 60 Hz, as opposed to below 60 Hz.

If the frequency settles out above 60 Hz (but less than 60.5 Hz), then in short order the governors will automatically act to restore the system to 60 Hz. This will facilitate the restoration of ties (in the case of islanding) and in any event it is the preferred operating mode of the generators (to prevent spurious trips within the generating plant). If the frequency levels out below 60 Hz (but above 59.5 Hz), then governors will act to raise generation, however longer time delays are potentially possible because additional fuel must be added to boilers before the increased generation can be supported. There is also the possibility that increased generation may not be available, and load must be manually shed to achieve 60 Hz. A post-disturbance frequency of 60 Hz or slightly above is judged to maximize the dispatcher's ability to initiate system restoration activities.

Study Methodology:

An underfrequency disturbance event will typically have all load shed within 0.3 and 10 seconds after the inception of the disturbance. Governors will not operate to adjust MW output levels by any appreciable amount in this time frame, which means the frequency will change in accordance with the system inertial response characteristic. Looking at frequency alone, a simple model can be constructed using one equivalent generator supplying total system load (generator auxiliary power, losses, and customer load). The frequency response characteristics of load and generation are properly accounted for in this simple model. The simple model cannot account for transient variations in load resulting from transient variations in voltage. Whatever the voltage effect is, only the net generation and load imbalance affects the frequency.

A full network model using the transient stability program can include the effects of voltage on the load as well as losses during the dynamic time frame. The detailed program calculates the voltage profile resulting from a specific disturbance scenario, and presuming that the relationship between transient load and transient voltage is known, the net effect on the transient frequency can be determined. The detailed program can also show transient flows on the transmission system, and simulate islanding patterns.

The basic methodology is to use the simple equivalent model to develop a proposed uniform UFLS plan. The equivalent model is explained in detail in the GE publication title “Load Shedding, Load Restoration, and Generator Protection Using Solid-state and Electromechanical Relays” (Attachment 7). This method is explained further in the WSCC publication prepared by the Relay Work Group titled “Underfrequency Load Shedding Relay Application Guide” (Attachment 8).

This proposed UFLS plan is to be designed to accommodate a wide range of generator inertias and load/frequency characteristics. However, the program is to be optimized using the system average inertia and nominal load/frequency response characteristic.

The proposed UFLS plan resulting from the simplified analysis was “verified” using the full transient stability program. Base cases representing the December 14, 1994 and August 10, 1996 disturbances were used to confirm the adequacy of the proposed program.

The UFLS plan is able to meet Assumptions 1-8 identified above with generator inertia as low as 2.5 pu. and as high as 6.0 pu. The low inertia represents large steam units and the high inertia represents hydro units. The load sensitivity to frequency is the ratio between the percent load change to the percent frequency change. A system wide value of 1.5 is the recommended value in literature and is based on measurements. Because load decreases faster than frequency, the frequency settles out at some reduced value whenever there is a trip of generation. The off-nominal frequency program should meet the criteria identified above for load sensitivities as low as 1.0 and as high as 2.0.

The rationale for evaluating various values of equivalent generator inertia is that the mix of generation that trips during a disturbance is random, meaning that the mix of generation remaining after a disturbance is also random. This is especially true when the initiating disturbance can occur anywhere within WSCC. The rationale for evaluating various load sensitivities is that the characteristics of load can change radically between seasons and geographic areas. The intent is to have a static off-nominal frequency program that does not change seasonally and will give acceptable performance for a wide range of initiating disturbances.

The UFLS plan is to be designed to meet the criteria specified above for losses of generation of 1%, 2%, 3%, 4%, 5%, 10%, 15%, 20%, 25%, and 30%.

Study Results:

The following two plans adhered to Assumptions 1-8 and gave acceptable performance for all combinations of generator inertia, load-frequency relationships, and generator-load imbalances. Plan 59.3 has the first load shedding block at 59.3 Hz, and Plan 59.1 has the first load shedding block at 59.1 Hz. Both options were prepared in recognition that the northern portion of WSCC currently begins their UFLS plan at 59.3 Hz and the southern portion for the most part begins their UFLS plan at 59.1 Hz. In the simplified model, total load is comprised of customer load, losses, and generating station auxiliary power. A UFLS plan should not trip generating station auxiliary power and cannot directly affect losses (however system losses may go up or down following the disturbance). Therefore, there must be a relationship derived between total load and customer load. To derive this relationship, losses were assumed to 3% and generation auxiliary power to be 8% of gross generating station output. One unit of total load thereby becomes 1.12 units of customer load.

Plan 59.3

total load dropped (gross)	customer load dropped	pickup Hz	relay detection time-cycles	total tripping time-cycles
4.50%	5.06%	59.3	6	12
5.00%	5.62%	59.1	6	12
5.50%	6.18%	58.9	6	12
5.25%	5.90%	58.7	6	12
5.00%	5.62%	58.5	6	12
4.75%	5.33%	58.3	6	12
Additional automatic load shedding to correct underfrequency stalling				
2.00%	2.25%	59.3	-	15 sec
1.50%	1.69%	59.5	-	30 sec
1.78%	2.00%	59.5	-	1 min
Load automatically restored from 59.3 Hz block to correct frequency overshoot				
1.00%	1.12%	60.5	-	30 sec
1.50%	1.69%	60.7	-	5 sec
2.00%	2.25%	60.9	-	12

Plan 59.1

total load dropped (gross)	customer load dropped	pickup Hz	relay detection time-cycles	total tripping time-cycles
4.75%	5.33%	59.1	6	12
5.25%	5.90%	58.9	6	12
5.75%	6.46%	58.7	6	12
6.00%	6.74%	58.5	6	12
6.00%	6.74%	58.3	6	12
Additional automatic load shedding to correct underfrequency stalling				
2.00%	2.25%	59.3	-	15 sec
1.50%	1.69%	59.5	-	30 sec
1.78%	2.00%	59.5	-	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot				
1.00%	1.12%	60.5	-	30 sec
1.50%	1.69%	60.7	-	5 sec
2.00%	2.25%	60.9	-	12

A summary of the performance for the various combinations studied (using the equivalent inertia model) for both Plan 59.3 and 59.1 is provided in the tables section (XVI. Tables). Note that the generator inertia has no impact on the ultimate steady state frequency but does impact the rate at which these frequencies will vary. The most sensitive variable is the load/frequency response characteristic.

The load dropped at 59.5 Hz with a 30-second time delay and at 59.3 Hz with a 15-second time delay is an integral part of the program but also solves the problem experienced in the Rocky Mountain area during the July 2 disturbance. In this incident the first two steps of load shedding occurred, but over time additional generation tripped and the frequency gradually decayed to slightly below 59.4 Hz. This frequency is in the "time to damage" characteristic of some major generating units, and they were beginning to time out with a three minute delay. Fortunately, the frequency rose above the frequency threshold before the relays timed out, but this was mere coincidence and not a result of a deliberate action taken by the dispatchers to "beat the relay."

In the simplified model, both plans yield acceptable and equivalent performance. Both plans have the same delayed trip at 59.5 Hz and 59.3 Hz, and the same automatic restoration at 60.5 Hz, 60.7 Hz, and 60.9 Hz. The plan beginning at 59.3 Hz utilizes six steps in the high speed portion tripping a total of 33.71% of customer load. The plan beginning at 59.1 Hz utilizes five steps in the high speed portion tripping a total of 31.17% of customer load. The difference in the amount of customer load tripped is indicative of the limited amount of time spent to "optimize" each plan, and if this difference is significant then additional effort should be made in this area.

Some customers self-protect themselves and trip their load automatically at frequencies higher than either 59.3 Hz or 59.1 Hz. Some utilities trip their interruptible load at frequencies higher than either 59.3 Hz or 59.1 Hz. The requirement is that by the first step (either 59.1 Hz or 59.3 Hz) the target amount of load should be dropped. In any event, the required amount of load available to be restored must be available from the highest block, e.g. the 59.3 Hz block in Plan 59.3 or the 59.1 Hz block in Plan 59.1.

Transient stability studies were conducted to confirm the performance of the UFLS plans now used by WSCC member systems, and Plans 59.3 and 59.1 discussed above. The plans were evaluated under two power flow cases which were considered to be representative of realistic boundary conditions in the WSCC. One power flow case was based on August 10, 1996 operating conditions which represent heavy north-to-south flows on the Pacific Interties (i.e. heavy imports into the Southern region). Two outages were simulated to compare the UFLS plans under different resource losses. The first outage (10% Outage) consisted of loss of the COI path followed by operation of the NE/SE separation scheme and other remedial measures (e.g. generator tripping in the NW); all of which result in the controlled formation of the Northern and Southern Islands. With loss of the COI and TOT2 paths, the Southern island suffered a resource deficiency of about 5,700 MW, or 10% (i.e. [Gen + Import loss]/[Total Gen + Import]). The second outage (27% Outage) is identical to the first plus an additional 9,000 MW loss of generation resulting in a total loss of resources of about 14,800 MW, or 27%.

The other power flow case was based on December 14, 1994 operating conditions which represent heavy south-to-north flows on the Pacific Interties (i.e. heavy imports into the Northern region). The outage was similar but not identical to the December 14, 1994 disturbance which resulted in the creation of Northern and Southern Islands. Rather than sequence the tie-line breaker operations and generator trips, everything was tripped at t = 1.0

second. This simultaneous action represents a more severe condition than the sequential loss of elements which occurred on December 14. This outage (29% Outage) represents a total loss of resources of about 9,000 MW, or 29%.

Based on the overall study results, both Plan 59.3 and Plan 59.1 provide satisfactory performance in terms of frequency dip and the rate of frequency restoration compared to the UFLS plans now in service. Plan 59.3 does appear to provide marginally better performance than Plan 59.1 and the UFLS plans now used in service. For example, Plan 59.3 results in lower frequency dips and faster frequency restoration, though at higher amounts of load shedding as shown in the stability results tables section (XVI. Tables). From a technical point of view, both Plan 59.3 and Plan 59.1 meet the study performance objectives of arresting the frequency and restoring the frequency within 59.5 and 60.5 Hz. Also, there does not appear to be a difference from an economic perspective, since either Plan 59.3 or Plan 59.1 would require all participating WSCC members to revise block sizes and reset relays. A parallel WSCC initiative is currently assessing the benefits of direct load tripping (DLT) in the southern island formed in response to an outage of the California-Oregon AC Interconnection (COI). A key result from the DLT effort is that the frequency excursion bottoms out at around 59.1 Hz absent the UFLS program. Clearly, if the UFLS Plan 59.3 and the DLT program were implemented at the same time, the initial frequency setting of the UFLS program would cause an unnecessary tripping of load for COI outages. In the interest of making these two important programs compatible, Plan 59.1 should be adopted as the WSCC UFLS plan.

Recommendation 2A: WSCC should adopt the 59.1 Hz Plan as a minimum standard.

Load Shedding Block	% of customer load dropped	pickup (Hz)	tripping time
1	5.3	59.1	-
2	5.9	58.9	-
3	6.5	58.7	-
4	6.7	58.5	-
5	6.7	58.3	-
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

Though the studies assumed a combined 12 cycle relay and breaker operating time, some WSCC member systems currently have a minimum operating time of 14 cycles due to equipment specifications. A sensitivity study showed imperceptible difference between changes in relay and breaker operating times shedding as shown in the stability results tables section for Modified Option #2 (XVI. Tables). Therefore, a system average total tripping (relay & breaker) time of no more than 14 cycles is being recommended.

Recommendation 2B: The system average total tripping (relay & breaker) time should be no more than 14 cycles at the indicated frequency set points.

The objective of the coordinated UFLS program is to have a program that functions properly independent of season, day of the week, time of day, or load level. Hence, intermittent load should not be an integral part of the coordinated program. Intermittent load in the context of this discussion refers to load whose status may be highly variable or unpredictable. Some examples are pumping load that may depend on water conditions or operate only during restricted time periods, or pumped storage facilities. This type of load may be the easiest to interrupt or have the lowest service priority, but unless the UFLS program is modified continuously to reflect the operating status of this intermittent load the UFLS program will not work properly. From a different perspective, not making this intermittent load an integral part of the UFLS program gives the dispatcher additional tools to easily balance load and generation or permit rapid restoration of customer load following the disturbance. Relying on intermittent load to meet regional load shedding requirements undermines the integrity of the entire UFLS program.

Recommendation 2C: Intermittent load shall not be used unless monitoring is in place to allow changes in real time to accommodate the availability of the intermittent load and ensure the load shedding requirements of the Coordinated Plan are met.

The following four recommendations were formulated by the Underfrequency Program Implementation Task Force to provide additional guidance in implementing the UFLS program as stated in Recommendation 2A.

Recommendation 2D: Additional load can be tripped at frequencies higher than 59.1 Hz provided it does not violate the MORC or adversely impact neighboring systems. Frequency overshoot must be adequately addressed.

Recommendation 2E: It is not permissible to start shedding load at frequencies lower than 59.1 Hz or to trip less load than called for by the Coordinated Plan.

Recommendation 2F: Additional frequency set points can be used provided the cumulative total load shedding amounts meet the requirements of the Coordinated Plan for each of the Plan's frequency set points.

Recommendation 2G: Where programs differ from the WSCC Coordinated Plan, member systems are responsible for conducting studies to verify compliance with the Plan. These studies will be reviewed by the Underfrequency Implementation Task Force.

VIII. Load Restoration

Policy 5 in the NERC Operating Manual contains the following statements:

"Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the system is restored."

"Automatic restoration of load may be used where feasible to minimize restoration time. Automatic restoration should be coordinated with neighboring systems, coordinated areas, and Regions. Automatic restoration should not aggravate system frequency excursions, overload tie lines, or burden any system in the Interconnection."

Article B2 of the NERC Performance Standard Training Document contained in the NERC Operating Manual contains the following statement:

"During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variations. However, an area is expected to activate operating reserve to recover ACE within ten minutes."

Section 5.D.4 of the WSCC Minimum Operating Reliability Criteria (MORC, March 1997) states the following:

"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 be accomplished through a comprehensive program established in thorough coordination with neighboring systems and designed to avoid the possibility of recreating underfrequency, overloading ties, or burdening neighboring systems. Relays installed to restore load automatically should be set with varying and relatively long time delays, except in those cases where automatic load restoration is designed to protect against frequency overshoot."

A 1% generation/load imbalance causes a steady state frequency deviation of 0.4 Hz as shown in the tables section (XVII. Tables). The off-nominal frequency program is designed to have a post-disturbance frequency within the range of 59.5-60.5 Hz because frequencies outside this range are within the "time to damage" characteristics of some generating units and are protected by time delay relays. MORC requires all control areas to continually maintain minimum spinning and operating reserves, available in ten minutes, to cover their largest resource loss or 5% of their loads served by hydro generation and 7% of their load requirements met with steam generation. MORC is correct in requiring relatively long time delays before automatic restoration is attempted. The Task Force suggests that automatic load restoration occur no sooner than thirty minutes after 60 Hz ($\mp$ 0.05 Hz) is restored, and no more than 2% every five minutes. Historically, islands are able to reestablish tie lines within this time period and additional generation is available. At no time should automatic restoration of load interfere with the efforts to reestablish interconnections and otherwise restore the system.

The minimum time delay of 30 minutes after the frequency has been restored to and stabilized at 60 Hz is expected to be sufficient enough to reestablish key interties prior to bringing hydro systems back on line, and thus allowing load to be automatically restored in a timely fashion. This is important from a system perspective; MORC suggests that the fastest way to restore the overall system is to reestablish the interconnections before load restoration begins. The local hydro areas must interface with the neighboring thermal areas. In addition, the relays that restore load automatically monitor only the frequency, not the status of system conditions. Hence, any automatic load restoration plan should be implemented using conservative assumptions as opposed to best case or even normal assumptions.

Recommendation 3A: All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WSCC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration.

Recommendation 3B: To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational.

IX. Tie Line Tripping

Section 6.C.6 of MORC states the following:

“ 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.”

Policy 5 in the NERC Operating Manual contains the following statements:

“When an operating emergency occurs, a prime consideration shall be to maintain parallel operation throughout the Interconnection. This will permit rendering maximum assistance to the system(s) in trouble.”

“Because the facilities of each system may be vital to the secure operation of the Interconnection, systems and control areas shall make every effort to remain connected to the Interconnection. However, if a system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system.”

The proposed UFLS program is designed to arrest the frequency decline at 57.9 Hz. If the frequency declines below 57.9 Hz, the “time to damage” of some generating units is within 7.5 seconds and “intolerable system conditions exist.” If a system decides to implement automatic tripping of tie lines due to underfrequency, then the set point should be no higher than 57.9 Hz, with a suggested time delay of one second to allow for a transient swing.

Tripping tie lines is not without risk. If the interconnection is supporting the individual system, then tripping the tie lines will almost certainly mean total collapse for that individual system. If the individual system is supporting the interconnection, then tripping the tie lines will put the interconnection at greater risk. Unless sophisticated relaying is implemented (perhaps looking at the direction of power flow), there is no way for an individual relay to discriminate between the two conditions. However, the ultimate decision rests with the individual system. From an overall system perspective, the preferred option is to not trip transmission lines due to underfrequency.

Recommendation 4: Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

X. Generators

Policy 4, Subsection D, Guide 1.6. of the NERC Operating Guides states the following:

"**Underfrequency relays.** Underfrequency load shedding relays should be coordinated with the generating plant off-frequency relays to assure preservation of system stability and integrity. (II.D.r.1.6.)"

Policy 5, Subsection D, Guide 2. of the NERC Operating Guides states the following:

"**Generator shutdown**. If abnormal levels of frequency or voltage resulting from an area disturbance make it unsafe to operate the generators or their support equipment in parallel with the system, their separation or shutdown should be accomplished in a manner to minimize the time required to re-parallel and restore the system to normal. (III.F.r.1.)

2.1 **Separating generators with local load.** If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliaries. (V.D.r.4.)"

Policy 5, Subsection D, Guide 5. of the NERC Operating Guides states the following:

"**Generator protection at high and low frequency**. Protection systems should be considered for automatically separating the generators from the system at predetermined high and low frequencies. (III.A.r.3.1.)"

One of the fundamental objectives is to implement an off-nominal frequency program that coordinates with the requirements of the generators. A corollary requirement is that the generators in turn coordinate with the off-nominal frequency program. The off-nominal frequency program was designed to coordinate with the most conservative 5% loss of life criteria imposed by any manufacturer. The generators, in turn, must not individually or unilaterally set their off normal frequency protection to be any tighter than that permitted by the

5% loss of life criteria specified by the manufacturers and assumed in the coordinated off-nominal frequency program.

Some units on the distribution system have much tighter frequency limitations to prevent them from being isolated on a radial feed with dramatic frequency swings. This is a legitimate requirement. From a system perspective, additional load must be tripped on a one-for-one basis to not degrade overall system integrity.

Recommendation 5A: Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames:

Underfrequency Limit	***Overfrequency Limit***	***Minimum Time***
60.0-59.5 Hz	***60.0-60.5 Hz***	***N/A (continuous operating range)***
59.4-58.5 Hz	***60.6-61.5 Hz***	***3 minutes***
58.4-57.9 Hz	***61.6-61.7 Hz***	***30 seconds***
57.8-57.4 Hz		***7.5 seconds***
57.3-56.9 Hz		***45 cycles***
56.8-56.5 Hz		***7.2 cycles***
less than 56.4 Hz	***greater than 61.7 Hz***	***instantaneous trip***

Recommendation 5B: Systems that have generators that do not meet the requirements in Recommendation 5A must automatically trip load (in addition to that required in Recommendation 2A) to match the anticipated generation loss and at comparable frequency levels.

Recommendation 5C: All systems that own/operate generating facilities shall provide data to WSCC regarding the off-nominal frequency protection settings of their units. Any changes in settings shall also be reported.

XI. Relays

Article 5.2 of MORC contains the following statement:

"All automatic underfrequency load shedding comprising a coordinated load shedding program shall be accomplished by the use of solid-state underfrequency relays. Electro-mechanical relays are not to be used as part of any coordinated load shedding program."

The above statement has been in MORC since 1974. This requirement is based on solid technical reasons and is not in dispute, hence the rationale will not be presented here. However, electro-mechanical relays are still in use and should be eliminated as part of the total review of the UFLS program.

The Relay Work Group would like to give visibility to their long standing recommendation that only the definite time characteristic of the underfrequency relay be used. An inverse time characteristic or rate of frequency characteristic is not to be used.

The Relay Work Group recommends that underfrequency relays be enabled for voltages as low as 80% of nominal, unless local conditions dictate otherwise. This recommendation was approved by the Technical Operations Subcommittee.

CMOPS recommends that only loads tripped by underfrequency relays should be considered when determining compliance with the UFLS plan.

TOS and CMOPS recommend that only solid state frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz .

TOS recommends that electromechanical frequency relays may be used for either load or generation only if their trip settings are outside the range of 57.9-61.0 Hz.

Recommendation 6A: Only solid state and/or microprocessor underfrequency relays shall be used as part of the Coordinated Plan. Only load tripped by solid state and/or microprocessor underfrequency relays will be considered when determining compliance with the Coordinated Plan.

Recommendation 6B: Only solid state and/or microprocessor frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz.

Recommendation 6C: All frequency relays shall use the definite time characteristic and should not be disabled for voltages 80% of nominal or higher but can be disabled for voltages below 80% of nominal (at the discretion of the setting entity).

Recommendation 6D: Electro-mechanical frequency relays can be used only for settings outside the 57.9-61.0 Hz range

XII. Overvoltage protection

When loads are shed suddenly during an underfrequency event, shunt capacitors remaining in service may cause serious overvoltages. Because of this condition, shunt capacitors on the transmission system should either have automatic overvoltage protection or be tripped by underfrequency relays. If the overvoltages are severe enough, they should be tripped as an integral part of the off-nominal frequency program.

Recommendation 7: To protect against overvoltages following an underfrequency load shedding event, systems shall implement automatic measures to maintain voltages within acceptable limits.

XIII. Direct Load Tripping

There may be specific disturbances for which load needs to be tripped faster than afforded by an UFLS program to adequately arrest frequency and avoid cascading. This may be required either for regional or local needs. The program should allow such actions as long as it enhances and does not compromise the overall uniform program.

Direct load tripping can be accomplished by sending trip signals to shed load based on pre-programmed logic or by using UFLS relays with frequency set points above 59.1 Hz. If a direct load tripping scheme employs UFLS relays, the load scheduled to be shed at the designated high frequency set points can be counted toward the 59.1 Hz UFLS plan requirement.

Recommendation 8: Direct load tripping is allowed if it complements the Coordinated Plan (see Recommendation 2G).

XIV. WSCC Security Coordinators

CMOPS recommends that each Security Coordinator (WAPA, APS, PG&E and BPA) develop comprehensive and detailed guides for the restoration of load following a load shedding event. While MORC gives clear guidelines in this regard, nevertheless the experience with the disturbances of July and August 1996 indicate that more coordination and clarification is needed.

Recommendation 9: Each of the 4 Security Coordinators shall develop comprehensive and detailed guides for the restoration of load following a load shedding event.

XV. Relationship to Other WSCC Initiatives

A separate effort is underway within WSCC by the Controlled Islanding ad hoc Task Force to determine if the formation of islands can be “controlled.” The recommendations contained in this report are independent of the upcoming recommendations from the Controlled Islanding ad hoc Task Force. If the formation of islands can be controlled, then there will still be a uniform off-nominal frequency program within that island. If the islands are not controlled or do not form as intended, there will be a uniform off-nominal frequency program in whatever islands form. If no islands are formed, then there will be a uniform program throughout all of WSCC.

As previously discussed, another group within WSCC is evaluating whether there should be direct load tripping by the users of COI for a COI outage. If sufficient direct load tripping is recommended, then the generation/load imbalance in the southern island will not result in frequency deviations below 59.1 Hz and underfrequency load shedding will not occur if Plan 59.1 is adopted. Thus, the recommended UFLS program specified as Recommendation 2A is not affected. If direct load tripping is not implemented, then there will be a uniform program (Plan 59.1 or Plan 59.3) for the entire southern island. For contingencies other than COI, there will be a uniform program throughout WSCC.

XVI. Tables

The tables on the following pages reflect the UFLS assessments and stability results.

XVII. Attachments

The Attachments on the following pages include information referred to in the Report.

Reference B

Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Final Report

As discussed and approved by TSS on January 9, 2003

January 21, 2003

Prepared by:
Under-frequency Load Shedding Task Force

Dana Cabbell (SCE, Chair)
Irina Green (CAISO)
Tom Green (PSCO)
Pamela McLean (AIES)
Anatoliy Meklin (PG&E)
Mukesh Nagpal (BC Hydro)
John Phillips (Puget)
Steve Rueckert (WECC)
Joe Tarantino (SPPC)
Boris Tumarin (EPE)

I. Introduction

NERC's Planning Standard III.D.S2.M1 states "Each Region shall periodically (at least every 5 years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its Off-Nominal Frequency Plan." The WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan (Off-Nominal Frequency Plan) was approved and recommended for implementation in 1997 in response to the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Electricity Coordinating Council (WECC) transmission system. The 1997 final report has been provided in Appendix 1 of this report.

Being five years since the implementation of WECC's Off-Nominal Frequency Plan, the Technical Studies Subcommittee (TSS) at the September 2001 meeting, formed an UFLS Task Force, assigned to perform the technical analysis to determine if WECC's Off-Nominal Frequency Plan is still effective in arresting a system frequency decline due to a system-wide disturbance.

The UFLS Task Force's assignment was expanded in scope to include the evaluation of the impact on the Off-Nominal Frequency Plan due to the frequency protection design requirements for new combustion turbines. The existing WECC Off-Nominal Frequency Plan established requirements for generators off-nominal frequency relay protection settings for under- and over- frequency operation.

According to a generator manufacturer's presentation to the UFLS Task Force, some of their new gas turbine designs do not meet the existing WECC Off-Nominal Frequency Plan requirements for a generator unit to stay connected to the electric system for low frequency events. These new gas units have an instantaneous trip design of 58.2 Hz; the WECC Off-Nominal Frequency Plan does not allow for an instantaneous trip until the frequency declines down to 56.4 Hz. In discussions with another generator manufacturer, it was reported that the under-frequency protection for their gas turbines requires an instantaneous trip of the unit at 57 Hz. However, the existing Off-Nominal Frequency Plan has a provision when a generator unit does not meet the generator under- frequency requirements. The plan states that "Systems that have generators that do not meet the requirements in Item 5A must automatically trip load …… to match the anticipated generation loss…" (1997 Off-Nominal Frequency Load Shedding and Restoration Plan, page 6, Item 5B).

Similarly for the over-frequency requirements, some new gas turbines are designed to trip during an over-frequency event sooner than the WECC Off-Nominal Frequency Plan allows.

The work plan of the UFLS Task Force to complete their assignment is summarized below:

Task 1:

- Test the Off-Nominal Frequency Plan by simulating the same disturbances as in the 1997 study – loss of WECC Northwest-Southwest intertie designated as the California-Oregon Intertie (COI), along with the operation of the Northeast-Southeast (NE/SE) Separation Scheme using the following data sets:
  - Generic data, which models the existing Off-Nominal Frequency Plan exactly as stated in the 1997 Coordinated Plan,
  - Actual UFLS data in the Master Dynamics File (MDF), and
  - Generic data using the ggov1 model for only the generator units identified as responsive units in the FRR studies.
  - Perform the analysis for high Southern Island and high Northern Island Import Scenarios.
- Review the UFLS data records in the WECC Master Data File (MDF)

Task 2:

- Identify the issues related to the more restrictive under- and over-frequency design of the combustion turbine units being placed in service on the WECC System.
  - Determine the impact to the Off-Nominal Frequency Plan of the generators that do not meet the under-frequency operation requirements
  - Identify options to mitigate the impact to the Off-Nominal Frequency Plan
  - Recommend next steps

II. Conclusions

<u>Task 1</u>

Conclusion 1: The Southern Import Scenario demonstrated the model of the existing coordinated WECC Off-Nominal Frequency Plan was effective in arresting the frequency decline and in meeting the Plan's objective. Actual operation depends on the physical implementation of the Plan.

Conclusion 2: A survey was sent to WECC's Area Coordinators to review the Off-Nominal Frequency load shedding data records and to populate the database with accurate data for the Off-Nominal Frequency Plan of the member utilities in their respective area(s). To date, the survey results have not been collected from each Area Coordinator. An additional request to the Area Coordinators who haven't responded will be required from the

TSS Chairman. The review and update of the Off-Nominal Frequency load shedding data records is a NERC Standard IIID.S1.M1 requirement. It needs to be noted that with updated data, the results from the simulation of the Off-Nominal Frequency Plan will be based on how each member system models its Plan.

Conclusion 3: The Northern Import Scenario demonstrated the model of the existing coordinated WECC Off-Nominal Frequency Plan was effective in arresting the frequency decline and in meeting the Plan's objective. Actual operation depends on the physical implementation of the Plan.

Conclusion 4: The Northwest Power Pool (NWPP) Plan is still effective at arresting a frequency decline when the Direct Load Trip (DLT) elements are unavailable during expected import conditions, however at reduced import levels.

Conclusion 5: For scenarios studied, a 30% resource loss resulted in a frequency decline to 57.8 Hz as the lowest frequency. The event evaluated is a severe scenario, but may not be the worst case for each island simulated.

Task 2

Conclusion 6: Based on manufacturer information, some new combustion turbine designs are not meeting the Off-Nominal Frequency Plan requirement for a generator unit to stay connected to the electric grid for frequency excursions. However, the existing Off-Nominal Frequency Plan requires systems that have generator units that do not meet the generator under-frequency requirements (i.e., have higher frequency trip settings than the Off-Nominal Frequency Plan) to trip the equal amount of load to the amount of generation tripped.

Conclusion 7: The existing Off-Nominal Frequency Plan would have to be changed significantly to keep the frequency decline from going below 58.2 Hz for a 30% resource loss. The UFLS Task Force does not recommend increasing the amount of load shedding to accommodate the 58.2 Hz settings. If the manufacturers don't confirm ability to operate below the 58.2 Hz, the WECC system will be limited in its controllability and operability to maintain system reliability.

Conclusion 8: Based on the Equivalent System Analysis, the existing UFLS system would handle a 30% resource loss if the manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust protection allowing immediate trip only at 57.8 Hz.

Conclusion 9: Based on the Equivalent System Analysis, if the study basis for the Off-Nominal Frequency Plan was adjusted from a 30% resource loss to a 20-27% resource loss, the frequency decline may be above the 58.2 Hz. This new resource loss assumption would need to be tested using WECC base cases.

III. Recommendations

Recommendation 1: Re-evaluate the Off-Nominal Frequency Plan once the data to populate the ggov1, lcfb1 (turbine load controller), and AGC models has been developed and tested.

Recommendation 2: TSS Chairman should send a letter to the Area Coordinators who have yet to submit their review and update of the off-nominal frequency data records, requesting their information to be sent to WECC Staff.

Recommendation 3: Manufacturers perform a risk assessment of their units to operate between 59.5 and 57.8 Hz during time intervals achievable by the actions of the existing Off-Nominal Frequency Plan.

Recommendation 4:

A) Investigate if the generation requirement settings could be adjusted to reflect an instantaneous trip at a higher frequency level than 56.4 Hz.

B) Adjust the format of the generation requirement table from the 1997 Off-nominal Frequency Plan (page 6, item 5A, Appendix 1) to remove the 0.1 Hz gaps according to the Compliance Monitoring and Operating Practices Subcommittee (CMOPS) interpretation.

Recommendation 5: Perform an analysis testing the coordinated UFLS Plan assuming a 20-25% loss of resources. This should be performed after the data to populate the ggov1 governor and lcfb1 (turbine load controller) models have been developed and tested. The impact on system security should be evaluated due to this change in the basis for the UFLS Plan's design.

Recommendation 6: Form a task force reporting to Joint Guidance Committee (JGC) to review the policy options and issues related to some new combustion turbine design not meeting the existing Off-Nominal Frequency Plan's generation under- and over-frequency requirements.

IV. Task 1 Summary: Technical Analysis Testing the Existing WECC Coordinated Off-Nominal Frequency Plan

A. Southern Import Scenario

To test the Off-Nominal Frequency Plan for a Southern Import Scenario, the loss of COI, along with the operation of the NE/SE separation scheme, and the additional loss of generation resources in the Southern Island resulting in a 30% loss of total resources (imports plus generation) was simulated using a WECC approved 2002 Heavy Summer case. This is the same contingency and assumed resource loss used to design the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan in 1997.

Generic UFLS data, which models the Off-Nominal Frequency Plan, was used for this initial test.

Column 1 in the attached Table 1, along with the Frequency Plot 1 shown in Appendix 2 summarizes the results of this test. As shown, the Off-Nominal Frequency Plan arrested the frequency decline, and the frequency stalled at 59.7 Hz.

The same contingency analysis and generation loss assumption was performed using the same WECC approved 2002 Heavy Summer case, with a modified dynamics data set with the ggov1 governor model used only on the generation units identified as being responsive in the FRR studies. All other thermal governors were blocked. Column 8 in the attached Table 1, along with the Frequency Plot 3 in Appendix 2 summarizes the result of this sensitivity. The Off-Nominal Frequency Plan, again arrested the frequency decline, but the response is slower and the stalling frequency is lower at 59.3 Hz than the first test using the generic UFLS data and the existing governor model. The M&VWG has evaluated the new ggov1 model and has received approval from TSS. PCC Chairman has sent a letter to generator owners within the WECC grid requesting the data required to populate the new models.

Recommendation 1: Re-evaluate the Off-Nominal Frequency Plan once the data to populate the ggov1, lcfb1 (turbine load controller), and AGC models has been developed and tested.

The final sensitivity performed for the Southern Island case was to use the actual UFLS data files in the Master Data File (MDF). Column 7 in Table 1, along with the Frequency Plot 2 summarizes the results. The frequency decline was arrested and settled at 59.4 Hz.

Using the actual UFLS data records in the MDF highlighted numerous load-shedding records pointing to buses without load or buses that don't exist. These data records needed to be reviewed and updated. NERC Standard IIID.S1.M1 requires updating the Off-Nominal Frequency Plan database. To meet this requirement and to also ensure all UFLS load shedding records are pointing to load buses, or existing buses, the UFLSTF sent a request to all WECC Area Coordinators to review the UFLS data records in their respective areas. Corrections to the data were due to the Task Force by July 22, 2002**.** The survey results have not been collected from each Area Coordinator. An additional request to the Area Coordinators who haven't responded will be required from the TSS Chairman.

Conclusion 1: The Southern Import Scenario demonstrated the model of the existing coordinated WECC Off-Nominal Frequency Plan was effective in arresting the frequency decline and in meeting the Plan's objective. Actual operation depends on the physical implementation of the Plan.

Conclusion 2: A survey was sent to WECC's Area Coordinators to review the Off-Nominal Frequency load shedding data records and to populate the database with accurate data for the Off-Nominal Frequency Plan of the member utilities in their respective area(s). To date, the survey results have not been collected from each Area Coordinator. An additional request to the Area Coordinators who haven't responded will be required from the TSS Chairman. The review and update of the Off-Nominal Frequency load shedding data records is a NERC Standard IIID.S1.M1 requirement. It needs to be noted that with updated data, the results from the simulation of the Off-Nominal Frequency Plan will be based on how each member system models its Plan.

Recommendation 2: TSS Chairman should send a letter to the Area Coordinators who have yet to submit their review and update of the off-nominal frequency data records, requesting their information to be sent to WECC Staff.

B. Northern Import Scenario

To test the Off-Nominal Frequency Plan for a Northern Import Scenario, the loss of COI, along with the operation of the NE/SE separation scheme, and the additional loss of generation resources in the Northern Island resulting in a 30% loss of resources (imports plus generation) was simulated using a WECC approved 2001-02 Light Winter case. This is the same contingency and assumed resource loss simulated for the Southern Import Scenario and used to design the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan in 1997.

Generic UFLS data, which models the Off-Nominal Frequency Plan as stated in the Off-Nominal Frequency Plan was used for this initial test.

Column 1 in the attached Table 2, along with Frequency Plots 1 and 2, located in Appendix 3 summarizes the results of this test. As shown, the Off-Nominal Frequency Plan arrested the frequency decline, and the frequency stalled at approximately 59.6 Hz.

The same contingency analysis and nearly identical amount of generation loss assumption was performed using generic UFLS data modified to reflect the NWPP modified Off-Nominal Frequency Plan. The Northwest has identified the need to trip more load at a higher frequency than is called for in the WECC Off-Nominal Frequency Plan. Column 2 in the attached Table 2, along with Frequency Plots 3 and 4, located in Appendix 3 summarizes the results of this test. As shown, the NWPP modified plan also arrested the frequency decline, and the response is slightly faster and the stalling frequency is higher at about 59.75 Hz

Conclusion 3: The Northern Import Scenario demonstrated the model of the existing coordinated WECC Off-Nominal Frequency Plan was effective in arresting the frequency decline and in meeting the Plan's objective. Actual operation depends on the physical implementation of the Plan.

BPA performed additional studies to evaluate a change in the Northwest Power Pool's (NWPP) Modified UFLS Plan (NWPP Plan) for a northern island import scenario. The change in the NWPP Plan consisted of the Direct Load Tripping (DLT) elements being removed. The scenario tested under-frequency load shed performance for the Northwest control area, after the loss of the Northwest-Montana ties, the Northwest-Idaho ties, and the California-Oregon Intertie (COI). The resource loss covered a range from 24% to 31% for the resulting a control area, which kept the British Columbia Hydro (BCH) system connected to the Northwest (NW) area.

The studies were performed using a 1998 Light Winter WECC base case modified to represent the expected 2001 Light Winter conditions.

The generic relay data that represent the WECC's Off-Nominal Frequency Plan was changed according to the NWPP description. The DLT[1] components of the NWPP Plan were removed to reflect the status of the Direct Load Service Industry (DLSI) being shut down.

[1] *Puget Sound's 250 MW of DLT remain in service, but were removed for this analysis.*

The study results are summarized in the Table 3 with frequency plots for cases 57, 73, and 75 are located in Appendix 4. As shown in Table 3, the implemented Modified UFLSNWPP Plan with DLT unavailable arrested the frequency decline and stalled at around 58.25 Hz, with approximately 7400 MW of load shed. This load shedding equates to approximately 33% of the total area load shed for the resulting NW and BCH islands. Study cases 57, 73 and 75, found in Table 3 define the outer boundary region of the Northern Import Safety-Net area. The upper limit of the safety-net area without DLT is 5675 MW (COI = 3675 MW and the PDCI = 2000 MW). As DLT elements become available, this upper limit can be raised to 6775 MW, assuming the PDCI is returned to its full 3100 MW import level. The implied Safety-Net area is based on the relationship between the COI-PDCI and West-of-Borah paths.

Even with a reduction in the DSI load tripping, there still appears to be some frequency over- speed. Frequency recovery to 60.25 Hz is shown to occur about 7, and as long as 15 seconds, following the frequency minimum point. The results suggest a continued recovery to 60.0 Hz.

Conclusion 4: The Northwest Power Pool (NWPP) Plan is still effective at arresting a frequency decline when the Direct Load Trip (DLT) elements are unavailable during expected import conditions, however at reduced import levels.

Conclusion 5: For scenarios studied, a 30% resource loss resulted in a frequency decline to 57.8 Hz as the lowest frequency. The event evaluated is a severe scenario, but may not be the worst case for each island simulated.

V. Adjustments to the Off-Nominal Frequency Generation Requirements

Under-frequency Instantaneous Trip

Discussions have occurred surrounding the 56.4 Hz instantaneous trip under-frequency limit. The generation requirement table developed for the 1997 Off-Nominal Frequency Load Shedding and Restoration Plan (page 6, Item 5A) is repeated below as Table 5:

Table 5

Existing WECC Coordinated Off-Nominal Frequency Load Shedding Plan

Under-frequency Limit	Over-frequency Limit	Minimum Time
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operation)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
Less than 56.4 Hz	Greater than 61.7 Hz	Instantaneous trip

The requirement for generators to stay connected to the grid down to 56.4 Hz seems extreme based on the evaluation of the Off-nominal Frequency Plan performed as part of this report (Section IV). The UFLS Task Force's evaluation resulted in the lowest frequency to be 57.8 Hz (Table 1). The UFLS Task Force recognized this was a severe analysis, but may not be the worst case, since only one season for the Southern and Northern scenario was analyzed. Further analysis would be required to justify raising the instantaneous trip point and to determine the under-frequency limit at which an instantaneous trip is allowed. However, at this phase, that analysis was considered to be outside the scope of the study work for the UFLS Task Force.

As a benchmark, the Task Force evaluated other Regions' UFLS Plans. The attached Table 4 compares the different plans' generator requirements for staying online during system frequency excursions. The comparison illustrates that the 56.4 Hz level is extreme, since, all the councils surveyed but one allows a generator to instantaneously trip at 57 Hz.

Undefined Gaps in the Under-and Over-Frequency Limits

It was brought to the attention of the UFLS Task Force and of the Compliance Monitoring and Operating Practices Subcommittee (CMOPS) the range in the under- and over-frequency generation requirement (see table above) has a 0.1 Hz gap where the minimum time requirement is not defined. CMOPS interpretation was to require the generator to observe the longer minimum time requirement in the undefined gap. To make the table more understandable, the following change in notation was developed as shown in Table 5 below:

Table 6

Existing WECC Coordinated Off-Nominal Frequency Load Shedding Plan (New notation)

Under-frequency Limit	Over-frequency Limit	Minimum Time
> 59.4 Hz	60.0-< 60.6 Hz	N/A (continuous operation)
<=59.4 Hz	60.6-<61.6 Hz	3 minutes
<=58.4 Hz	61.6-<61.7 Hz	30 seconds
<= 57.8 Hz		7.5 seconds
<=57.3 Hz		45 cycles
<=56.8 Hz		7.2 cycles
<= 56.4 Hz	> 61.7 Hz	Instantaneous trip

Recommendation 5:

A) Investigate if the generation requirement settings could be adjusted to reflect an instantaneous trip at a higher frequency level than 56.4 Hz.

B) Adjust the format of the generation requirement table from the 1997 Off-nominal Frequency Plan (page 6, item 5A, Appendix 1) to remove the 0.1 Hz gaps according to the Compliance Monitoring and Operating Practices Subcommittee (CMOPS) interpretation.

VI. Task 2 Summary – Generation Under-frequency Protection Requirements

The existing WECC Off-Nominal Frequency Plan established off-nominal frequency relay protection settings for under- and over- frequency operation for generators to stay connected to the electric grid for specified time frames. Table 5 above in Section V displays the generator requirements as developed in the 1997 Off-Nominal Frequency Load Shedding and Restoration Plan (page 6, Item 5A).

In addition to the requirements for generators' off-nominal protection settings, the Plan stated that "Systems that have generators that do not meet the requirements in Item 5A must automatically trip load …… to match the anticipated generation loss…" (1997 Off-Nominal Frequency Load Shedding and Restoration Plan, page 6, Item 5B).

The basis for the generator under-frequency and over-frequency operation requirements is the ANSI/IEEE Standard c37.106-1987. This Standard included a composite requirement curve that was developed using the most restrictive limitations imposed by the manufacturers, while meeting a 5% loss of life criteria. The Standard is presently being revised and is in the final stages of review prior to being presented to IEEE balloting body for final approval

According to a generator manufacturer's presentation to the UFLS Task Force, some new gas turbine designs do not meet the existing WECC Off-Nominal Frequency Plan requirements for a generator unit to stay connected to the electric system for low frequency events. Some of their new gas units have an instantaneous trip design of 58.2 Hz; the WECC Off-Nominal Frequency Plan does not allow an instantaneous trip until the frequency declines down to 56.4 Hz. In discussions with another generator manufacturer, it was reported that the under-frequency protection for their gas turbines requires an instantaneous trip of the unit at 57 Hz. However, the existing Off-Nominal Frequency Plan has a provision when a generator unit does not meet the generator under- frequency requirements. The plan states that "Systems that have generators that do not meet the requirements in Item 5A must automatically trip load …… to match the anticipated generation loss…" (1997 Off-Nominal Frequency Load Shedding and Restoration Plan, page 6, Item 5B).

Similarly for the over-frequency requirements, some new gas turbines are designed to trip during an over-frequency event sooner than the WECC Off-Nominal Frequency Plan allows.

Conclusion 6: Based on manufacturer information, some new combustion turbine designs are not meeting the Off-Nominal Frequency Plan requirement for a generator unit to stay connected to the electric grid for frequency excursions. However, the existing Off-Nominal Frequency Plan requires systems that have generator units that do not meet the generator under-frequency requirements (i.e., have higher frequency trip settings than the Off-Nominal Frequency Plan) to trip the equal amount of load to the amount of generation tripped.

A. Simulations of Generation Loss using GE PSLF and WECC Base Cases

The UFLSTF performed simulations adjusting the Off-Nominal Frequency Plan to try and maintain the frequency decline above the 58.2 Hz to determine how the plan would have to be changed to accommodate the new gas unit's under-frequency protection requirements. The Southern Import Scenario was used.

The following 5 sensitivities were performed through adjusting the Off-Nominal Frequency Plan minimum load shedding blocks. For each block, the following increases in the frequency and load shed set points were tested:

1) Frequency trip point by 0.1Hz,

2) Frequency trip point by 0.2 Hz,

3) Percent load shed by 0.5%,

4) Percent load shed by 1%, and

5) Increase frequency trip by 0.1Hz/load shed by 1%.

Columns 2-6 in Table 1 and the Frequency Plots 4-8 in Appendix 2 illustrate that the frequency still dipped below the 58.2 Hz threshold for each of the 5 scenarios

Conclusion 7: The existing Off-Nominal Frequency Plan would have to be changed significantly to keep the frequency decline from going below 58.2 Hz for a 30% resource loss. The UFLS Task Force does not recommend increasing the amount of load shedding to accommodate the 58.2 Hz settings. If the manufacturers don't confirm ability to operate below the 58.2 Hz, the WECC system will be limited in its controllability and operability to maintain system reliability.

B. Simulation of Generation Loss using a Equivalent System Analysis

The Off-Nominal Frequency Plan was designed for a 30% loss of generation and the UFLSTF tested the plan at this level of generation loss using GE PSLF and the WECC cases. However, for the purpose of this study, many system model details are unnecessary, as the system can be assumed stable and operating with the same frequency in all of its parts. The more detailed analysis for various generation loss percentages (see “Off-Nominal Frequency Range Reduction Impact Assessment” in Appendix 5) was conducted with the simplified one-bus system model. This model allows multiple calculations without specifying particular generation loss scenarios, without changes in hundreds of the *UFLS* models and without numerical convergence problems. The comparison of the results of the identical simulation with this simplified one-bus system frequency model and with the GE PSLF/WECC model shows satisfactory accuracy of this Equivalent System analysis. The results for the same percent drop of generation for the Equivalent System analysis are slightly more optimistic because disturbances in the detailed scheme are additionally aggravated by the increase of system losses. Following is a summary of the “Off-Nominal Frequency Range Reduction Impact Assessment”:

1. The Existing WECC Coordinated Off-Nominal Frequency Plan. This plan specifies parameters of the load tripping blocks, which are able to prevent violations of the “5% loss of turbine life” criteria for a maximum generation-load imbalance of 30%.

Table 7

Existing WECC Coordinated Off-Nominal Frequency Load Shedding Plan

UFLS-A - instantaneous UFLS (<u><</u>14 cycles)	*UFLS-B* - anti-stalling UFLS
Block 1 - 59.1 Hz, 4.75%,	Block 1 – 59.3 Hz, 2%, 15 sec.
Block 1 - 58.9 Hz – 5.25%,	Block 2 – 59.5 Hz, 1.5%, 30 sec.
Block 1 - 58.7 Hz – 5.75%,	Block 3 – 59.5 Hz, 1.78%, 60 sec.
Block 1 - 58.5 Hz – 6.0%,	
Block 1 - 58.3 Hz – 6.0 %	

2. There was a lot of confidence that the recommended Off-Nominal Frequency Plan is able to prevent damaging frequency dips and turbine protective trips. This confidence was based on two factors:
   a. The “5% loss of life” requirements were developed using the most restrictive limitations imposed by manufacturers.
   b. The Plan was developed with the assumption that the minimum permissible dynamic frequency is 57.9 Hz instead of 56.5 Hz, required by the “5% loss of life” criteria.

3. The Existing WECC Coordinated Off-Nominal Frequency Plan *UFLS-A*[2] provides $f_{settling}$=58.2 Hz on about 29.9% loss of generation ($\Delta P_{Gen.Loss}$). Even with this reduced $\Delta P_{Gen.Loss}$, system performance does not satisfy generators' under-frequency requirements, because frequency stalls at 58.2 Hz and stays at this level for about 15 sec. until initiation of *UFLS-B*.

4. The "58.2 Hz" generator under-frequency requirements are satisfied for $\Delta P_{Gen.Loss} \leq 27.5$ %, if this $\Delta P_{Gen.Loss}$ is sufficient to trigger all five blocks of *UFLS-A*. If $\Delta P_{Gen.Loss}$ = 27.5 %, frequency comes closely to 58.2 Hz, but does not stall and immediately rebounds, reaching 59.0 Hz for 15 sec.The new frequency limitations are not ordinary for the existing *UFLS* design and require verification of system performance for moderate values of $\Delta P_{Gen.Loss}$. System frequency may stall in "blind spots" between settings of two blocks of *UFLS-A* for 15 sec. until *UFLS-B* trips additional load[3]. This verification is not necessary with the "5% loss of life" limitations, allowing 15-sec. operation in all possible "blind spots".

6. The developed "*UFLS Can Handle*" table (Table 8) gives maximum durations of system operation with different off-nominal frequencies, which might be caused by $\Delta P_{Gen.Loss} \leq 27.5$ % or $\Delta P_{Gen.Loss} \leq 30$ % in the WECC system, equipped by existing *UFLS*. These durations represent the abilities of particular UFLS system and should not be confused with any equipment limitations (such as 5% loss of life).

Table 8

UFLS Can Handle Table

f(Hz)	Time (sec) for Pgen.loss≤27.5%	Time (sec) for Pgen.loss≤30%
59.5	<34.0	<37.5
59.0	<25.0	<30.0
58.8	<22.2	<27.0
58.6	<20.0	<24.0
58.4	<14.0	<21.5
58.3	<6.2	<20.0
58.2	0.0	<19.5
58.0	0.0	5.5
57.8	0.0	0.0

[2] *UFLS-A* refers to the five fast acting blocks with different frequency settings and *UFLS-B* refers to the three anti-stalling blocks with different time delays.

[3] A value of $\Delta P_{Gen.Loss}$ belongs to a "blind spot" if this $\Delta P_{Gen.Loss}$ is barely covered by operation of some *UFLS-A* blocks, causing frequency stalling or its very slow restoration. The following block does not operate because of the insufficient frequency dip.

7. The existing UFLS system would handle $\Delta P_{Gen.Loss}$ = 30 % (second column in the Table), if the manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust protection allowing immediate trip only at 57.8 Hz. The 2.5% *UFLS* capability reduction (from 30 to 27.5%) would occur, if the manufacturers confirm[4] the time intervals only in first column of this Table.

8. Reduction of the time intervals in the UFLS Can Handle Table is also possible if actual manufacturer requirements happen to be more severe. The study considers three different options for such a reduction. However all of those options require readjustments and most likely modifications and replacement of some of the frequency relays.

9. It is very likely that system performance with existing (or increased by 2.5%) *UFLS* may satisfy the generator manufacturer's design specification for under-frequency operation. However, the correspondence between sizes of *UFLS* blocks, specified in the 1997 WSCC Off-Nominal Frequency Plan, and their actual sizes becomes very critical. This was not so critical for the "5% loss of life" conditions.

Conclusion 8: Based on the Equivalent System Analysis, the existing Off-Nominal Frequency Plan would handle a 30 % resource loss if the manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust protection allowing immediate trip only at 57.8 Hz.

Conclusion 9: Based on the Equivalent System Analysis, if the study basis for the Off-Nominal Frequency Plan was adjusted from a 30% resource loss to a 20-27% resource loss, the frequency decline may be above the 58.2 Hz. This new resource loss assumption would need to be tested using WECC base cases.

Recommendation 3: Manufacturers perform a risk assessment of their units to operate between 59.5 and 57.8 Hz during time intervals achievable by the actions of the existing UFLS Plan. Hz.

Recommendation 4: Perform an analysis testing the coordinated UFLS Plan assuming a 20-27% loss of resources. This should be performed after the data to populate the ggov1 governor, lcfb1 (turbine load controller), and AGC models have been developed and tested. The impact on system security should be evaluated due to this change in the basis for the UFLS Plan's design.

---

[4] There is no an available specification for turbine operation with frequencies above 58.2 Hz.

VII. Task 2 Discussion

Under-Frequency Discussion

The UFLSTF agrees that there are at least 3 different options for handling the issue of units that can't meet the existing under-frequency requirements

Option 1: In today's generation market, in some instances, generation owners do not have control over load to shed if their generator unit trips off-line prior to the 56.4 Hz requirement of the WECC Off-Nominal Frequency Plan. The Off-Nominal Frequency Plan could be modified to:

Require the control areas, rather than the owner of the generator, to shed load for any generators in their control area that do not meet the Off-Nominal Frequency Plan's requirements.

Issues 1:

a) Tripping load to solve the system impact of a generation tripping due to under-frequency is not a system reliability solution.
b) For independent control areas, would the buyer of the output set up load dropping?
c) Is this practical if the buyer of the generation output is not in the same control area as the unit or changes regularly?
d) How does a single unit control area implement load dropping?
e) Whether or not the generator is in the same control area as the new load to be tripped, the tripping of additional load to compensate for the non-compliant generator may be a retail service issue requiring the approval of the regulatory agency with jurisdiction over that load.

Option 2 Require the owners of generators that do not meet the Off-Nominal Frequency Plan requirements and do not have control over any load, to contract with a load serving entity to arm the appropriate amount of load to be shed so during a frequency excursion that results in the generator(s) tripping sooner than allowed for in the Off-Nominal Frequency Plan, load would be shed within the island.

Issues 2

a) With no established market for an independent generator to obtain under-frequency load shedding, how would the load customer be compensated for being dropped when the generator that tripped was not providing service to the control area in which the customer is connected? Would a tariff/ancillary service need to be developed to compensate the load tripped due to the generator unit not meeting the WECC minimum requirements for a generator to stay connected during under-frequency excursions?

b) What if the load contracted is already dropped during an under-frequency event before the system frequency declines to 58.2 Hz?

c) Should the generator manufacturers and their customers mitigate their non-compliance of the WECC Plan.

Option 3: Modify the basis of the design of the Off-Nominal Frequency Plan to withstand less than 30% generation loss.

Issues 3:

a) Lowing the resource loss basis for the WECC Coordinated Off-Nominal Plan creates holes in the safety-net aspect of the Plan and moves away from the concept of a Regional solution to an individual member-system solution.

b) What is the technical feasibility behind the 30% loss of resources and what are the risks to system security of reducing the amount of generation loss WECC plans for?

c) Reducing the basis for the technical analysis used to design the Off-Nominal Frequency Plan does not change the physical system. The extreme generation loss was chosen to force the system down through the under-frequency set points to determine where generation begins to trip off instead of load.

d) Use a MW value as opposed to a percent generation loss value? The concern is that as more load and corresponding generation is added to the system a fixed MW value would become a decreasing percentage of the system resources.

e) Would the transfer capability of the WECC Paths into particular areas be reduced due to a lower generation loss value used to develop the Off-Nominal Frequency Plan?

Option 4: Modify the existing WECC Coordinated Off-Nominal Frequency Plan so that the frequency excursion is arrested prior to reaching 58.2 Hz. As described in this report the current Off-Nominal Frequency Plan showed the frequency decline was arrested at just below 58.0 Hz. Preliminary studies indicate that a significant change in either the amount of load shed or raising the frequency set points, or a combination of both, would be required to arrest the frequency decline prior to 58.2 Hz.

Issues 4:

a. Should WECC require its members to add additional relays to meet the new Off-Nominal Frequency Plan requirements because of the manufacturers' under-frequency design of CT units?

b. Should WECC relax or change the Off-Nominal Frequency Plan to accommodate manufactures' under-frequency design of the new gas turbines? How far does WECC accommodate the generator manufactures redesign of their machines before the grid reliability/security is jeopardized?

c. Consider the gradual modification of the five-block UFLS structure with the 0.2 Hz increment to a structure with uniform load distribution between 59.1 and 58.3 Hz, with significantly smaller Hz increments. The Off-Nominal Frequency Plan with a uniform load distribution trips an accurate amount of load in the entire off nominal operating range. This allows some redundancy in a cumulative amount of load available for tripping at different frequencies and in total load, which Off-Nominal Frequency Plan could trip. The loss of resources beyond a 27.5% or 30% would not be an issue because this condition would be covered by the redundancy without a risk of an excessive load trip.

Over-Frequency Discussion

Some combustion turbine generators are designed to trip sooner than the Off-Nominal Frequency Plan allows. The table below is an excerpt from the Off-Nominal Frequency Plan, showing the minimum time requirements for generators during an over-frequency event.

Table 9

Existing WECC Over-frequency Requirements

Over-frequency Limit	Minimum Time
60.0-60.5 Hz	N/A (continuous operation)
60.6-61.5 Hz	3 minutes
61.6-61.7 Hz	30 seconds
Greater than 61.7 Hz	Instantaneous trip

Following are questions raised associated with the over-frequency operation of some combustion turbine units:

1. What is the appropriate mitigation for generation units that trip on over-frequency quicker than the Off-Nominal Frequency Plan allows?

2. Should mitigation be provided for all such generation, or should a limited amount of over-frequency tripping be accepted without mitigation because it would help relieve the frequency excursion and act as a safety net for unforeseen contingencies? If some tripping is acceptable, how much?

3. What safety nets, if any, are there for over-frequency excursions? If there are none, are they needed?

4. Does the Off-Nominal Frequency Plan require generator tripping during an over-frequency excursion?

5. The points below should be considered when responding the questions regarding the over-frequency operation of generating units:

a. It is not acceptable if a power system with a high percentage of thermal power plants is not able to prevent units from tripping on over-frequency. An over-frequency excursion should be prevented through governor action. The unit's governor effectiveness can be demonstrated through a simple simulation.

b. Over-frequency is a concern only in cases of islanding of the system, which has a large amount of hydro generation. The governor action of the hydro generators provides a slower generation reduction than the governors of thermal units, thus allowing a greater increase in the frequency of the island. This continuing increase in the frequency is not a problem for the hydro units, but for the thermal units.

c. One possible method to deal with the situation of certain generators tripping quickly during an over-frequency excursion is to implement a system safety net, which monitors the system frequency and its rate of change to trip pre-determined hydro generators before the over-frequency reaches the protection settings.

Recommendation 6: Form a task force reporting to the Joint Guidance Committee (JGC) to review the policy options and issues related to the new combustion turbine design not meeting the existing Off-Nominal Frequency Plan's generation under- and over-frequency requirements.

VIII. Enhancements to Existing Plan

A. Gradual Generation Loss Discussion

The existing UFLS is designed to provide immediate actions (UFLS-A) preventing a deep system frequency decline caused by a sudden and significant loss of generation. UFLS-B restores frequency to the non-dangerous level (59.5 Hz) if UFLS-A does not raise frequency to that level or an additional minor loss of generation occurs after frequency restoration.

This UFLS structure could be less effective for a more common gradual loss of generation. The analysis of UFLS performance on a gradual loss of generation is presented in Appendix 6. The main conclusions of this analysis are:

1. A part or all of UFLS-A blocks may not participate in balancing a gradual generation loss because the leading UFLS-B actions prevent deep frequency declines.

2. When some UFLS-A blocks do not participate, 6% of system load connected to UFLS-B (20% of UFLS-A) is not enough to prevent frequency stalling at 58.7 Hz or even lower.

3. The possible solution, preventing frequency stalling, is implementation of additional UFLS-B circuits for the trip of some loads, presently connected to UFLS-A.

4. The Task Force agreed that adjusting the existing program to capture the impact of a gradual generation loss is a long-term betterment of the UFLS Program

5. If an area sees the potential of gradual generation loss, they should investigate changing their area program.

6. If an area is concerned with gradual generation loss, when entities within the area are changing relays, add ones that have many outputs to implement such a adjustment to the program.

Table 1
UFLS Study Results
Lowest Frequency Points
Southern Import Scenario

	1	2	3	4	5	6	7	8
	UFLS Load Shedding Representation							
Bus	Generic Data Representing Existing Plan	Increase Freq. Trip Points by .1 Hz	Increase Freq. Trip Points by .2 Hz	Increase Load Shed by 0.5%	Increase Load Shed by 1.0%	Increase Freq. Trip Points by .1 Hz and Load Shed by 1.0 %	Using Existing UFLS Data In MDF	Existing Plan with GGOV1 at Responsive Units
Lugo 500	58.193	58.279	58.395	58.226	58.266	58.360	58.169	58.068
Tesla 500	58.158	58.241	58.366	58.209	58.274	58.361	58.123	57.989
Westmesa 345	58.091	58.156	58.254	58.124	58.157	58.236	58.110	57.982
Kyrene 500	58.121	58.204	58.313	58.153	58.194	58.280	58.166	58.016
Ten Lowest	57.858	57.894	57.950	57.864	57.885	57.925	57.964	57.730
	57.919	58.006	58.056	57.958	57.992	58.042	57.967	57.810
	57.929	58.012	58.080	57.968	58.003	58.045	57.969	57.815
	57.937	58.012	58.080	57.968	58.003	58.050	57.972	57.824
	57.939	58.012	58.080	57.970	58.003	58.050	57.976	57.827
	57.947	58.012	58.080	57.972	58.003	58.050	57.979	57.828
	57.957	58.012	58.080	57.978	58.003	58.050	57.981	57.833
	57.967	58.016	58.083	57.978	58.013	58.050	57.985	57.838
	57.967	58.017	58.103	57.978	58.021	58.070	57.993	57.841
	57.967	58.020	58.117	57.978	58.022	58.082	57.994	57.843
Total Load Shed by UFLS	25534	25404	26231	27770	29310	28983	22117	26765

Table 2
UFLS Study Results
Lowest Frequency Points
Northern Import Scenario

Bus	UFLS Load Shedding Representation	
	Generic 59.1 Plan	Modified NW 59.3 Plan
Langdon 500	58.378	58.372
Ingledow 500	58.467	58.468
Coulee 500	58.418	58.561
Malin 500	58.396	58.610
Midpoint 500	58.396	58.679
Colstrip 500	58.425	58.630
Bridger 345	58.368	58.682
Pawnee 230	58.451	58.484
Camp Wil. 345	58.286	58.603
Ten Lowest Frequencies in the Northern Island	58.104	57.990
	58.125	58.017
	58.144	58.066
	58.160	58.072
	58.166	58.074
	58.168	58.075
	58.168	58.076
	58.168	58.077
	58.168	58.078
	58.170	58.100
Resources Lost	12,867 MW	12,898 MW
Total Load Shed by UFLS	12,110.1 MW	12,608.2 MW

Table 3
Frequency Response Summary Table
Modified UFLS Plan – BPA Analysis

Outage: Staged Northwest-Montana, Northwest-Idaho and COI opening

						Northwest Substations							
Case	**WOB**	**MPC**	**COI (3)**	**Resource -Loss**	**Resource -Loss (2)**	**Big Eddy 500kv**	**Garrison 500kv**	**Ingledow 500kv**	**Malin 500kv**	**Midpoint 345kv**	**Over-frequency**	**Total Load-shed**	**Comments**
#	**MW**	**MW**	**MW**	**MW**	**%**	**Hz**	**Hz**	**Hz**	**Hz**	**Hz**	**Hz**	**MW**	
75	1446	1893	2633	**5972**	26%	58.39	58.50	58.52	58.45	58.46	60.25	7380	Recovering to 60 Hz
74	1811	1925	2536	**6272**	28%	58.36	58.45	58.51	58.42	58.42	60.25	7382	Recovering to 60 Hz
73	1807	1924	1535	**5266**	23%	58.52	58.63	68.68	58.57	58.61	60.40	7063	Recovering to 60 Hz
72	1811	1946	2537	**6294**	28%	58.30	58.40	58.44	58.36	58.37	60.00	8125	Recovering to 60 Hz
69	1674	1915	2550	**6139**	27%	59.25	59.15	59.26	?	59.23	?	2531	Collapsed
57	1329	1950	3726	**7005**	31%	58.27	58.30	58.30	58.27	58.22	**59.88**	7477	Recovering
56	1256	1935	3423	**6614**	29%	58.29	58.38	58.40	58.33	58.28	?	8061	Collapsed
52	1821	2012	2500	**6333**	28%	57.39	57.29	57.89	57.79	57.82	?	16297	Collapsed
51	1839	1987	1539	**5365**	24%	58.48	58.55	58.60	58.54	58.54	60.25	9085	Recovering to 60 Hz
47	1563	1967	2340	**5870**	26%	58.29	58.42	58.46	58.36	58.39	?	7858	Collapsed
45	1238	1929	2749	**5916**	26%	58.28	58.43	58.47	58.36	58.38	?	7858	Collapsed

Note: Substations are located at the boundary regions of the Northwest area.

(2) Resource-loss Percentage is based on area load total for the Northwest (22618 MW)

(3) PDCI south-to-north transfers are set at 2000 MW

Table 4
Summary of Reliability Councils UFLS Programs

	Percent Load Shed											
Council	59.7 Hz	59.5 Hz	59.4 Hz	59.3 Hz	59.1 Hz	58.9 Hz	58.8 Hz	58.7 Hz	58.5 Hz	58.3 Hz	58.2 Hz	Freq. Generator Allowed to Trip
NPCC	10%						15%					57 Hz
ERCOT				5%		10%			10%			57.5 Hz
MAAC				10%		10%			10%			<57.5 Hz
ECAR		5%		5%	5%	5%		5%				<58.2 Hz
FRCC	9%		7%		7%		6%		5%		7%	<57.5 Hz
WSCC					5.3%	5.9%		6.5%	6.7%	6.7%		56.4 Hz

Appendix 1

WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

1997

WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Final Report

November 25, 1997

Prepared by

Underfrequency Issues Work Group *
Technical Studies Subcommittee

* Steven Mavis (CAISO, Chairman)
Joaquin Aguilar (EPE)
Duane Braunagel (PRPA)
Barry Francis (BEPC)
Chris Oakley (TAUC)

Table Of Contents

I. Executive Summary

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

In the aftermath of the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Systems Coordinating Council (WSCC) electrical transmission system, a group of WSCC members performed comprehensive assessments culminating in two reports: the "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996," and "WSCC Disturbance Report For the Power System Outage that Occurred on the Western Interconnection on August 10, 1996" (Disturbance Reports). In the Disturbance Reports' recommendations, several reliability issues were identified for further investigation. One of the reliability issues involves the efficacy of existing off-nominal frequency related policies and procedures (e.g. underfrequency load shedding (UFLS) programs) to arrest potential system collapses due to large frequency deviations and minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operation.

Recommendations in the Disturbance Reports request the Council to undertake a complete review of its members' underfrequency load shedding programs. Specific areas to be evaluated include coordination with generator off-nominal frequency protection requirements, coordination of automatic and manual load restoration, and coordination between and within regions.

On November 8, 1996, the Technical Studies Subcommittee (TSS) formed the ad hoc Underfrequency Issues Work Group (UIWG) to respond to the recommendations in the Disturbance Reports related to underfrequency issues. The general assignment given to the UIWG is summarized as follows:

- Determine if a uniform off-nominal frequency program can be specified for all of the Council.
- If yes, recommend a uniform off-nominal frequency program
- Recommend a policy regarding the automatic restoration of load
- Recommend a policy regarding the intentional tripping of tie lines and generators due to underfrequency

The UIWG has completed a comprehensive assessment of underfrequency issues to complete its general assignment and more. General principles including a specific UFLS plan have been developed as part of the overall assessment and formally documented herein. This assessment incorporates comments received from the Planning Coordination Committee, the Operations Committee, the Technical Studies Subcommittee, the Compliance Monitoring and Operating Practices Subcommittee, and the Technical Operation Subcommittee. These same Committees and Subcommittees approved the Final Draft of the assessment dated June 17, 1997, at their respective meetings during the summer of 1997. Though the Operations Committee approved the Final Draft at their June 1997 meeting, their approval was conditional, requiring Operations Committee members to review the Final Draft's Coordinated Plan and determine if the Plan could be implemented to their satisfaction.

To facilitate the review and implementation process, the Operations Committee formed the Underfrequency Program Implementation Task Force. After a review and comment period lasting roughly 30 days, the Underfrequency Program Implementation Task Force met in early September 1997 to amend the recommendations of the Coordinated Plan. The Operations Committee and the Planning Coordination Committee approved the amended Coordinated Plan at the September 1997 meeting and the October 1997 meeting, respectively. This Final Report of the "WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan" incorporates the amended Coordinated Plan as approved by the Operations Committee and the Planning Coordination Committee. On December 4, 1997, the WSCC Board of Trustees approved the Coordinated Plan.

It is recognized that specific details of compliance with implementing the Coordinated Plan need to be developed over time within the appropriate WECC groups.

The UIWG would like to acknowledge the contributions of many groups and individuals, on both the planning and operating sides of the WECC, for the successful completion of this assessment, culminating in the Coordinated Plan. As a quick reference for the reader, the Coordinated Plan is listed on the following 3 pages.

Coordinated Plan

1 There should be a coordinated off-nominal frequency program throughout all of WECC. Local differences are permitted as long as it can be demonstrated that the Coordinated Plan is not adversely effected.

2A The Council should adopt the 59.1 Hz Plan as a minimum standard.

Load Shedding Block	% of customer load dropped	pickup (Hz)	tripping time
1	5.3	59.1	-
2	5.9	58.9	-
3	6.5	58.7	-
4	6.7	58.5	-
5	6.7	58.3	-
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

2B The system average total tripping (relay & breaker) time should be no more than 14 cycles at the indicated frequency set points.

2C Intermittent load shall not be used unless monitoring is in place to allow changes in real time to accommodate the availability of the intermittent load and ensure the load shedding requirements of the Coordinated Plan are met.

2D Additional load can be tripped at frequencies higher than 59.1 Hz provided it does not violate the MORC or adversely impact neighboring systems. Frequency overshoot must be adequately addressed.

2E It is not permissible to start shedding load at frequencies lower than 59.1 Hz or to trip less load than called for by the Coordinated Plan.

2F Additional frequency set points can be used provided the cumulative total load shedding amounts meet the requirements of the Coordinated Plan for each of the Plan's frequency set points.

2G Where programs differ from the Coordinated Plan, member systems are responsible for conducting studies to verify compliance with the Plan. These studies will be reviewed by the Underfrequency Implementation Task Force.

3A All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WECC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration.

3B To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational.

4 Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one-second-time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

5A Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames:

Underfrequency Limit	Overfrequency Limit	Minimum Time
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operating range)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

5B Systems that have generators that do not meet the requirements in Item 5A must automatically trip load (in addition to that required in Item 2A) to match the anticipated generation loss and at comparable frequency levels.

5C All systems that own/operate generating facilities shall provide data to WECC regarding the off-nominal frequency protection settings of their units. Any changes in settings shall also be reported.

6A Only solid state and/or microprocessor underfrequency relays shall be used as part of the Coordinated Plan. Only load tripped by solid state and/or microprocessor underfrequency relays will be considered when determining compliance with the Coordinated Plan.

6B Only solid state and/or microprocessor frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz.

6C All frequency relays shall use the definite time characteristic and should not be disabled for voltages 80% of nominal or higher but can be disabled for voltages below 80% of nominal (at the discretion of the setting entity).

6D Electro-mechanical frequency relays can be used only for settings outside the 57.9-61.0 Hz range.

7 To protect against overvoltages following an underfrequency load shedding event, systems shall implement automatic measures to maintain voltages within acceptable limits.

8 Direct load tripping is allowed if it complements the Coordinated Plan (see Item 2G).

9 Each of the Reliability Coordinators shall develop comprehensive and detailed guides for the restoration of load following a load shedding event.

II. Background

In the aftermath of the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Systems Coordinating Council (WSCC) electrical transmission system, a group of WSCC members performed comprehensive assessments culminating in two reports: the "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnection on July 2, 1996 and July 3, 1996," and "WSCC Disturbance Report For the Power System Outage that Occurred on the Western Interconnection on August 10, 1996" (Disturbance Reports). In the Disturbance Reports' recommendations, several reliability issues were identified for further investigation. One of the reliability issues involves the efficacy of existing off-nominal frequency related policies and procedures (e.g. underfrequency load shedding (UFLS) programs) to arrest potential system collapses due to large frequencies deviations and minimize associated adverse impacts caused by cascading outages, and aid in quickly restoring the system to normal operation.

Recommendations in the July and August disturbance reports require WSCC to undertake a complete review of its members' underfrequency load shedding programs. Specific areas to be evaluated include coordination with generator off-nominal frequency protection requirements, coordination of automatic and manual load restoration, and coordination between and within regions.

III. General Assignment

The Technical Studies Subcommittee (TSS) formed the ad hoc Underfrequency Issues Work Group (UIWG) on November 8, 1996 to address the underfrequency issues identified in the Disturbance Reports. The UIWG prepared a Underfrequency Issues Work Plan (Attachment 1) which defined the assignment in more specific detail, identified the deliverables, and outlined the general methodology for accomplishing the task. The general assignment is summarized as follows:

- Determine if a uniform off-nominal frequency program can be specified for all of WSCC
- If yes, recommend a uniform off-nominal frequency program
- Recommend a policy regarding the automatic restoration of load
- Recommend a policy regarding the intentional tripping of tie lines and generators due to underfrequency

IV. NERC and WECC General Policy and Guidelines

Both NERC and WECC present guidelines for proper design of an off-nominal frequency program.

Policy 4, Subsection D, Criteria of the NERC Operating Guides states the following:

"Systems and control areas shall coordinate the application, operation, and maintenance of protective relays on the bulk electric system, including the coordination of underfrequency load shedding relays. They shall develop criteria which will enhance their system reliability with the minimum adverse effect on the Interconnection. (C.II.D.)"

NERC Policy 5 in the Operating Manual titled Emergency Operations (Attachment 2), addresses the issues of generator protection, load restoration, frequency restoration, and regional coordination. The following statement from Policy 5 summarizes the overall objectives of the off-nominal frequency program:

"Each system, control area, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of that interconnection. The program shall be coordinated throughout the interconnection to prevent unbalanced load shedding which may cause high transmission loading and extreme voltage deviations."

Section 6.C of the Minimum Operating Reliability Criteria (MORC), dated March 1997 (Attachment 3), further clarifies the objectives and requirements of an off-nominal frequency program:

- Minimize the risk of total system collapse in the event of separation
- Protect generating equipment and transmission facilities against damage
- Provide for equitable load shedding among entities serving load
- Improve overall system reliability
- Leave the system in a condition to permit rapid load restoration and re-establishment of interconnections
- Should be matched to meet island area needs and coordinated within the island area
- Should coordinate with underfrequency protection of generating units
- Should coordinate with any manual or automatic action that can be expected to occur under conditions of frequency decline
- Should be based on studies of system dynamic performance, using latest state-of-the-art computer analytical techniques
- Should minimize the risk of further separation, loss of generation, or excessive load shedding accompanied by excessive overfrequency conditions
- Should incorporate automatic generator tripping or other remedial measures to prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage

Section 5.D of MORC (Attachment 3) specifies that restoration should begin by stabilizing the island and returning the system frequency to normal, synchronizing the islanded area with adjacent areas, and restoring customer loads as conditions permit. Start-up power should be provided to generating stations before customer load is restored.

V. Overall Study Objectives:

1. Be in total compliance with all Council and NERC policies or requirements.
2. Following an event that results in off-nominal frequencies, leave the system in such condition as to permit rapid load restoration, re-establishment of interconnections, and otherwise allow the dispatchers reasonable time to make "fine tuning adjustments" to restore the system to normal operation.
3. Develop a program that gives acceptable performance for a wide range of initiating disturbances.
4. Develop a program that is universal and does not have to be changed seasonally because of different load characteristics or patterns.
5. Have sound technical basis for recommendations , specifically demonstrating that the recommended uniform off-nominal frequency program:
    a. arrests frequency declines as good as or better and with less shedding of overall load compared to the status quo or other programs, and
    b. restores the system to nominal frequency and zeroed ACE in an expeditious manner, without violating equipment capabilities, and free of impediments.
6. Develop a coordinated off-nominal frequency program that factors in requirements of generators.

The WECC system will be treated as a "one world" interconnection. This assumption is made to ensure that the primary emphasis of the analysis will be to improve the overall WECC system performance.

VI. Uniform Program Policy

Not having a uniform or coordinated off-nominal frequency program throughout the Council has exacerbated the consequences of actual disturbances. For example, regional differences in the UFLS program caused additional islands to form during the July 2 disturbance. The Rocky Mountain area (CO/WY/UT) automatically begins to trip load at a higher setting of 59.3 Hz than the Desert Southwest area (CA/AZ/NM/NV) setting of 59.1 Hz. In the July 2 disturbance, the Rocky Mountain area initially separated with the Desert Southwest area. The generation and load imbalance resulting from the load shed in the Rocky Mountain area at 59.3 Hz caused a surge of power to the south across the NE/SE transmission boundary, overloading that interface and causing it to open in a cascading fashion. The council compiled a list of UFLS programs currently in place (Attachment 4), from which one can compare the differences between WECC areas and member systems programs.

It is recognized that during a disturbance, there may be some slight variations in frequency at any given instant in time between different areas of the interconnection. However, as long as the interconnection remains intact the frequency will essentially be the same throughout the interconnection. The disturbance within the interconnection could be caused anywhere in the interconnection. In general, at the inception of the disturbance there is insufficient time to determine who is "causing the problem" and assign a load shedding responsibility to that party.

No technical reasons could be identified or demonstrated that would preclude the adoption of a uniform off-nominal frequency program throughout the Council. A uniform program approach could avoid the adverse consequences caused by the uncoordinated operation of individual programs. It also reinforces the concept of mutual support and shared benefits of the Western Interconnection by recognizing that all entities that derive benefits from the positive aspects of being connected to the grid must also contribute their fair share in mitigating the negative aspects.

Though a uniform program appears technically feasible and desirable, it is recognized that such a program needs to have boundaries and be flexible. For example, some systems may have special procedures in place to avoid a blackout scenario if the frequency drops to critically low levels. To allow for tailored procedures at these low frequencies, the uniform program should be bounded by a minimum frequency. Also, there may be valid local reasons to shed load in excess of that required by regional requirements. In the Rocky Mountain area, southeast Colorado (including the Denver metro area) imports a considerable amount of power from remote areas. This geographical area also islanded during a spring ice storm. Hence, the decision was made by the affected systems to increase the amount of load shedding in this localized area. Surrounding areas had a decreased load shedding requirement. Another potential problem with a uniform program is that if the disturbance originates within a heavily importing area, then the flows will be increased with the potential of overloading the transmission ties. This should be evaluated on an individual basis. If a problem is suspected, the importing areas should increase the amount of load shed with a corresponding decrease in the supplying area.

It was recognized that a coordinated plan, which combines the best of uniform standards and the best of individual procedures, should be adopted by the Council. Overall, the coordinated off-nominal frequency program met the larger geographical area requirements while providing for local area needs. The flexibility to meet local requirements needs to be retained, while still providing for the overall regional requirements.

Recommendation 1: There should be a coordinated off-nominal frequency program throughout all of WECC. Local differences are permitted as long as it can be demonstrated that the Coordinated Plan is not adversely effected.

VII. WECC Uniform UFLS Plan

Assumptions regarding specific design parameters needed to be identified and used to provide a quantifiable assessment of a uniform UFLS plan. It is recognized that actual parameters may deviate somewhat from the assumptions listed below without compromising the program.

Assumption 1: The uniform UFLS plan should coordinate with the 5% loss of life of turbine blades recommendations as determined by generator manufacturers. Turbine blade loss of life is the most limiting of the off-nominal frequency restrictions imposed by the generating units.

A 0% loss of life criteria implies that the generators are not exposed to any off-normal frequency operation outside of the continuous band. Some generators have robust operating limits that permit operation within a relatively large bandwidth. Other regions like the Rocky

Mountain area have determined that an off-nominal frequency program could be developed using the relatively conservative 5% loss of life criteria. Designing an off-nominal frequency program to meet the 5% loss of life criteria is an aggressive goal, but nevertheless a realistic goal. Owners/operators of generating units are more likely to accept the potential for loss of life to their units if this risk is minimized to the greatest extent possible.

Determining the loss of life for frequency excursions is not an exact science. Nevertheless, the manufacturers have developed recommendations. These requirements are described in ANSI/IEEE Standard C37.106-1987, Guide for Abnormal Frequency Protection for Power Generating Plants (Attachment 5). A composite requirement was made using the most restrictive limitations imposed by any manufacturer. This is shown graphically in Figure 1 and in tabular form below.

Underfrequency Limit	Overfrequency Limit	Maximum Time
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operating range)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

One advantage of trying to meet the 5% loss of life criteria is that it allows all generation owners to protect their units per manufacturer recommendations. This is an additional reason why generation owners/operators should support this off-nominal frequency program.

Assumption 2: Sufficient load should be dropped in uniform UFLS plan to leave the system frequency within the continuous operating range of the generating units.

The generating units can operate continuously between 59.5 Hz and 60.5 Hz. It would be desirable to have the frequency following a disturbance that results in underfrequency load shedding to be restored within this range to minimize the potential for loss of life. This will allow the dispatcher time to analyze the situation and make appropriate adjustments to restore ties and the frequency to 60 Hz. If the frequency were left in the "time to damage" range of the generating units, immediate response is required of the dispatcher to be totally effective within minutes otherwise some generators may automatically trip to prevent further damage. This is both impractical and unnecessary.

Assumption 3: The uniform UFLS plan should provide coverage during a substantial loss of generation or resources (e.g. 25-33%).

A UFLS plan can be designed for a 50% range of generation overload. For example, a 33% loss of generation represents a 50% overload on remaining generation. A 50% loss of generation represents a 100% overload on remaining generation. A good off-nominal underfrequency program can be designed for a 0%-50% generation overload, a 25%-75% overload, or a 50%-100% overload. A program designed for a 50%-100% overload will not work at all for a contingency that involves only a 0%-50% overload.

The loss of 33% of total generation is, by any standard, a severe contingency. As a practical matter, a well behaved UFLS program cannot be designed for loss of generation beyond 33% unless load is massively over shed at high frequencies to prevent the dynamic frequency from falling below the point at which units trip instantaneously (56.5 Hz). This massive over shedding of load must then be accompanied by massive automatic and high speed load restoration to prevent the units from tripping due to overfrequency. The program designed for loss of generation beyond 33% will not work at all for loss of generation less than 33%. In view of these problems, the uniform off-nominal program should be designed up to a maximum generation and load imbalance of 33%.

Assumption 4: The minimum permissible dynamic frequency during a disturbance is 57.9 Hz. The maximum permissible dynamic frequency during a disturbance is 61.0 Hz.

Discussion: This minimum limit of 57.9 Hz was chosen because the allowable time of operation below 57.9 Hz to coordinate with the 5% loss of life criteria, is only 7.5 seconds. Intentional operation below 57.9 Hz was judged to be imprudent.

The maximum limit of 61 Hz was chosen because above this frequency some governors may go into an “emergency over speed mode” and close the main steam control valves. This causes the boiler to go into an “upset condition” and the unit will trip in the short term if the frequency is not reduced or may trip in the longer term because of the unstable boiler condition. A maximum frequency limit of greater than 61 Hz could have been chosen and still coordinate with the emergency controls of the governor, but as a practical matter the 61 Hz limit is easily achieved.

Assumption 5: Current UFLS plans utilize 5-6 steps, but a new and uniform UFLS plan need not be restricted to this number. The minimum separation between steps should be 0.1 Hz.

As a practical matter, it is just as easy to administer a 10 step UFLS plan as a 6 step program (per CMOPS, with the understanding that there will be an uniform UFLS plan throughout the Council). If we can get better performance with a 10 step UFLS plan than a 6 step program, then it ought to be considered. Absent any technical considerations, the preference would be to have fewer steps rather than more.

The underfrequency relay manufacturers provide set points in increments of 0.01 Hz. However, practical considerations suggest that the minimum separation between steps should be 0.1 Hz. Equipment instruction manuals for two relay manufacturers are provided (Attachment 6).

Assumption 6: Underfrequency relays have a maximum operating time of 6 cycles.

Relay manufacturers state that the minimum operating time of their equipment is 3.4 cycles. This is a hardware consideration. There are no advantages to having operating times longer than 6 cycles that incorporate some additional intentional detection time, and longer detection times or intentional time delay will destroy the integrity of the off-nominal program. It is the intent that additional time delay not be introduced beyond that inherent in the equipment itself.

Assumption 7: As a system average, a 6 cycle operating time of breakers is used to trip load.

Many systems will use distribution breakers to trip load. These distribution breakers are typically slower than transmission breakers. Although some systems will use transmission breakers to trip load, a system wide and conservative figure of 6 cycles will be used. This is not to imply that only breakers that operate in 6 cycles or less can be used in the UFLS plan. However, Assumptions 6 and 7 taken together imply that load will tripped 12 cycles after the frequency reaches the threshold level and that this 12 cycle operating time to trip the load is a system average. Moreover, there should be no intentional time delay introduced.

Assumption 8: If there is any discretion allowed, the preferred option is to have the post-disturbance frequency settle out above 60 Hz, as opposed to below 60 Hz.

If the frequency settles out above 60 Hz (but less than 60.5 Hz), then in short order the governors will automatically act to restore the system to 60 Hz. This will facilitate the restoration of ties (in the case of islanding) and in any event it is the preferred operating mode of the generators (to prevent spurious trips within the generating plant). If the frequency levels out below 60 Hz (but above 59.5 Hz), then governors will act to raise generation, however longer time delays are potentially possible because additional fuel must be added to boilers before the increased generation can be supported. There is also the possibility that increased generation may not be available, and load must be manually shed to achieve 60 Hz. A post-disturbance frequency of 60 Hz or slightly above is judged to maximize the dispatcher's ability to initiate system restoration activities.

Study Methodology:

An underfrequency disturbance event will typically have all load shed within 0.3 and 10 seconds after the inception of the disturbance. Governors will not operate to adjust MW output levels by any appreciable amount in this time frame, which means the frequency will change in accordance with the system inertial response characteristic. Looking at frequency alone, a simple model can be constructed using one equivalent generator supplying total system load (generator auxiliary power, losses, and customer load). The frequency response characteristics of load and generation are properly accounted for in this simple model. The simple model cannot account for transient variations in load resulting from transient variations in voltage. Whatever the voltage effect is, only the net generation and load imbalance affects the frequency.

A full network model using the transient stability program can include the effects of voltage on the load as well as losses during the dynamic time frame. The detailed program calculates the voltage profile resulting from a specific disturbance scenario, and presuming that the relationship between transient load and transient voltage is known, the net effect on the transient frequency can be determined. The detailed program can also show transient flows on the transmission system, and simulate islanding patterns.

The basic methodology is to use the simple equivalent model to develop a proposed uniform

UFLS plan. The equivalent model is explained in detail in the GE publication title "Load Shedding, Load Restoration, and Generator Protection Using Solid-state and Electromechanical Relays" (Attachment 7). This method is explained further in the WECC publication prepared by the Relay Work Group titled "Underfrequency Load Shedding Relay Application Guide" (Attachment 8).

This proposed UFLS plan is to be designed to accommodate a wide range of generator inertias and load/frequency characteristics. However, the program is to be optimized using the system average inertia and nominal load/frequency response characteristic.

The proposed UFLS plan resulting from the simplified analysis was "verified" using the full transient stability program. Base cases representing the December 14, 1994 and August 10, 1996 disturbances were used to confirm the adequacy of the proposed program.

The UFLS plan is able to meet Assumptions 1-8 identified above with generator inertia as low as 2.5 pu. and as high as 6.0 pu. The low inertia represents large steam units and the high inertia represents hydro units. The load sensitivity to frequency is the ratio between the percent load change to the percent frequency change. A system wide value of 1.5 is the recommended value in literature and is based on measurements. Because load decreases faster than frequency, the frequency settles out at some reduced value whenever there is a trip of generation. The off-nominal frequency program should meet the criteria identified above for load sensitivities as low as 1.0 and as high as 2.0.

The rationale for evaluating various values of equivalent generator inertia is that the mix of generation that trips during a disturbance is random, meaning that the mix of generation remaining after a disturbance is also random. This is especially true when the initiating disturbance can occur anywhere within the Council. The rationale for evaluating various load sensitivities is that the characteristics of load can change radically between seasons and geographic areas. The intent is to have a static off-nominal frequency program that does not change seasonally and will give acceptable performance for a wide range of initiating disturbances.

The UFLS plan is to be designed to meet the criteria specified above for losses of generation of 1%, 2%, 3%, 4%, 5%, 10%, 15%, 20%, 25%, and 30%.

Study Results:

The following two plans adhered to Assumptions 1-8 and gave acceptable performance for all combinations of generator inertia, load-frequency relationships, and generator-load imbalances. Plan 59.3 has the first load shedding block at 59.3 Hz, and Plan 59.1 has the first load shedding block at 59.1 Hz. Both options were prepared in recognition that the northern portion of WECC currently begins their UFLS plan at 59.3 Hz and the southern portion for the most part begins their UFLS plan at 59.1 Hz. In the simplified model, total load is comprised of customer load, losses, and generating station auxiliary power. A UFLS plan should not trip generating station auxiliary power and cannot directly affect losses (however system losses may go up or down following the disturbance). Therefore, there must be a relationship derived between total load and customer load. To derive this relationship, losses were assumed to 3% and generation auxiliary power to be 8% of gross generating station output. One unit of total load thereby becomes 1.12 units of customer load.

Plan 59.3

total load dropped (gross)	customer load dropped	pickup Hz	relay detection time-cycles	total tripping time-cycles
4.50%	5.06%	59.3	6	12
5.00%	5.62%	59.1	6	12
5.50%	6.18%	58.9	6	12
5.25%	5.90%	58.7	6	12
5.00%	5.62%	58.5	6	12
4.75%	5.33%	58.3	6	12
Additional automatic load shedding to correct underfrequency stalling				
2.00%	2.25%	59.3	-	15 sec
1.50%	1.69%	59.5	-	30 sec
1.78%	2.00%	59.5	-	1 min
Load automatically restored from 59.3 Hz block to correct frequency overshoot				
1.00%	1.12%	60.5	-	30 sec
1.50%	1.69%	60.7	-	5 sec
2.00%	2.25%	60.9	-	12

Plan 59.1

total load dropped (gross)	customer load dropped	pickup Hz	relay detection time-cycles	total tripping time-cycles
4.75%	5.33%	59.1	6	12
5.25%	5.90%	58.9	6	12
5.75%	6.46%	58.7	6	12
6.00%	6.74%	58.5	6	12
6.00%	6.74%	58.3	6	12
Additional automatic load shedding to correct underfrequency stalling				
2.00%	2.25%	59.3	-	15 sec
1.50%	1.69%	59.5	-	30 sec
1.78%	2.00%	59.5	-	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot				
1.00%	1.12%	60.5	-	30 sec
1.50%	1.69%	60.7	-	5 sec
2.00%	2.25%	60.9	-	12

A summary of the performance for the various combinations studied (using the equivalent inertia model) for both Plan 59.3 and 59.1 is provided in the tables section (XVI. Tables). Note that the generator inertia has no impact on the ultimate steady state frequency but does impact the rate at which these frequencies will vary. The most sensitive variable is the load/frequency response characteristic.

The load dropped at 59.5 Hz with a 30-second time delay and at 59.3 Hz with a 15-second time delay is an integral part of the program but also solves the problem experienced in the Rocky Mountain area during the July 2 disturbance. In this incident the first two steps of load shedding occurred, but over time additional generation tripped and the frequency gradually decayed to slightly below 59.4 Hz. This frequency is in the “time to damage” characteristic of some major generating units, and they were beginning to time out with a three minute delay. Fortunately, the frequency rose above the frequency threshold before the relays timed out, but this was mere coincidence and not a result of a deliberate action taken by the dispatchers to “beat the relay.”

In the simplified model, both plans yield acceptable and equivalent performance. Both plans have the same delayed trip at 59.5 Hz and 59.3 Hz, and the same automatic restoration at 60.5 Hz, 60.7 Hz, and 60.9 Hz. The plan beginning at 59.3 Hz utilizes six steps in the high speed portion tripping a total of 33.71% of customer load. The plan beginning at 59.1 Hz utilizes five steps in the high speed portion tripping a total of 31.17% of customer load. The difference in the amount of customer load tripped is indicative of the limited amount of time spent to “optimize” each plan, and if this difference is significant then additional effort should be made in this area.

Some customers self-protect themselves and trip their load automatically at frequencies higher than either 59.3 Hz or 59.1 Hz. Some utilities trip their interruptible load at frequencies higher than either 59.3 Hz or 59.1 Hz. The requirement is that by the first step (either 59.1 Hz or 59.3 Hz) the target amount of load should be dropped. In any event, the required amount of load available to be restored must be available from the highest block, e.g. the 59.3 Hz block in Plan 59.3 or the 59.1 Hz block in Plan 59.1.

Transient stability studies were conducted to confirm the performance of the UFLS plans now used by member systems, and Plans 59.3 and 59.1 discussed above. The plans were evaluated under two power flow cases which were considered to be representative of realistic boundary conditions in the WECC. One power flow case was based on August 10, 1996 operating conditions which represent heavy north-to-south flows on the Pacific Interties (i.e. heavy imports into the Southern region). Two outages were simulated to compare the UFLS plans under different resource losses. The first outage (10% Outage) consisted of loss of the COI path followed by operation of the NE/SE separation scheme and other remedial measures (e.g. generator tripping in the NW); all of which result in the controlled formation of the Northern and Southern Islands. With loss of the COI and TOT2 paths, the Southern island suffered a resource deficiency of about 5,700 MW, or 10% (i.e. [Gen + Import loss]/[Total Gen + Import]). The second outage (27% Outage) is identical to the first plus an additional 9,000 MW loss of generation resulting in a total loss of resources of about 14,800 MW, or 27%.

The other power flow case was based on December 14, 1994 operating conditions which represent heavy south-to-north flows on the Pacific Interties (i.e. heavy imports into the Northern region). The outage was similar but not identical to the December 14, 1994 disturbance which resulted in the creation of Northern and Southern Islands. Rather than sequence the tie-line breaker operations and generator trips, everything was tripped at t = 1.0 second. This simultaneous action represents a more severe condition than the sequential loss of elements which occurred on December 14. This outage (29% Outage) represents a total loss of resources of about 9,000 MW, or 29%.

Based on the overall study results, both Plan 59.3 and Plan 59.1 provide satisfactory performance in terms of frequency dip and the rate of frequency restoration compared to the UFLS plans now in service. Plan 59.3 does appear to provide marginally better performance than Plan 59.1 and the UFLS plans now used in service. For example, Plan 59.3 results in lower frequency dips and faster frequency restoration, though at higher amounts of load shedding as shown in the stability results tables section (XVI. Tables). From a technical point of view, both Plan 59.3 and Plan 59.1 meet the study performance objectives of arresting the frequency and restoring the frequency within 59.5 and 60.5 Hz. Also, there does not appear to be a difference from an economic perspective, since either Plan 59.3 or Plan 59.1 would require all participating members to revise block sizes and reset relays. A parallel initiative is currently assessing the benefits of direct load tripping (DLT) in the southern island formed in response to an outage of the California-Oregon AC Interconnection (COI). A key result from the DLT effort is that the frequency excursion bottoms out at around 59.1 Hz absent the UFLS program. Clearly, if the UFLS Plan 59.3 and the DLT program were implemented at the same time, the initial frequency setting of the UFLS program would cause an unnecessary tripping of load for COI outages. In the interest of making these two important programs compatible, Plan 59.1 should be adopted as the Council's UFLS plan.

Recommendation 2A: The Council should adopt the 59.1 Hz Plan as a minimum standard.

Load Shedding Block	% of customer load dropped	pickup (Hz)	tripping time
1	5.3	59.1	-
2	5.9	58.9	-
3	6.5	58.7	-
4	6.7	58.5	-
5	6.7	58.3	-
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

Though the studies assumed a combined 12 cycle relay and breaker operating time, some member systems currently have a minimum operating time of 14 cycles due to equipment specifications. A sensitivity study showed imperceptible difference between changes in relay and breaker operating times shedding as shown in the stability results tables section for Modified Option #2 (XVI. Tables). Therefore, a system average total tripping (relay & breaker) time of no more than 14 cycles is being recommended.

Recommendation 2B: The system average total tripping (relay & breaker) time should be no more than 14 cycles at the indicated frequency set points.

The objective of the coordinated UFLS program is to have a program that functions properly independent of season, day of the week, time of day, or load level. Hence, intermittent load should not be an integral part of the coordinated program. Intermittent load in the context of this discussion refers to load whose status may be highly variable or unpredictable. Some examples are pumping load that may depend on water conditions or operate only during restricted time periods, or pumped storage facilities. This type of load may be the easiest to interrupt or have the lowest service priority, but unless the UFLS program is modified continuously to reflect the operating status of this intermittent load the UFLS program will not work properly. From a different perspective, not making this intermittent load an integral part of the UFLS program gives the dispatcher additional tools to easily balance load and generation or permit rapid restoration of customer load following the disturbance. Relying on intermittent load to meet regional load shedding requirements undermines the integrity of the entire UFLS program.

Recommendation 2C: Intermittent load shall not be used unless monitoring is in place to allow changes in real time to accommodate the availability of the intermittent load and ensure the load shedding requirements of the Coordinated Plan are met.

The following four recommendations were formulated by the Underfrequency Program Implementation Task Force to provide additional guidance in implementing the UFLS program as stated in Recommendation 2A.

Recommendation 2D: Additional load can be tripped at frequencies higher than 59.1 Hz provided it does not violate the MORC or adversely impact neighboring systems. Frequency overshoot must be adequately addressed.

Recommendation 2E: It is not permissible to start shedding load at frequencies lower than 59.1 Hz or to trip less load than called for by the Coordinated Plan.

Recommendation 2F: Additional frequency set points can be used provided the cumulative total load shedding amounts meet the requirements of the Coordinated Plan for each of the Plan's frequency set points.

Recommendation 2G: Where programs differ from the Coordinated Plan, member systems are responsible for conducting studies to verify compliance with the Plan. These studies will be reviewed by the Underfrequency Implementation Task Force.

VIII. Load Restoration

Policy 5 in the NERC Operating Manual contains the following statements:

"Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the system is restored."

"Automatic restoration of load may be used where feasible to minimize restoration time. Automatic restoration should be coordinated with neighboring systems, coordinated areas, and Regions. Automatic restoration should not aggravate system frequency excursions, overload tie lines, or burden any system in the Interconnection."

Article B2 of the NERC Performance Standard Training Document contained in the NERC Operating Manual contains the following statement:

"During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variations. However, an area is expected to activate operating reserve to recover ACE within ten minutes."

Section 5.D.4 of the Minimum Operating Reliability Criteria (MORC, March 1997) states the following:

"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 be accomplished through a comprehensive program established in thorough coordination with neighboring systems and designed to avoid the possibility of recreating underfrequency, overloading ties, or burdening neighboring systems. Relays installed to restore load automatically should be set with varying and relatively long time delays, except in those cases where automatic load restoration is designed to protect against frequency overshoot."

A 1% generation/load imbalance causes a steady state frequency deviation of 0.4 Hz as shown in the tables section (XVII. Tables). The off-nominal frequency program is designed to have a post-disturbance frequency within the range of 59.5-60.5 Hz because frequencies outside this range are within the "time to damage" characteristics of some generating units and are protected by time delay relays. MORC requires all control areas to continually maintain minimum spinning and operating reserves, available in ten minutes, to cover their largest resource loss or 5% of their loads served by hydro generation and 7% of their load requirements met with steam generation. MORC is correct in requiring relatively long time delays before automatic restoration is attempted. The Task Force suggests that automatic load restoration occur no sooner than thirty minutes after 60 Hz (μ 0.05 Hz) is restored, and no more than 2% every five minutes. Historically, islands are able to reestablish tie lines within this time period and additional generation is available. At no time should automatic restoration of load interfere with the efforts to reestablish interconnections and otherwise restore the system.

The minimum time delay of 30 minutes after the frequency has been restored to and stabilized at 60 Hz is expected to be sufficient enough to reestablish key interties prior to bringing hydro systems back on line, and thus allowing load to be automatically restored in a timely fashion.

This is important from a system perspective; MORC suggests that the fastest way to restore the overall system is to reestablish the interconnections before load restoration begins. The local hydro areas must interface with the neighboring thermal areas. In addition, the relays that restore load automatically monitor only the frequency, not the status of system conditions. Hence, any automatic load restoration plan should be implemented using conservative assumptions as opposed to best case or even normal assumptions.

Recommendation 3A: All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WECC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration.

Recommendation 3B: To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational.

IX. Tie Line Tripping

Section 6.C.6 of MORC states the following:

“ 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.”

Policy 5 in the NERC Operating Manual contains the following statements:

“When an operating emergency occurs, a prime consideration shall be to maintain parallel operation throughout the Interconnection. This will permit rendering maximum assistance to the system(s) in trouble.”

“Because the facilities of each system may be vital to the secure operation of the Interconnection, systems and control areas shall make every effort to remain connected to the Interconnection. However, if a system or control area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system.”

The proposed UFLS program is designed to arrest the frequency decline at 57.9 Hz. If the frequency declines below 57.9 Hz, the “time to damage” of some generating units is within 7.5 seconds and “intolerable system conditions exist.” If a system decides to implement automatic tripping of tie lines due to underfrequency, then the set point should be no higher than 57.9 Hz, with a suggested time delay of one second to allow for a transient swing.

Tripping tie lines is not without risk. If the interconnection is supporting the individual system, then tripping the tie lines will almost certainly mean total collapse for that individual system. If the individual system is supporting the interconnection, then tripping the tie lines will put the interconnection at greater risk. Unless sophisticated relaying is implemented (perhaps looking at the direction of power flow), there is no way for an individual relay to discriminate between the two conditions. However, the ultimate decision rests with the individual system. From an overall system perspective, the preferred option is to not trip transmission lines due to underfrequency.

Recommendation 4: Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one second time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

X. Generators

Policy 4, Subsection D, Guide 1.6. of the NERC Operating Guides states the following:

"**Underfrequency relays.** Underfrequency load shedding relays should be coordinated with the generating plant off-frequency relays to assure preservation of system stability and integrity. (II.D.r.1.6.)"

Policy 5, Subsection D, Guide 2. of the NERC Operating Guides states the following:

"**Generator shutdown**. If abnormal levels of frequency or voltage resulting from an area disturbance make it unsafe to operate the generators or their support equipment in parallel with the system, their separation or shutdown should be accomplished in a manner to minimize the time required to re-parallel and restore the system to normal. (III.F.r.1.)

2.1 **Separating generators with local load.** If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliaries. (V.D.r.4.)"

Policy 5, Subsection D, Guide 5. of the NERC Operating Guides states the following:

"**Generator protection at high and low frequency**. Protection systems should be considered for automatically separating the generators from the system at predetermined high and low frequencies. (III.A.r.3.1.)"

One of the fundamental objectives is to implement an off-nominal frequency program that coordinates with the requirements of the generators. A corollary requirement is that the generators in turn coordinate with the off-nominal frequency program. The off-nominal frequency program was designed to coordinate with the most conservative 5% loss of life criteria imposed by any manufacturer. The generators, in turn, must not individually or unilaterally set their off normal frequency protection to be any tighter than that permitted by the 5% loss of life criteria specified by the manufacturers and assumed in the coordinated off-nominal frequency program.

Some units on the distribution system have much tighter frequency limitations to prevent them from being isolated on a radial feed with dramatic frequency swings. This is a legitimate requirement. From a system perspective, additional load must be tripped on a one-for-one basis to not degrade overall system integrity.

Recommendation 5A: Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames:

Underfrequency Limit	***Overfrequency Limit***	***Minimum Time***
60.0-59.5 Hz	***60.0-60.5 Hz***	***N/A (continuous operating range)***
59.4-58.5 Hz	***60.6-61.5 Hz***	***3 minutes***
58.4-57.9 Hz	***61.6-61.7 Hz***	***30 seconds***
57.8-57.4 Hz		***7.5 seconds***
57.3-56.9 Hz		***45 cycles***
56.8-56.5 Hz		***7.2 cycles***
less than 56.4 Hz	***greater than 61.7 Hz***	***instantaneous trip***

Recommendation 5B: Systems that have generators that do not meet the requirements in Recommendation 5A must automatically trip load (in addition to that required in Recommendation 2A) to match the anticipated generation loss and at comparable frequency levels.

Recommendation 5C: All systems that own/operate generating facilities shall provide data to WECC regarding the off-nominal frequency protection settings of their units. Any changes in settings shall also be reported.

XI. Relays

Article 5.2 of MORC contains the following statement:

"All automatic underfrequency load shedding comprising a coordinated load shedding program shall be accomplished by the use of solid-state underfrequency relays. Electro-mechanical relays are not to be used as part of any coordinated load shedding program."

The above statement has been in MORC since 1974. This requirement is based on solid technical reasons and is not in dispute, hence the rationale will not be presented here. However, electro-mechanical relays are still in use and should be eliminated as part of the total review of the UFLS program.

The Relay Work Group would like to give visibility to their long standing recommendation that only the definite time characteristic of the underfrequency relay be used. An inverse time characteristic or rate of frequency characteristic is not to be used.

The Relay Work Group recommends that underfrequency relays be enabled for voltages as low as 80% of nominal, unless local conditions dictate otherwise. This recommendation was approved by the Technical Operations Subcommittee.

CMOPS recommends that only loads tripped by underfrequency relays should be considered when determining compliance with the UFLS plan.

TOS and CMOPS recommend that only solid state frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz .

TOS recommends that electromechanical frequency relays may be used for either load or generation only if their trip settings are outside the range of 57.9-61.0 Hz.

Recommendation 6A: Only solid state and/or microprocessor underfrequency relays shall be used as part of the Coordinated Plan. Only load tripped by solid state and/or microprocessor underfrequency relays will be considered when determining compliance with the Coordinated Plan.

Recommendation 6B: Only solid state and/or microprocessor frequency relays should be used on generators to provide off-nominal frequency protection in the range of 57.9-61.0 Hz.

Recommendation 6C: All frequency relays shall use the definite time characteristic and should not be disabled for voltages 80% of nominal or higher but can be disabled for voltages below 80% of nominal (at the discretion of the setting entity).

Recommendation 6D: Electro-mechanical frequency relays can be used only for settings outside the 57.9-61.0 Hz range

XII. Overvoltage protection

When loads are shed suddenly during an underfrequency event, shunt capacitors remaining in service may cause serious overvoltages. Because of this condition, shunt capacitors on the transmission system should either have automatic overvoltage protection or be tripped by underfrequency relays. If the overvoltages are severe enough, they should be tripped as an integral part of the off-nominal frequency program.

Recommendation 7: To protect against overvoltages following an underfrequency load shedding event, systems shall implement automatic measures to maintain voltages within acceptable limits.

XIII. Direct Load Tripping

There may be specific disturbances for which load needs to be tripped faster than afforded by an UFLS program to adequately arrest frequency and avoid cascading. This may be required either for regional or local needs. The program should allow such actions as long as it enhances and does not compromise the overall uniform program.

Direct load tripping can be accomplished by sending trip signals to shed load based on pre-programmed logic or by using UFLS relays with frequency set points above 59.1 Hz. If a direct load tripping scheme employs UFLS relays, the load scheduled to be shed at the designated high frequency set points can be counted toward the 59.1 Hz UFLS plan requirement.

Recommendation 8: Direct load tripping is allowed if it complements the Coordinated Plan (see Recommendation 2G).

XIV. WECC Reliability Coordinators

CMOPS recommends that each Reliability Coordinator develop comprehensive and detailed guides for the restoration of load following a load shedding event. While MORC gives clear guidelines in this regard, nevertheless the experience with the disturbances of July and August 1996 indicate that more coordination and clarification is needed.

Recommendation 9: Each of the Reliability Coordinators shall develop comprehensive and detailed guides for the restoration of load following a load shedding event.

XV. Relationship to Other Council Initiatives

A separate effort is underway within the Council by the Controlled Islanding ad hoc Task Force to determine if the formation of islands can be "controlled." The recommendations contained in this report are independent of the upcoming recommendations from the Controlled Islanding ad hoc Task Force. If the formation of islands can be controlled, then there will still be a uniform off-nominal frequency program within that island. If the islands are not controlled or do not form as intended, there will be a uniform off-nominal frequency program in whatever islands form. If no islands are formed, then there will be a uniform program throughout all of the Council.

As previously discussed, another group within the Council is evaluating whether there should be direct load tripping by the users of COI for a COI outage. If sufficient direct load tripping is recommended, then the generation/load imbalance in the southern island will not result in frequency deviations below 59.1 Hz and underfrequency load shedding will not occur if Plan 59.1 is adopted. Thus, the recommended UFLS program specified as Recommendation 2A is not affected. If direct load tripping is not implemented, then there will be a uniform program (Plan 59.1 or Plan 59.3) for the entire southern island. For contingencies other than COI, there will be a uniform program throughout the Council.

XVI. Tables

The tables on the following pages reflect the UFLS assessments and stability results.

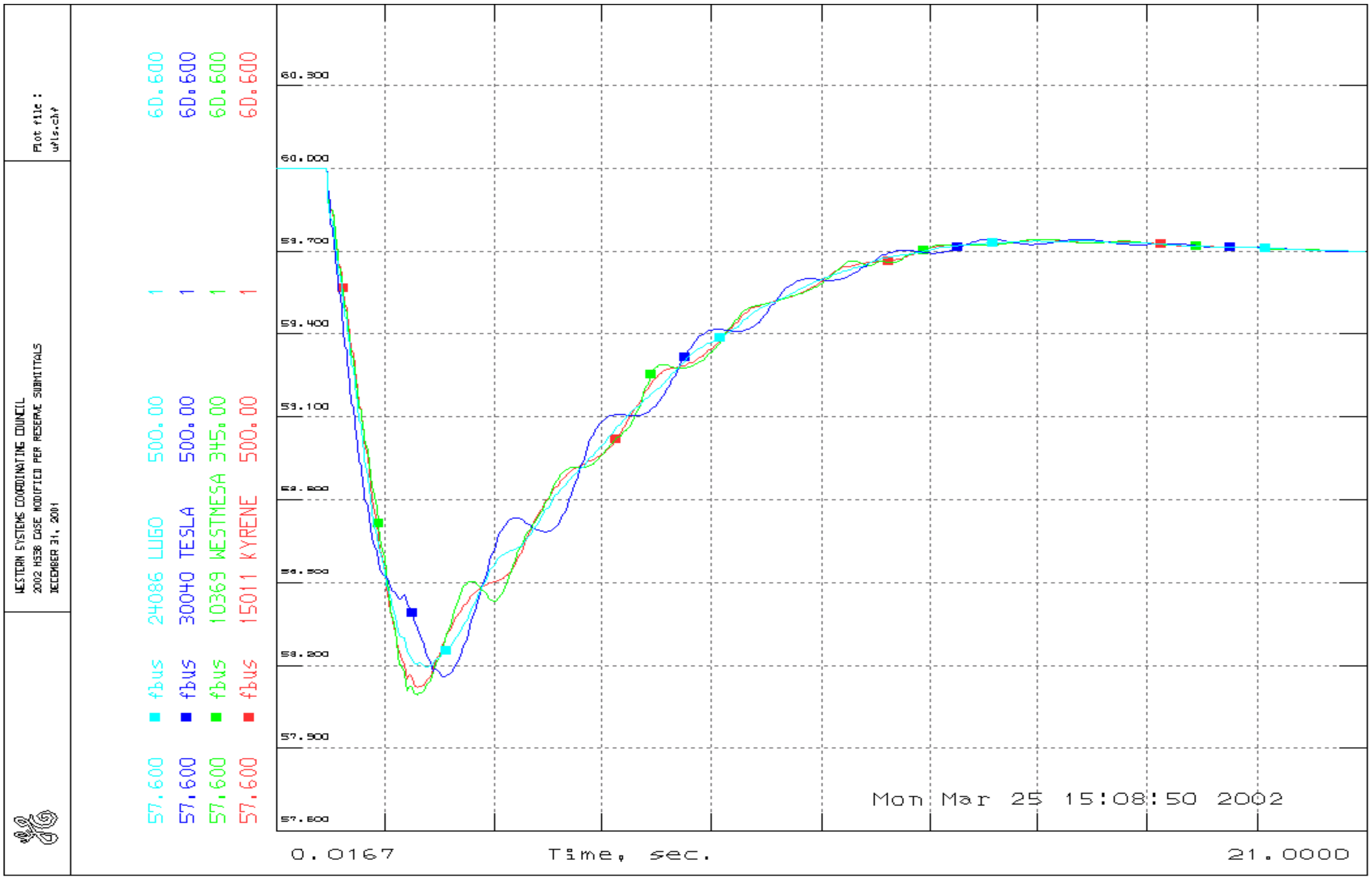
XVII. Attachments

The Attachments on the following pages include information referred to in the Report.

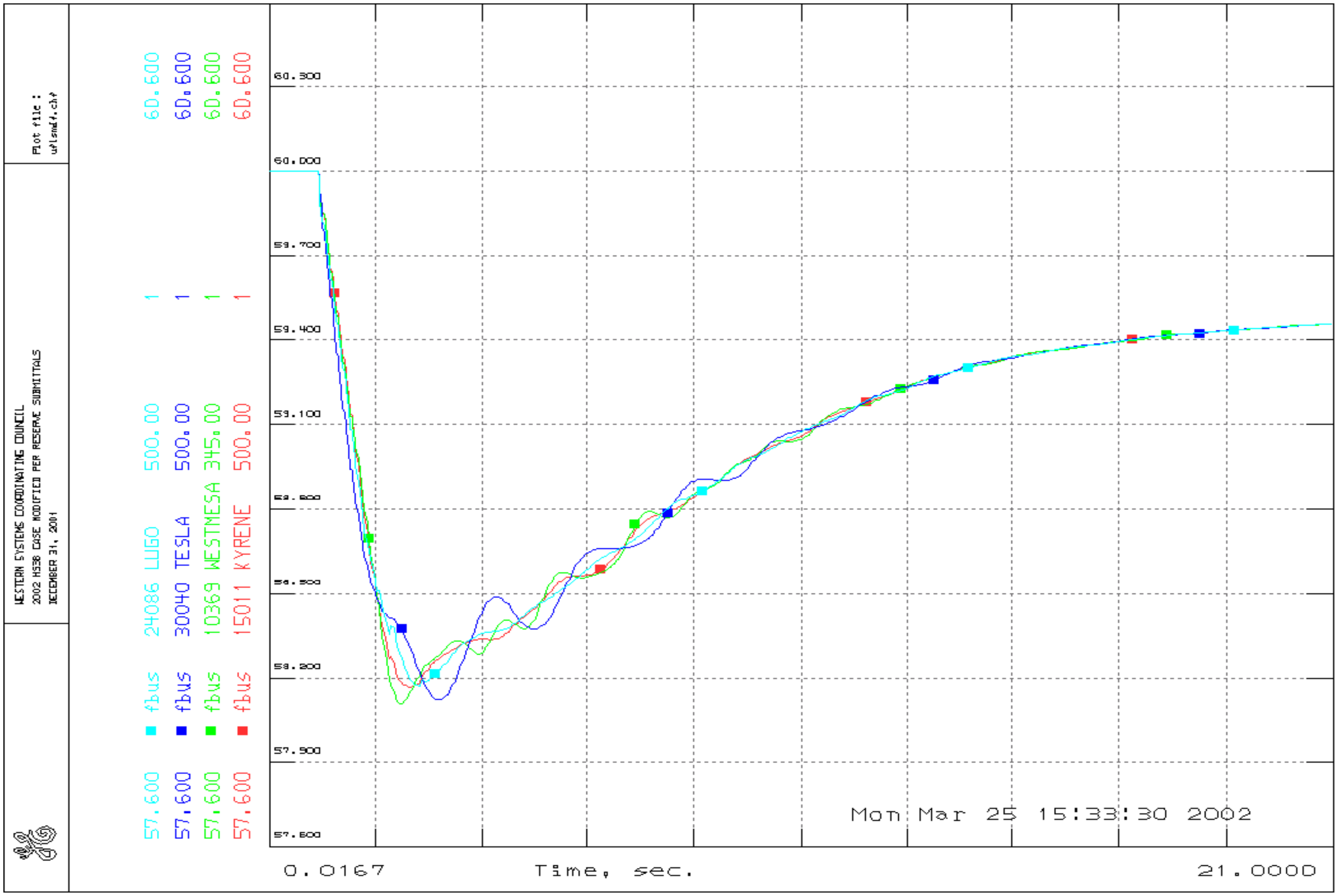
Appendix 2

Frequency Plots for the Southern Import Scenario

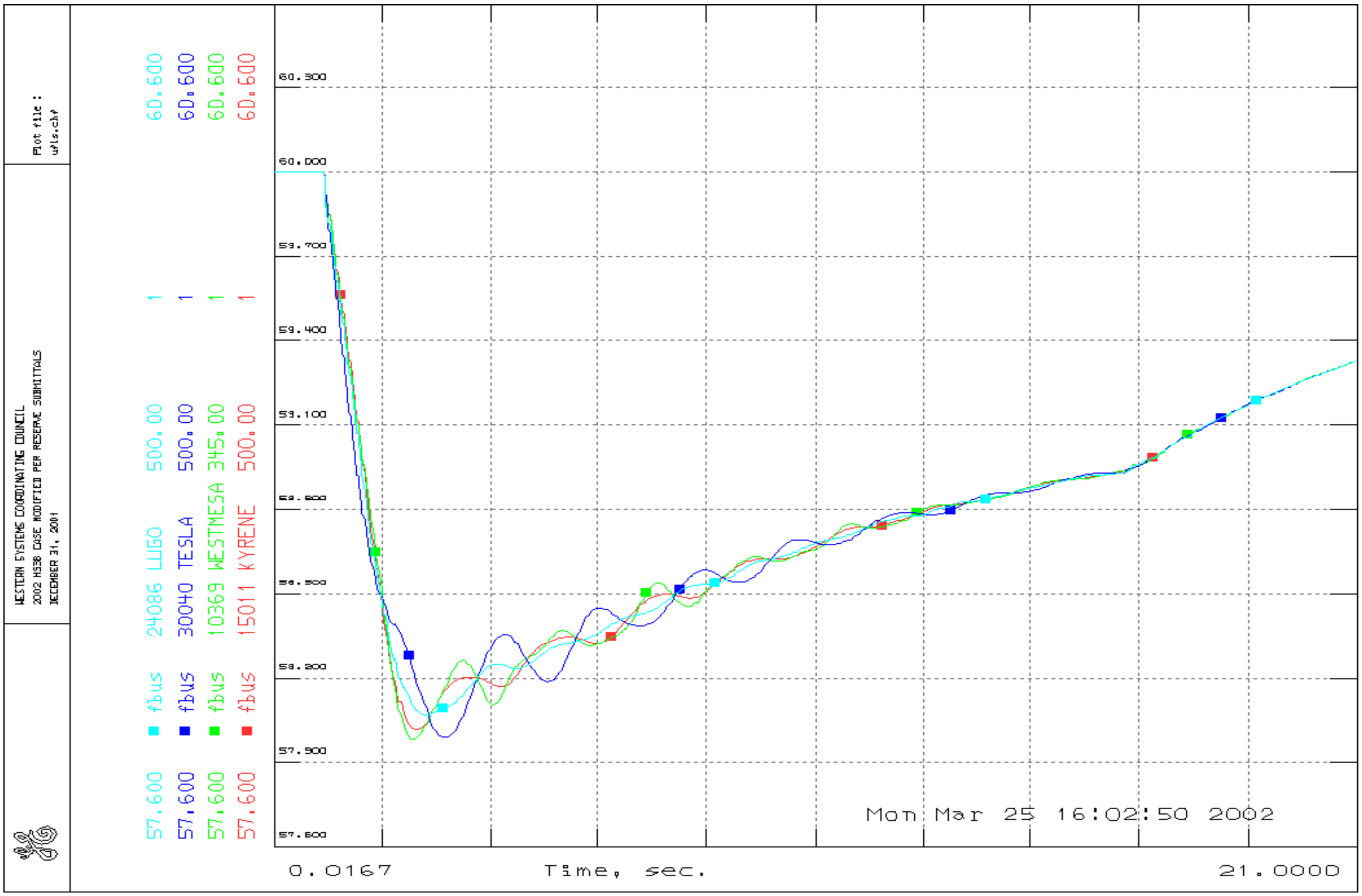
PLOT 1: GENERIC DATA FOR EXISTING PLAN



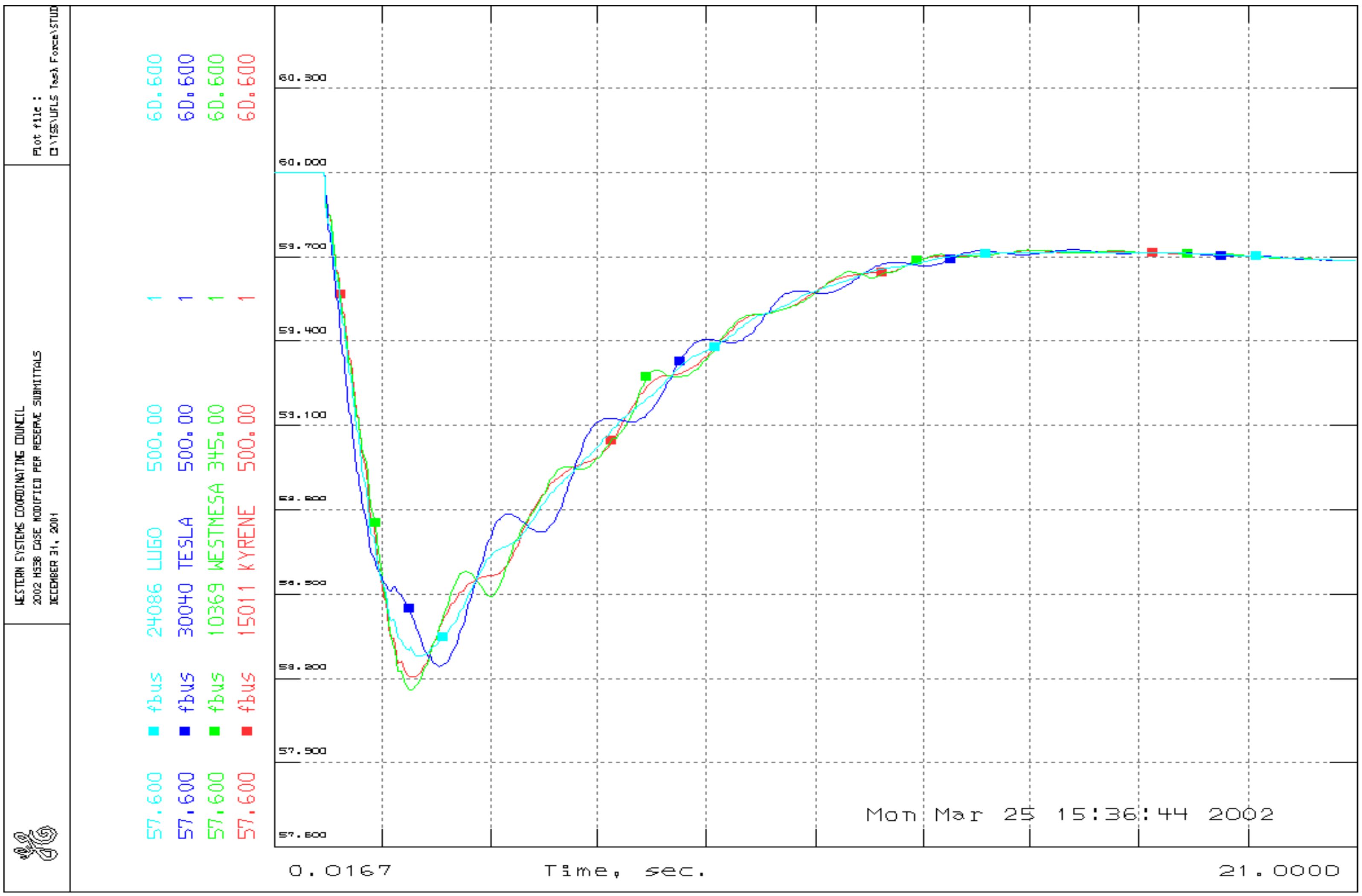
<u>PLOT 2: USING EXISTING UFLS DATA IN MDF</u>



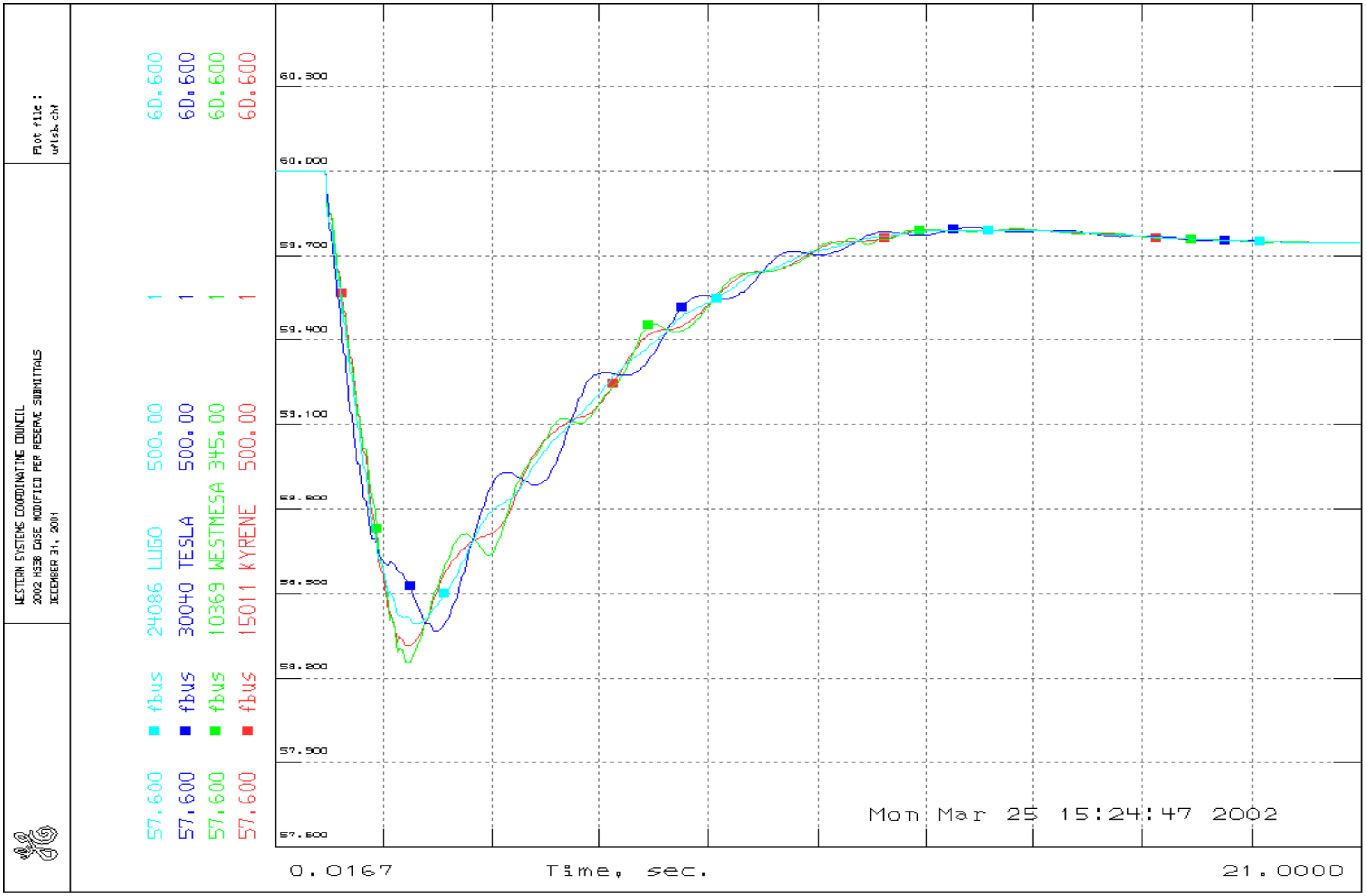
PLOT 3: GENERIC DATA FOR EXISTING PLAN USING GGOV1 MODEL AT RESPONSIVE UNITS



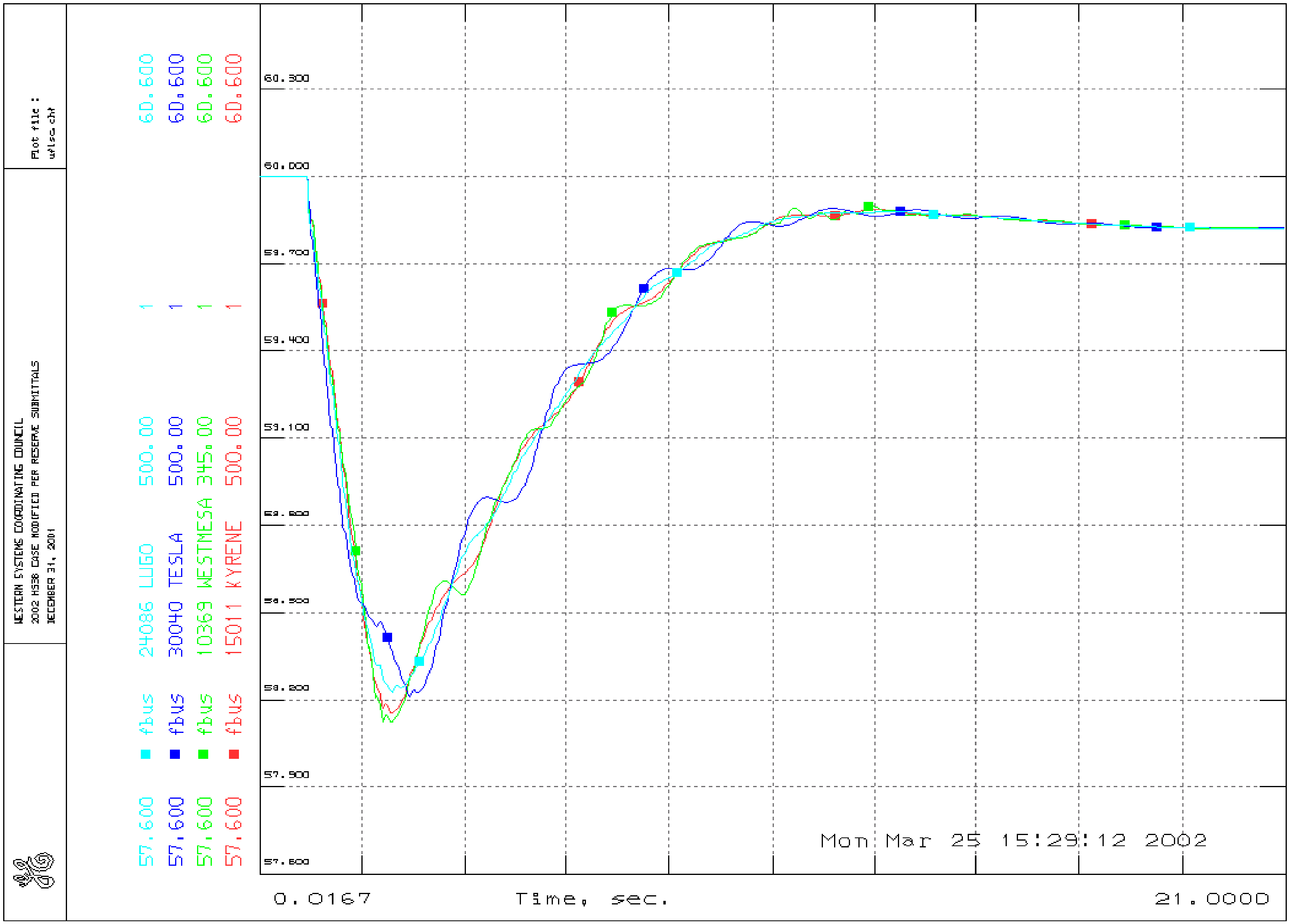
PLOT 4: INCREASE FREQUENCY TRIP POINTS BY .1 Hz



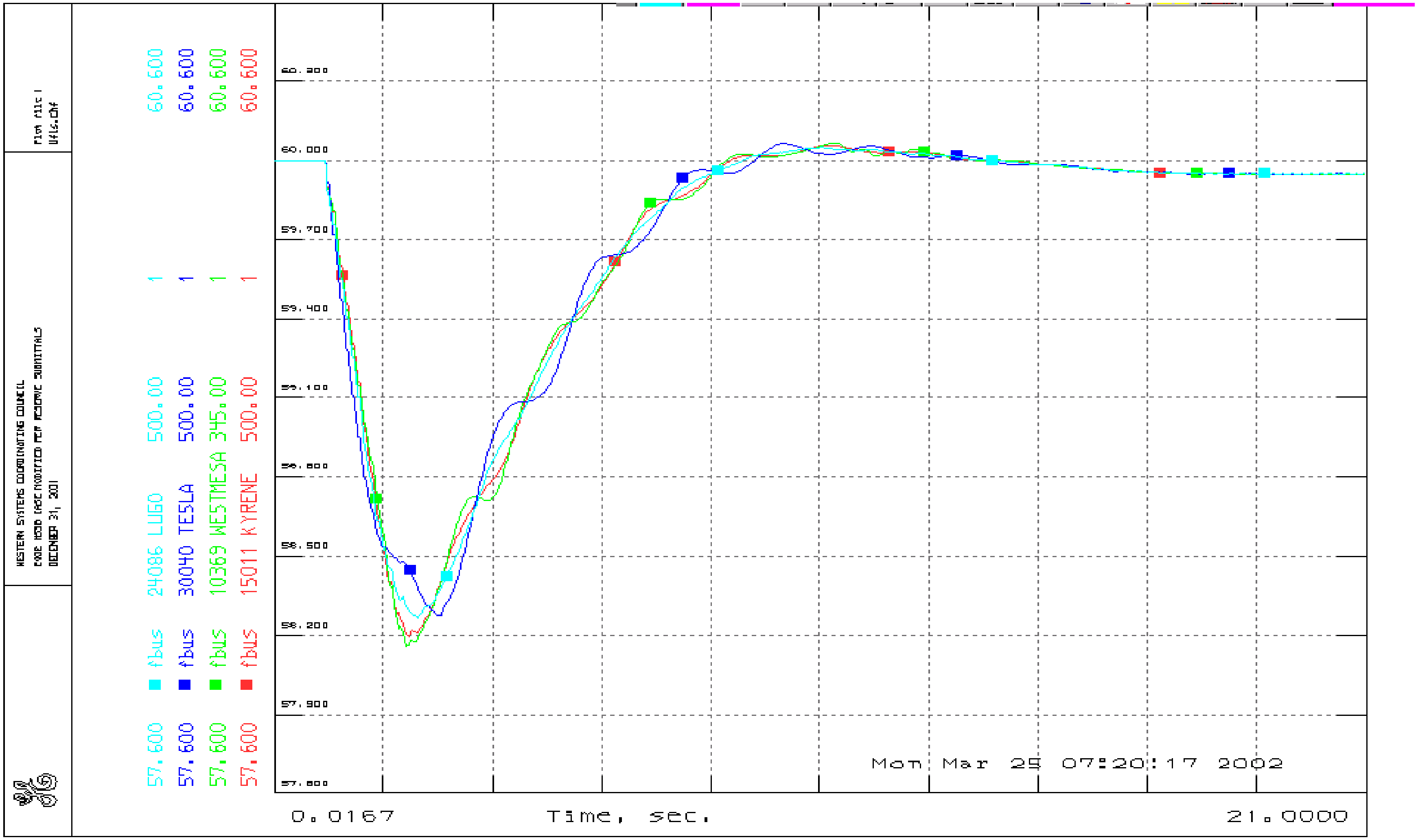
PLOT 5: INCREASE FREQUENCY TRIP POINTS BY .2 Hz



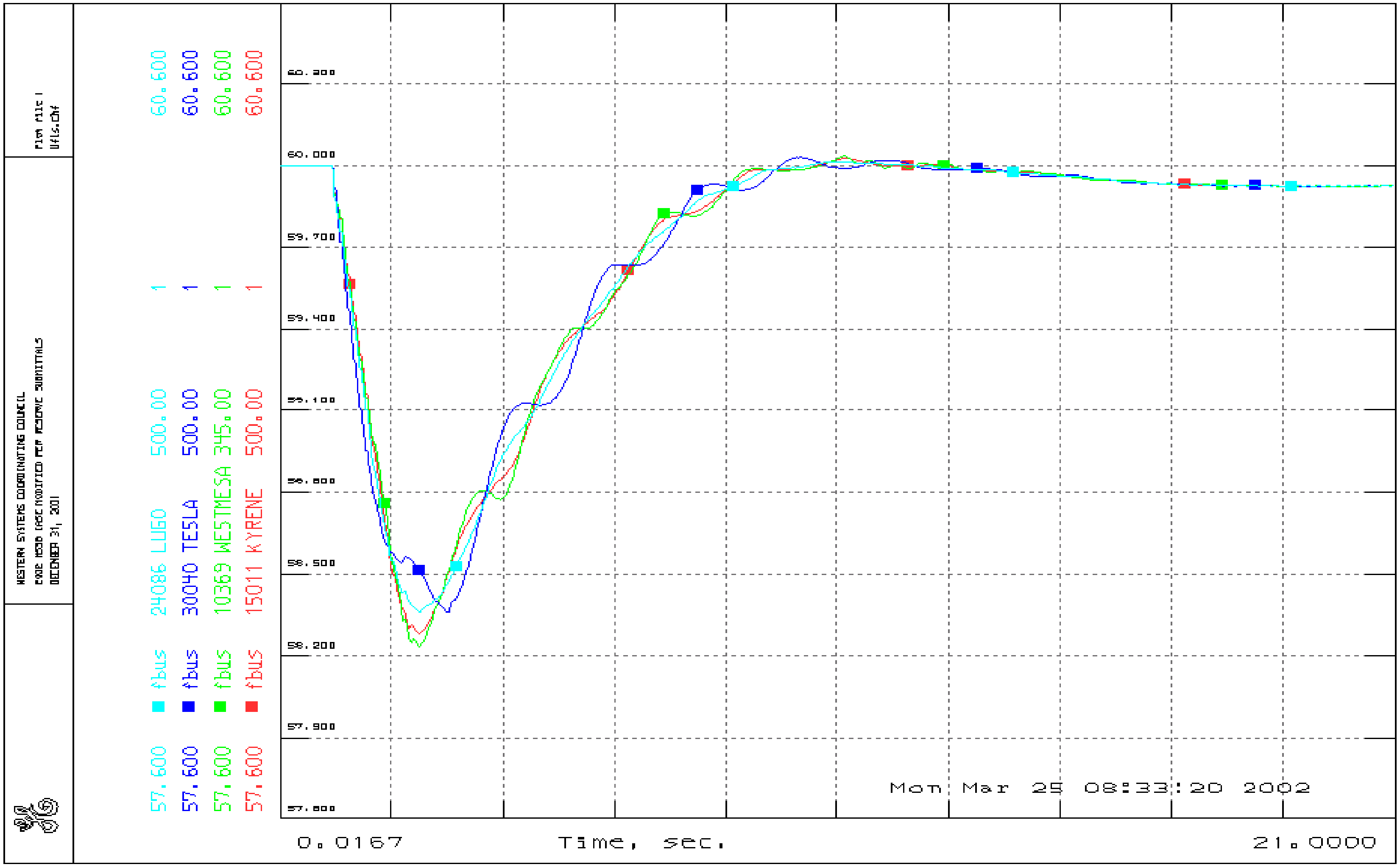
PLOT 6: INCREASE LOAD SHED AT EACH FREQUENCY BY 0.5 %.



PLOT 7: INCREASE LOAD SHED AT EACH FREQUENCY BY 1.0 %.



PLOT 8: INCREASE FREQUENCY TRIP POINTS BY .1 Hz AND LOAD SHED AT EACH FREQUENCY BY 1.0 %

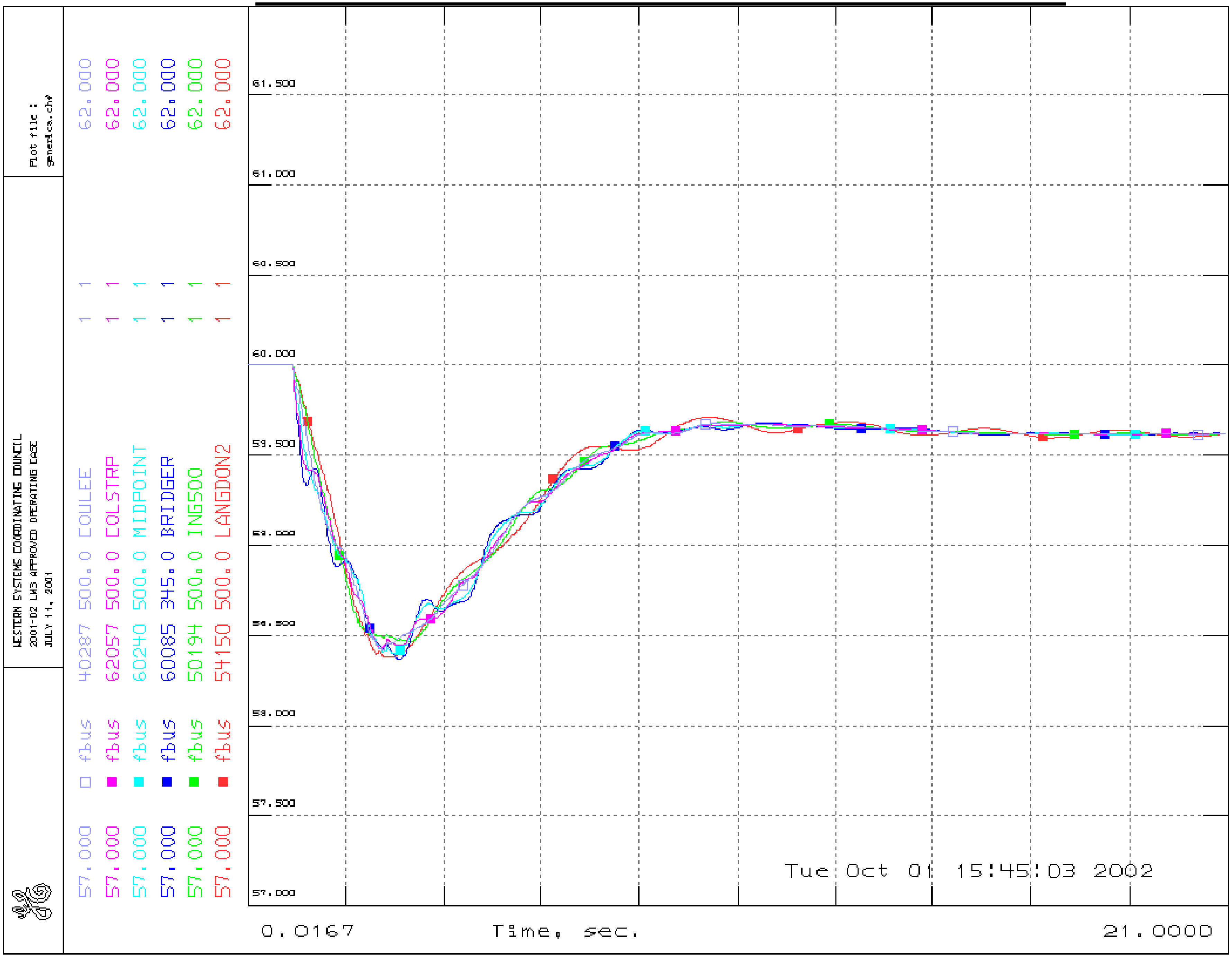


Appendix 3

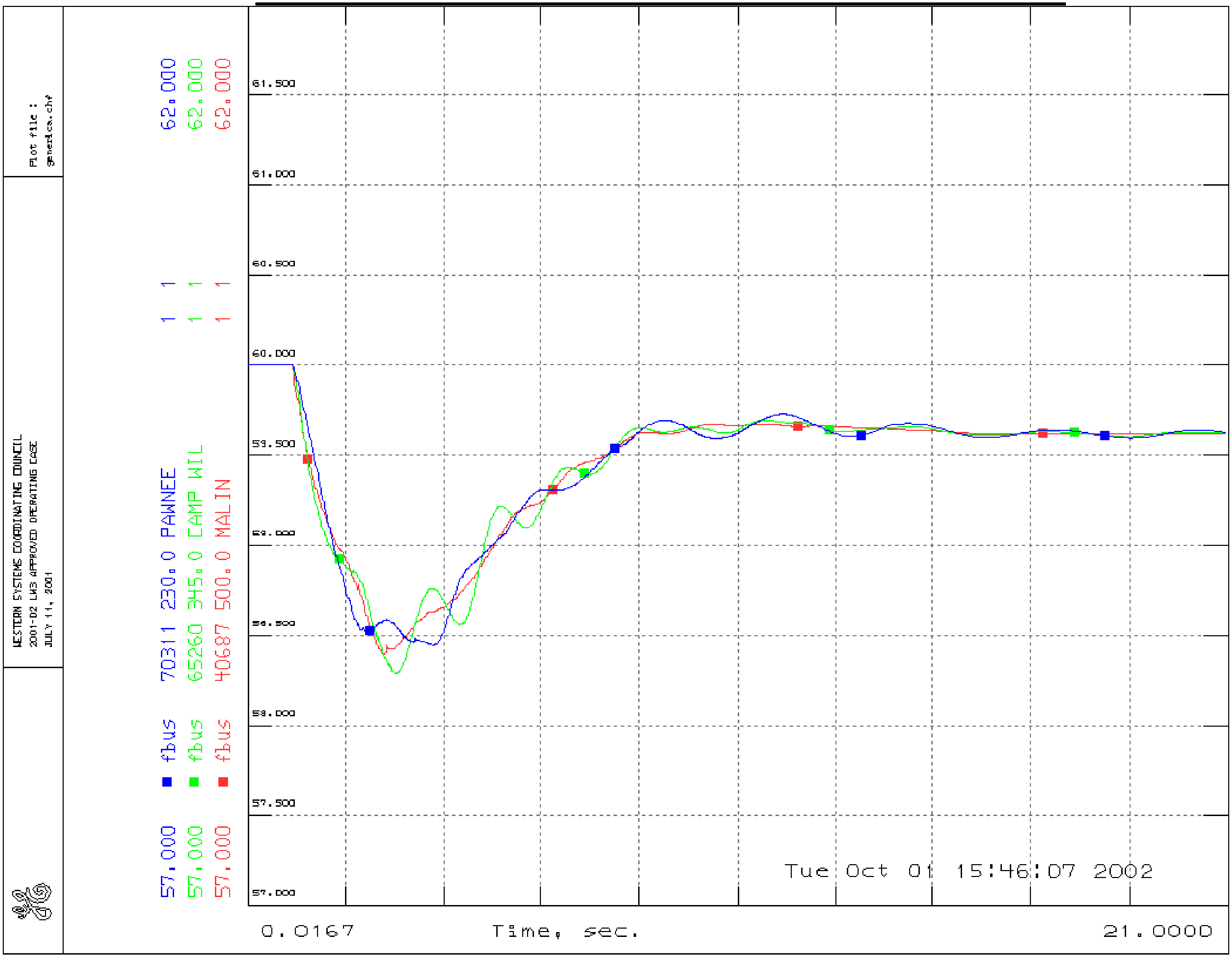
Frequency Plots for the Northern Import Scenario

Northern Import Scenario

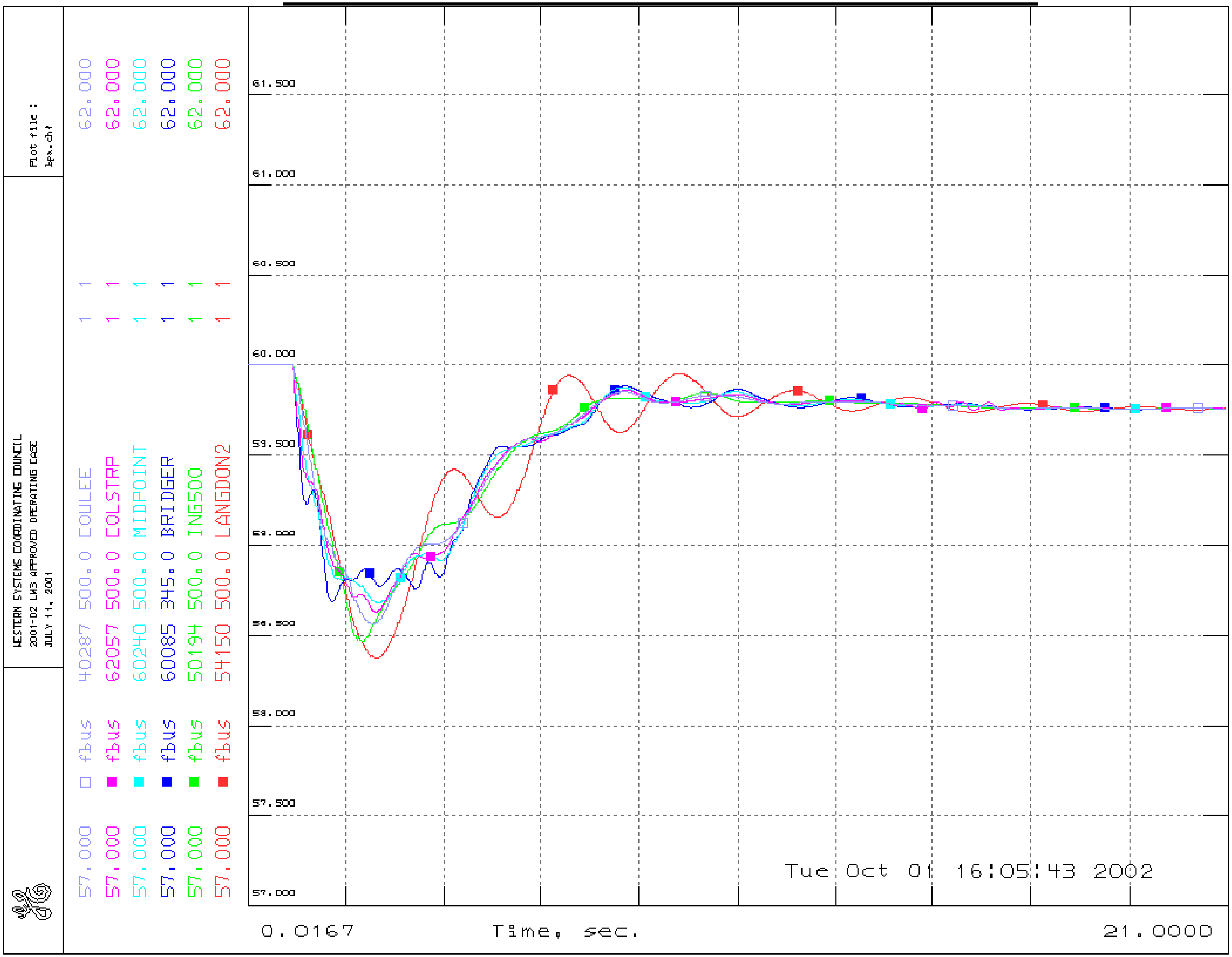
PLOT 1:GENERIC DATA FOR THE EXISTING PLAN



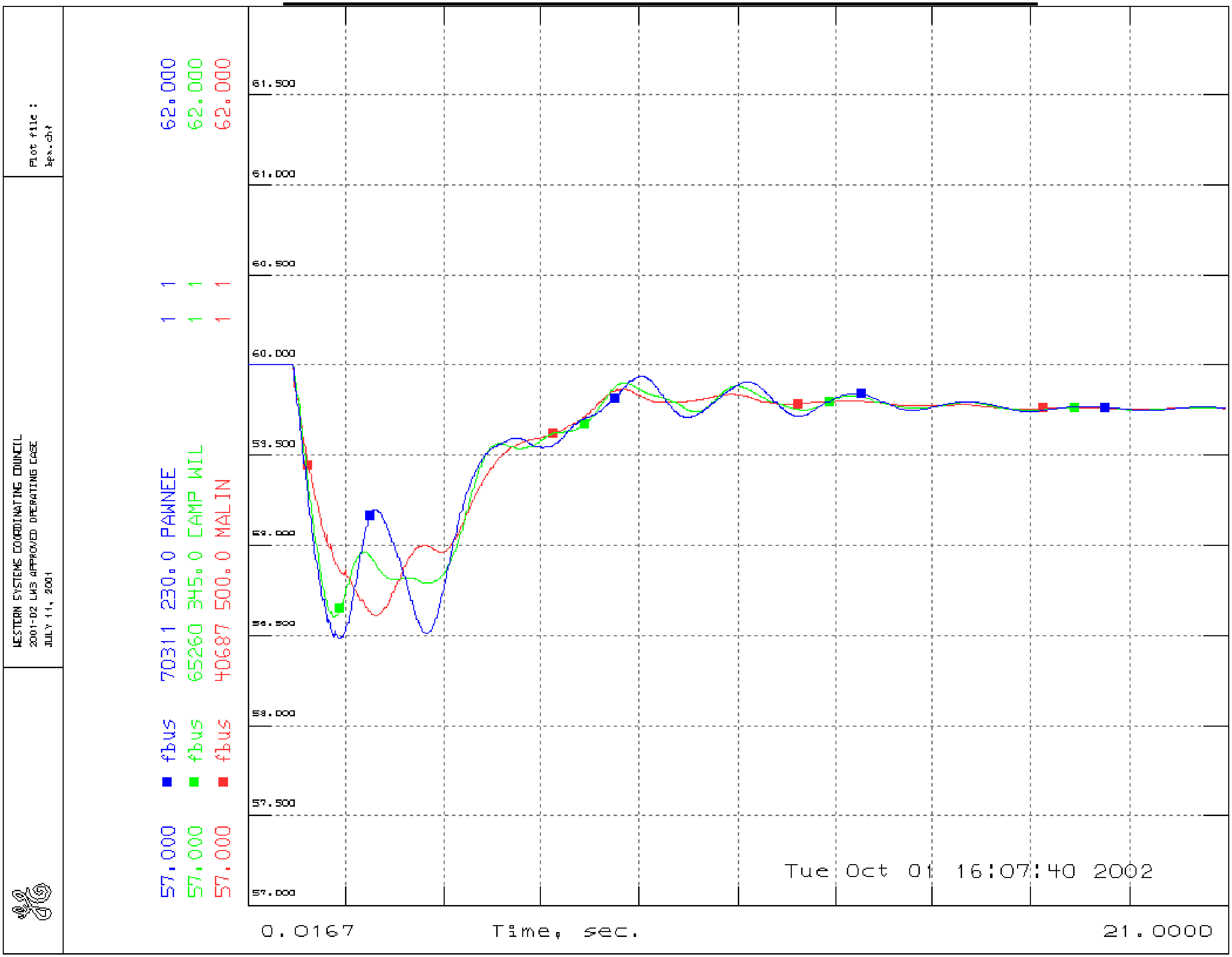
PLOT 2:GENERIC DATA FOR THE EXISTING PLAN



PLOT 3:NWPP MODIFIED OFF-NOMINAL PLAN



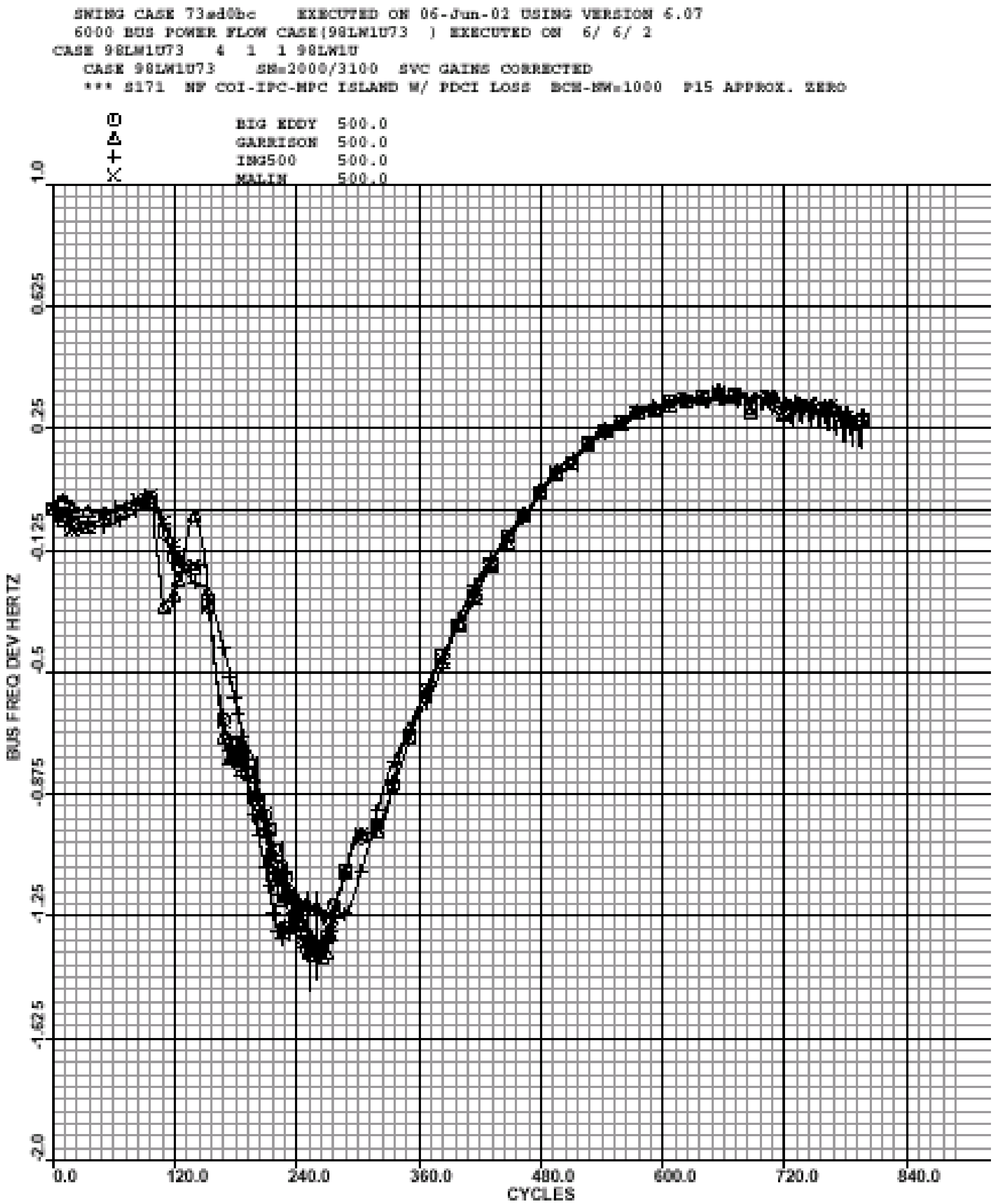
PLOT 4:NWPP MODIFIED OFF-NOMINAL PLAN



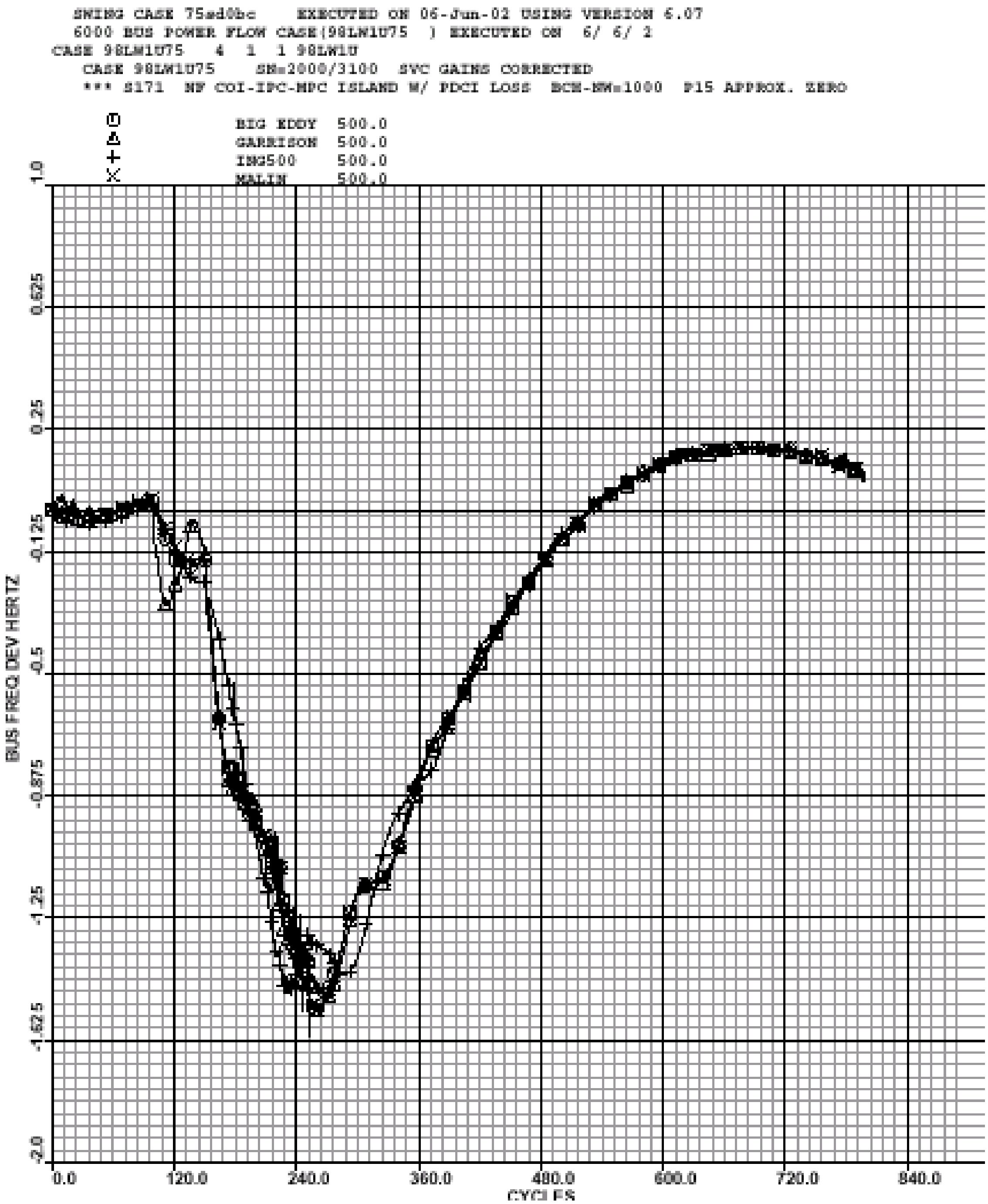
Appendix 4

Frequency Plots for BPA’s Evaluation of the Northern Import Scenario

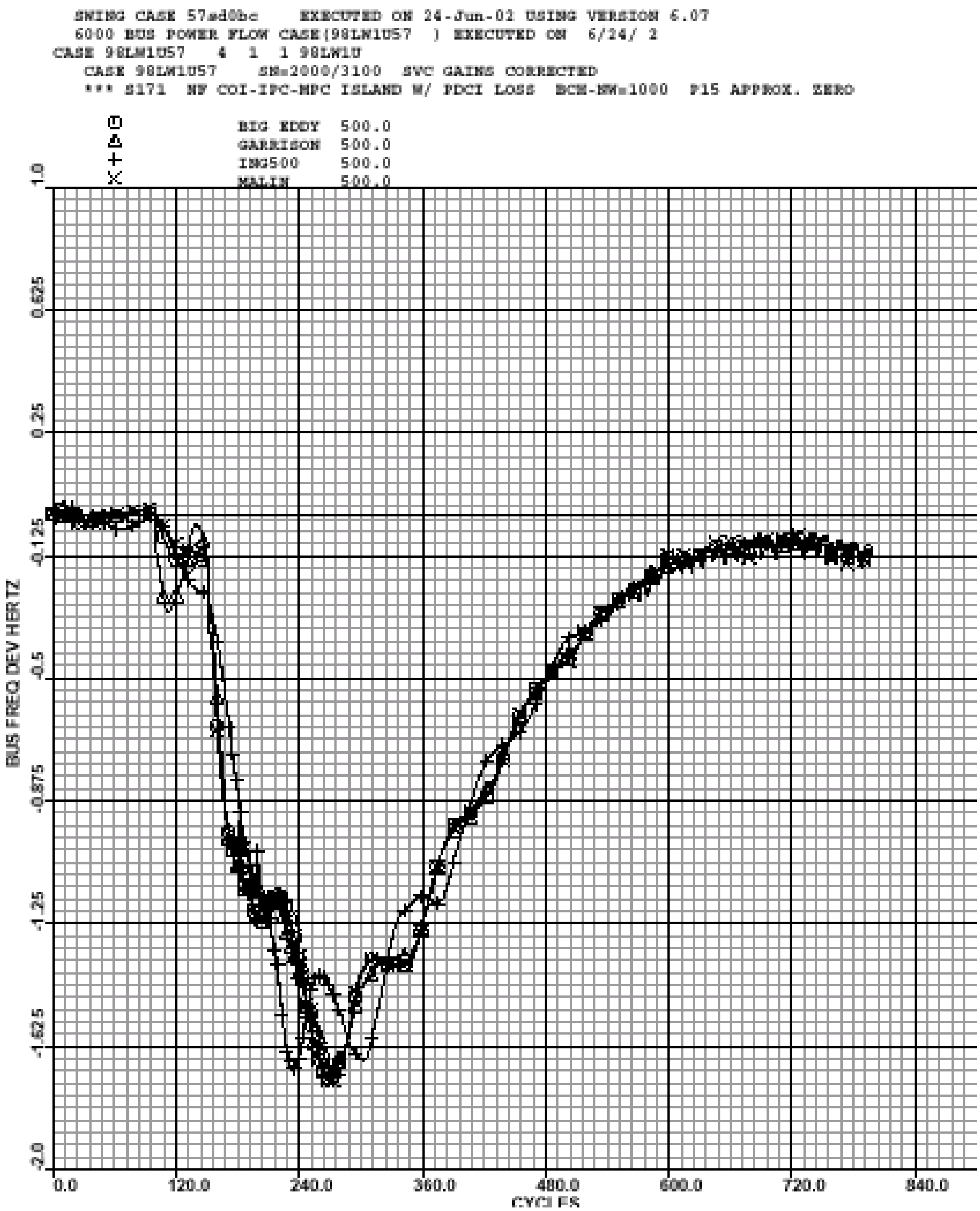
Plot 1: Case #57



Plot 2: Case #75



Plot 3: Case #57



Appendix 5

Off-Nominal Frequency Range Reduction Impact Assessment

Off-Nominal Frequency Range Reduction Impact Assessment

Impact on WECC Coordinated Off-Nominal Load Shedding Program

1. Summary

The existing WECC Underfrequency Load Shedding System (*UFLS*) is implemented in accordance with 1997 WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan and prevents violations of the "5% loss of turbine life" criteria for a maximum generation-load imbalance of 30-33%. *UFLS* consists of the *UFLS-A* and *UFLS-B* sub-systems. *UFLS-A* refers to the five fast acting blocks with different frequency settings and *UFLS-B* refers to the three anti-stalling blocks with different time delays.

This study analyzes the ability of existing *UFLS* to satisfy requirements imposed by some new gas units. The minimum permissible dynamic frequency for such units is 58.2 Hz. There are already fourteen of these units in the WECC area with a total capacity of 2520 MW. Twenty-four additional units will potentially be brought into operation in the WECC area in the near future.

This study assessment is based on simulations using an Equivalent System Analysis. This model provides satisfactory accuracy, being very flexible for variations of system parameters, lost generation and *UFLS* adjustment.

The following are the main conclusions of this study:

1. Existing *UFLS-A* provides $f_{settling}$=58.2 Hz on about 29.9% loss of generation. Even with this reduced $\Delta P_{Gen.Loss}$, system performance does not satisfy the "58.2 Hz " requirements, because frequency stalls at 58.2 Hz and stays at this level for about 15 sec. until initiation of *UFLS-B*.

2. The "58.2 Hz" requirements are satisfied for $\Delta P_{Gen.Loss} \leq 27.5$ %, if this $\Delta P_{Gen.Loss}$ is sufficient to trigger all five blocks of *UFLS-A*. If $\Delta P_{Gen.Loss} = 27.5$ %, frequency comes closely to 58.2 Hz, but does not stall and immediately rebounds, reaching 59.0 Hz for 15 sec.

3. The new frequency limitations are not ordinary for the existing *UFLS* design and require verification of system performance for moderate values of $\Delta P_{Gen.Loss}$. System frequency may stall in "blind spots" between settings of two blocks of

UFLS-A for 15 sec. until *UFLS-B* trips additional load[1]. This verification is not necessary with the "5% loss of life" limitations allowing 15-sec. operation in all possible "blind spots". The developed "*UFLS Can Handle*" table gives maximum durations of system operation with different off-nominal frequencies, which might be caused by $\Delta P_{Gen.Loss} \leq 27.5\ \%$ or $\Delta P_{Gen.Loss} \leq 30\ \%$ in the WECC system, equipped by existing *UFLS*. These durations represent abilities of particular UFLS system and should not be confused with any equipment limitations.

UFLS Can Handle Table

f(Hz)	Time (sec) for Pgen.loss≤27.5%	Time(sec) for Pgen.loss≤30%
59.5	<34.0	<37.5
59.0	<25.0	<30.0
58.8	<22.2	<27.0
58.6	<20.0	<24.0
58.4	<14.0	<21.5
58.3	<6.2	<20.0
58.2	0.0	<19.5
58.0	0.0	5.5
57.8	0.0	0.0

5. The existing UFLS system would handle $\Delta P_{Gen.Loss}=30\%$ (second column in the Table), if the manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust protection allowing immediate trip only at 57.8 Hz. The 2.5% *UFLS* capability reduction (from 30 to 27.5%) would occur if the manufacturers confirm[2] the time intervals only in the first column of this Table.

6. Reduction of the time intervals in the Table is also possible if actual requirements happen to be more severe. This study considers three different options for such a reduction. However all of those options require readjustments and most likely modifications and replacement of some of the frequency relays.

7. It is very likely that system performance with existing (or increased by 2.5%) *UFLS* may satisfy the manufacturers design specification for underfrequency operation. However, the correspondence between sizes of *UFLS* blocks, specified in the 1997 WSCC Plan, and their actual sizes becomes very critical. This was not so critical for the "5% loss if life" conditions.

---

[1] A value of $\Delta P_{Gen.Loss}$ belongs to a "blind spot" if this $\Delta P_{Gen.Loss}$ is barely covered by operation of some *UFLS-A* blocks, causing frequency stalling or its very slow restoration. The following block does not operate because of the insufficient frequency dip.

[2] There is no an available specification for turbine operation with frequencies above 58.2 Hz.

2. Background and Objectives

The "WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan" was developed and recommended for implementation throughout all of WECC in 1997. This plan specifies parameters of the load tripping blocks, which are able to prevent violations of the "5% loss of turbine life" criteria for a maximum generation-load imbalance of 30-33%:

Table 1.
WSCC Coordinated Off-Nominal Frequency Load Shedding Plan

UFLS-A - instantaneous *UFLS* (14 cycles)	*UFLS-B* - anti-stalling *UFLS*
Block 1 - 59.1 Hz, 4.75%,	Block 1 – 59.3 Hz, 2%, 15 sec.
Block 2 - 58.9 Hz – 5.25%,	Block 2 – 59.5 Hz, 1.5%, 30 sec.
Block 3 - 58.7 Hz – 5.75%,	Block 3 – 59.5 Hz, 1.78%, 60 sec.
Block 4 - 58.5 Hz – 6.0%,	
Block 5 - 58.3 Hz – 6.0 %	

.

Terms *UFLS-A* and *UFLS-B* are widely used in this report. *UFLS-A* refers to the five fast acting blocks with different frequency settings (left column in Table 1) and *UFLS-B* refers to the three anti-stalling blocks with different time delays (right column in Table 1).

There was a lot of confidence that the recommended *UFLS* is able to prevent damaging frequency dips and turbine protective trips. This confidence was based on two factors:

- The "5% loss of life" requirements were developed using the most restrictive limitations imposed by manufacturers.
- The Plan was developed with the assumption that the minimum permissible dynamic frequency is 57.9 Hz instead of 56.5 Hz, required by the "5% loss of life" criteria.

This study analyzes the ability of existing *UFLS* to satisfy the stricter requirement imposed by some new types of turbines. Accordingly to *UFLS* Task Force data, obtained from the manufacturers those turbines have an instantaneous trip requirement of 58.2 Hz. This limitation is caused by the possibility of high cycle resonance fatigue of compressor and turbine blades if rotating speeds coincide with blade natural frequencies.

There are already fourteen of those units in the WECC area with a total capacity of 2520 MW. Twenty-four additional units will potentially be brought in operation in the near future. Many of those units could be instantaneously tripped if an underfrequency disturbance event causes a frequency dip to 58.2 Hz. This may cause a further increase of system deficit beyond *UFLS* abilities with further frequency decrease along with other potentially negative consequences.

The objectives of this study are:

- Investigate the possibility of approaching 58.2 Hz on underfrequency disturbances, assumed as credible in the 1997 *UFLS* study (loss of generation of 30-33%), with the existing *UFLS* settings and block sizes.

- Determine the loss of generation that does not reduce frequency lower than 58.2 Hz with the existing *UFLS* settings and block sizes.

- Determine maximum possible durations of different frequency dips in the range between 60 and 58.2 Hz with the existing *UFLS* settings and block sizes.

- Determine methods of *UFLS* modification to provide satisfactory performance with the "58.2 Hz" limitations.

3. Equivalent System Analysis and Basic *UFLS* Performance Requirements

This study compares the abilities of *UFLS* to satisfy new and old frequency restrictions. The relative nature of the needed results makes them less dependant on model accuracies. Furthermore, for the purpose of this study, many system model details are unnecessary, as the system can be assumed stable and operating with the same frequency in all of its parts. These specifics were taken into account in the attempt to conduct the study with application of the simplified per unit model:

$$2H * \frac{\partial(\Delta f)}{\partial t} + K_F * \Delta f = \Delta P \qquad (1)$$

where loss of generation, and *UFLS* operation are simulated by changing ΔP, K_F, H:

$$\Delta P = \Delta P_{Gen.\ Loss} - \Delta P_{UFLS},$$
$$K_F = K_f * (1 - \Delta P_{UFLS}),$$
$$H = H_{Gen} / (1 - \Delta P_{Gen.\ Loss}) + H_{Load} / (1 - \Delta P_{UFLS})$$

A single flexible *UFLS* model controls the simple one-bus system frequency model, described by (1). This makes multiple calculations possible without specifying particular scenarios for different $\Delta P_{Gen.Loss}$, without changes in hundreds of *UFLS* models and without numerical convergence problems.

The following conservative assumptions have been made regarding system inertia H and load-to-frequency sensitivity K_f.

The value of the system inertia H was assumed to be 7.5 sec. in accordance with the results of the May 18, 2001 test with 13% of load rejection (tripping 1250 MW of generation in Pacific Northwest), using the following formula:

$$H = \frac{\Delta P}{2} / \frac{\Delta f}{\Delta t}$$

In accordance with the plot, shown in the May 18, 2001 test study, the initial value of $\frac{\Delta f}{\Delta t}$ corresponds to 0.16 Hz of frequency change for 3 sec. or $\frac{\Delta f}{\Delta t} = \frac{0.16/60}{3}$ p.u.

Therefore, $\Delta P = 0.013$, $\frac{\Delta f}{\Delta t} = \frac{0.16/60}{3}$ $and\ H = \frac{0.013 * 3 * 60}{2 * 0.16} \approx 7.5\ sec$ [3]

The assumption for load-to-frequency sensitivity is K_f=1. This assumption is quite conservative as K_f reflects load reduction caused by both frequency and voltage reductions.

Legitimacy of the Simplified Model for this study was confirmed by the following:

- Frequency dynamics for the simplified model and for the regular WECC/GE model are practically identical for initial 5-10 seconds. The results for the same drop of generation are little more optimistic for the simplified model because disturbances in the detailed scheme are additionally aggravated by the increase of system losses.
- The difference after 5-10 sec. is caused mostly by the absence of governors in the simplified model. That can be considered as a reasonable no-reserve assumption for the *UFLS* studies.

The following are some features of adequate *UFLS* in terms of the simplified model:

a) *UFLS* prevents frequency dips lower than an absolutely restricted value $f_{RES.}$ This is possible if:

   - Timely tripped MW's of *UFLS-A* are sufficient to settle frequency at:

$$f_{settling} \geq f_{RES}$$

Using settling conditions $\frac{\partial(\Delta f)}{\partial t} = 0$ for $f = f_{RES}$, equation (1) can be transformed to:

$$\Delta P_{Gen.Loss} \leq P_{UFLS\text{-}A} + K_f * (1 - f_{RES}) * (1 - P_{UFLS\text{-}A})$$

[3] This study calculations were also conducted with a conservative suggestion that system inertia can be as low as 5 sec

Calculations of $\Delta P_{Gen.Loss}$ with K_f =1 and $P_{UFLS\text{-}A}$ =0.2775 (five *UFLS-A* blocks) give the following values:

$\Delta P_{Gen.Loss} \leq$29.9% for $f_{settling} = f_{RES}$=58.2 Hz (new gas turbines)
$\Delta P_{Gen.Loss} \leq$32.0% for $f_{settling} = f_{RES}$=56.5 Hz (5% loss of life)

- Triggering conditions for frequency relays of all five *UFLS-A* blocks occur before a frequency dip reaches f_{RES}, or $f_{A.\,MIN} > f_{RES}$, where $f_{A.MIN}$ - minimum frequency setting of *UFLS-A*. This condition is not violated for f_{RES} = 58.2 Hz, because $f_{A.\,MIN}$=58.3 Hz (Block 5 frequency setting).

- Frequency margin between $f_{A.MIN}$ and f_{RES} is greater than an additional frequency dip during 0.23 sec. (14 cycles) spent on Block 5 relay and circuit breaker operation.

$$\int_{t1}^{t1+0.23} \frac{\partial(\Delta f)}{\partial t} dt \leq f_{A.MIN} - f_{RES} = 0.1\ Hz$$

The simulations have shown that this condition is not a concern, because four blocks trip their loads before the frequency comes to 58.3. The further frequency decline cannot exceed 0.1 Hz for 0.23 sec because it is driven by a less than 6% residual unbalance.

b) *UFLS* limits time of system operation in the whole range of off-frequency conditions (between 58.2/56.5 and 60 Hz). There is no particular specification of those limitations for the new gas turbines (besides t=0 for 58.2 Hz). This study determines the "*UFLS* can handle" time delays for the whole off-frequency range, which could be compared with the new gas turbine limitations, when they become available.

4. System Performance Study

4-1. Simulations with maximum values of $\Delta P_{Gen.Loss}$

As was calculated above:

$\Delta P_{Gen.Loss}$ = 29.9% for $f_{settling} = f_{RES}$=58.2 Hz (new gas turbines)
$\Delta P_{Gen.Loss}$ =32.0% for $f_{settling} = f_{RES}$=56.5 Hz (5% loss of life)

Any of these values of $\Delta P_{Gen.Loss}$ is sufficient to trigger all five *UFLS-A* blocks. Therefore the following analysis of maximum values of $\Delta P_{Gen.Loss}$ assumes that all blocks are triggered.

Figure 1 confirms that a loss of 29.9% of generation prevents frequency dips lower than 58.2 Hz. However, frequency stalls at 58.2 Hz for about 15 sec. Considering, that the "58.2 Hz" requirements allow only instantaneous approach to 58.2 Hz, this frequency stalling can be qualified as a violation.

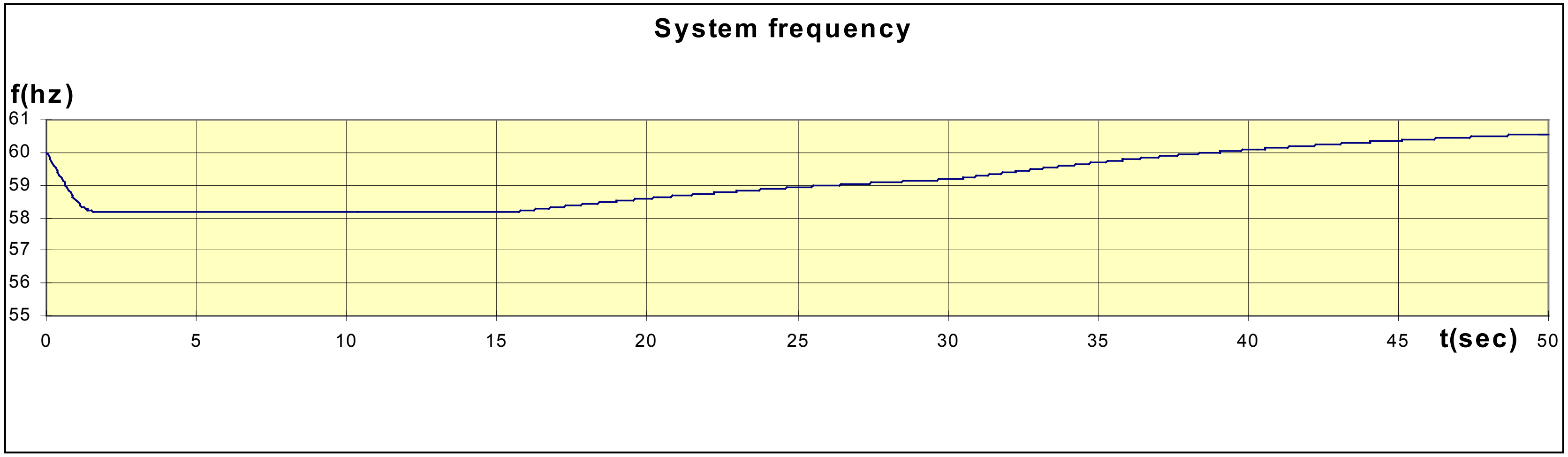
Figure 2 confirms that a loss of 32% of generation prevents frequency dips lower than the 56.5 Hz, allowed by "5% loss of life" requirements. Actually the frequency does not reach the restricted 56.5 Hz level because it would take more than 15 sec. At 15 sec., *UFLS-B* will trigger Block 1, preventing frequency reduction lower than about 57 Hz. However, frequency remains lower than 58 Hz for about 30 sec. This is also a violation, because "5% loss of life" criteria do not allow system operation with 58 Hz for more than 15 sec.

These two simulations demonstrate that the existing *UFLS* could prevent violations of f_{RES} requirements for $\Delta P_{Gen.Loss}$ =29.9% ("58.2 Hz") and for $\Delta P_{Gen.Loss}$ =32.0% (5% loss of life). However, it does not prevent long system operation with frequencies equal or greater than f_{RES} .

A series of calculations were conducted to find maximum $\Delta P_{Gen.Loss}$, not causing any violations. Figure 3 shows that all "5% loss of life" limitations were not violated as long as $\Delta P_{Gen.Loss} \leq 31\%$. Reduction of $\Delta P_{Gen.Loss}$ by 1% reduced the time of system operation with 58 Hz to 15 sec. Therefore compliance with the 15-sec. limitation excludes violations in the whole range from 56.5 to 58 Hz. Timing violations for frequencies above 58 Hz are unlikely because of the relief provided by *UFLS-B* at *t*=15, 30 and 60 sec.

The identical series of calculations for "58.2 Hz" conditions resulted with $\Delta P_{Gen.Loss}$ = 28.4 % (Figure 4). With this value of $\Delta P_{Gen.Loss}$, the frequency comes close to 58.2 Hz, but does not stall and immediately rebounds, reaching 59.0 Hz for 15 sec. The series with system inertia reduced from 7.5 sec. to 5 sec. resulted with 27.5% of maximum $\Delta P_{Gen.Loss}$.

Figure 1. $\Delta P_{Gen.Loss} = 29.9\%$ (f_{MIN}=58.2 Hz –new gas turbine f_{RES} conditions)



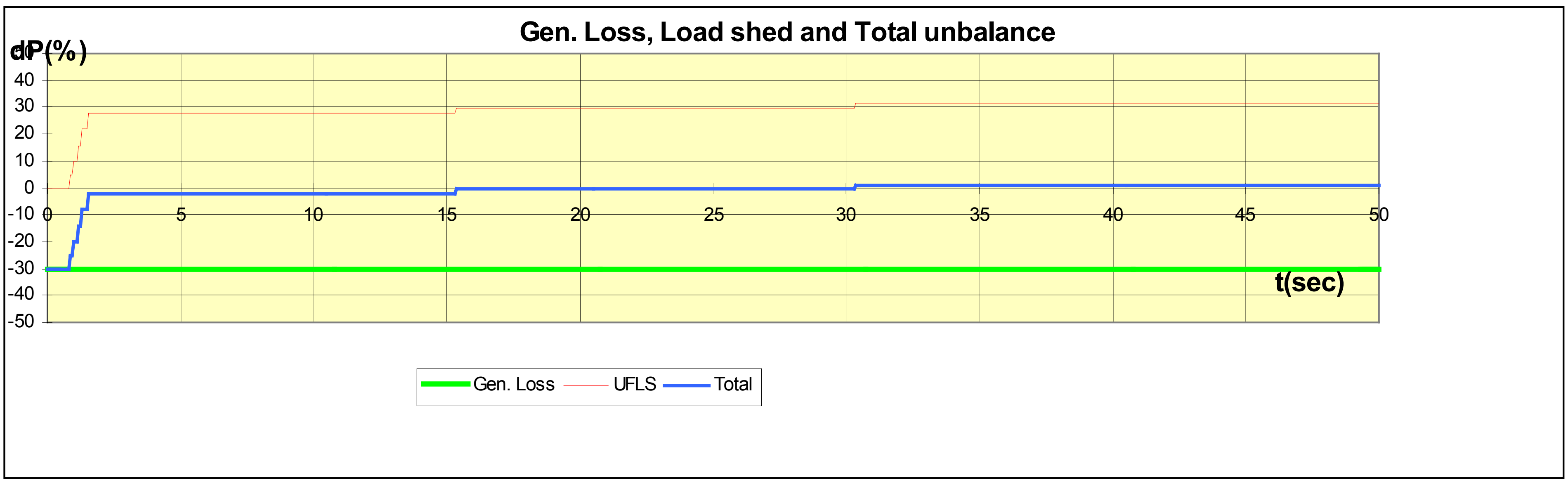
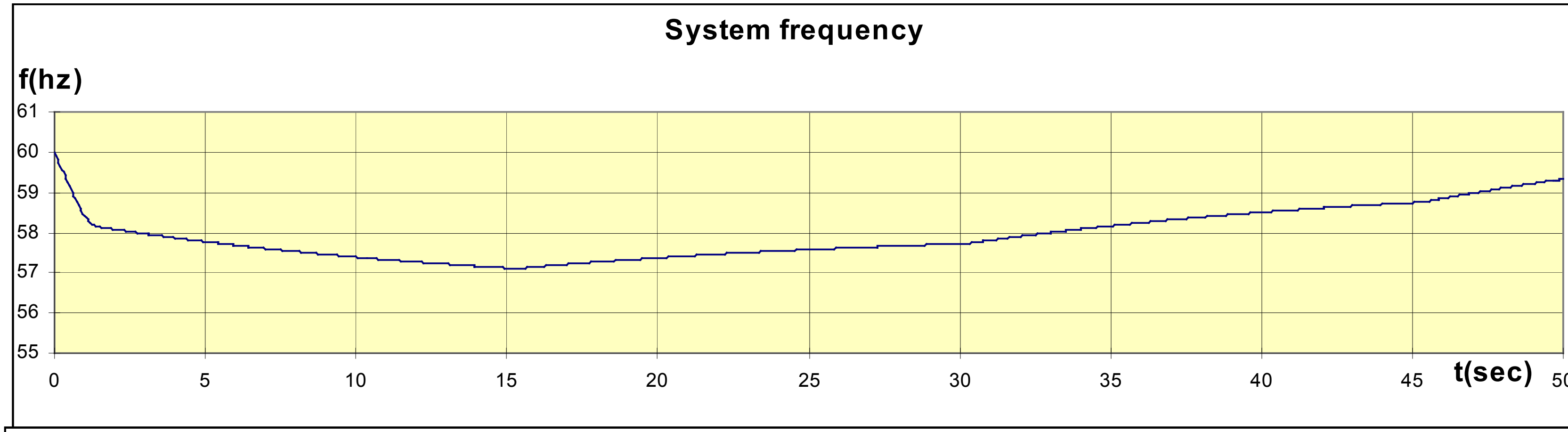


Figure 2. $\Delta P_{Gen.Loss} = 32.0\%$ (f_{MIN}=56.5 Hz – 5% loss of life f_{RES} conditions)



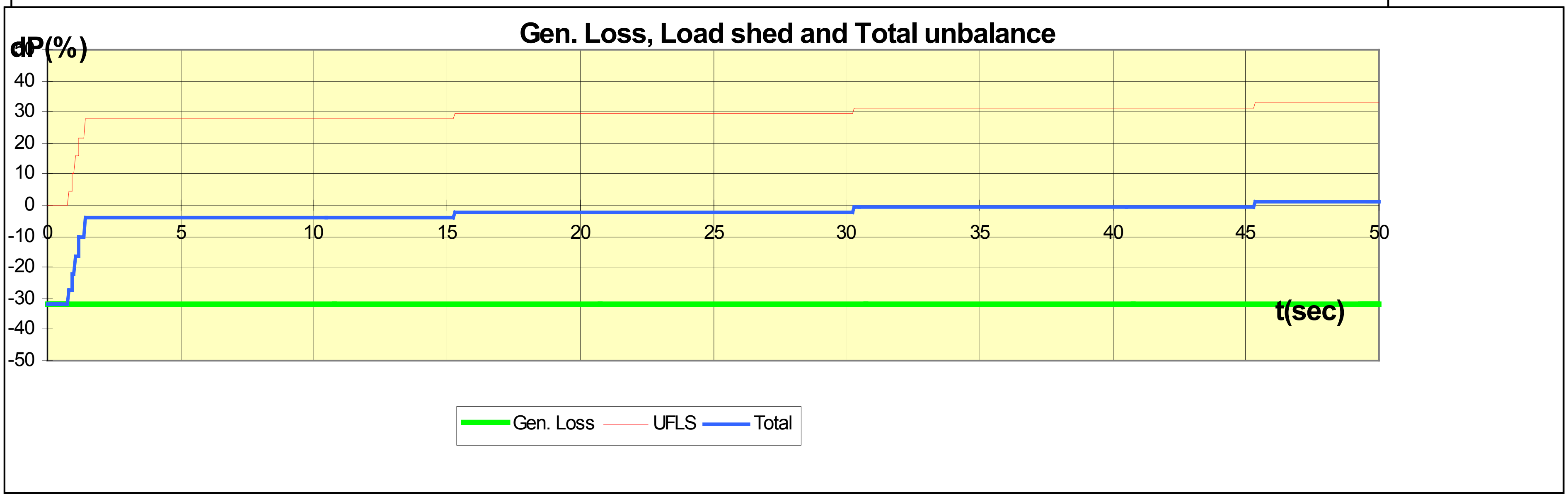


Figure 3. $\Delta P_{Gen.Loss} = 31.0\%$ (t_{58Hz}=15 sec. – 5% loss of life 15 sec. conditions)

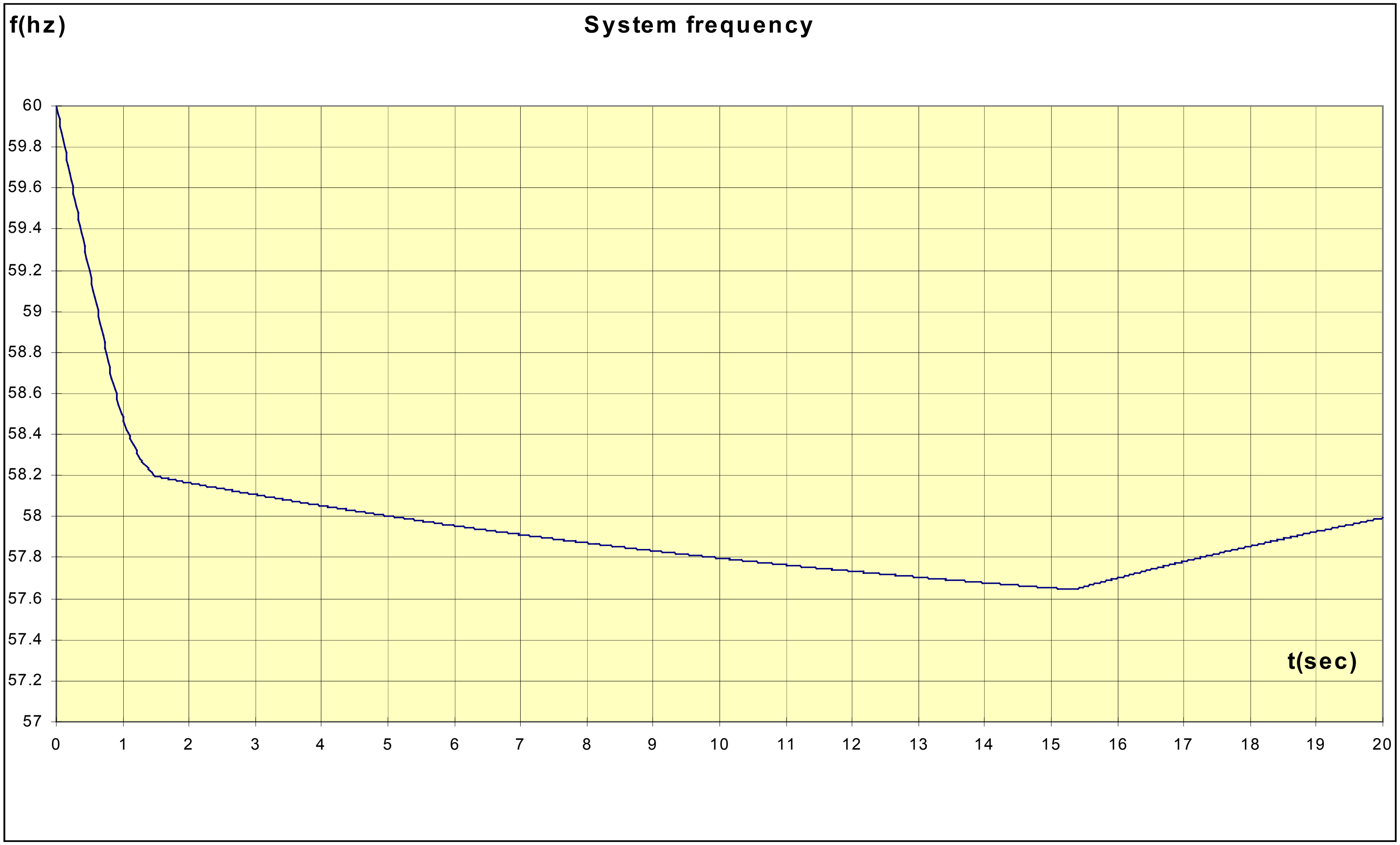
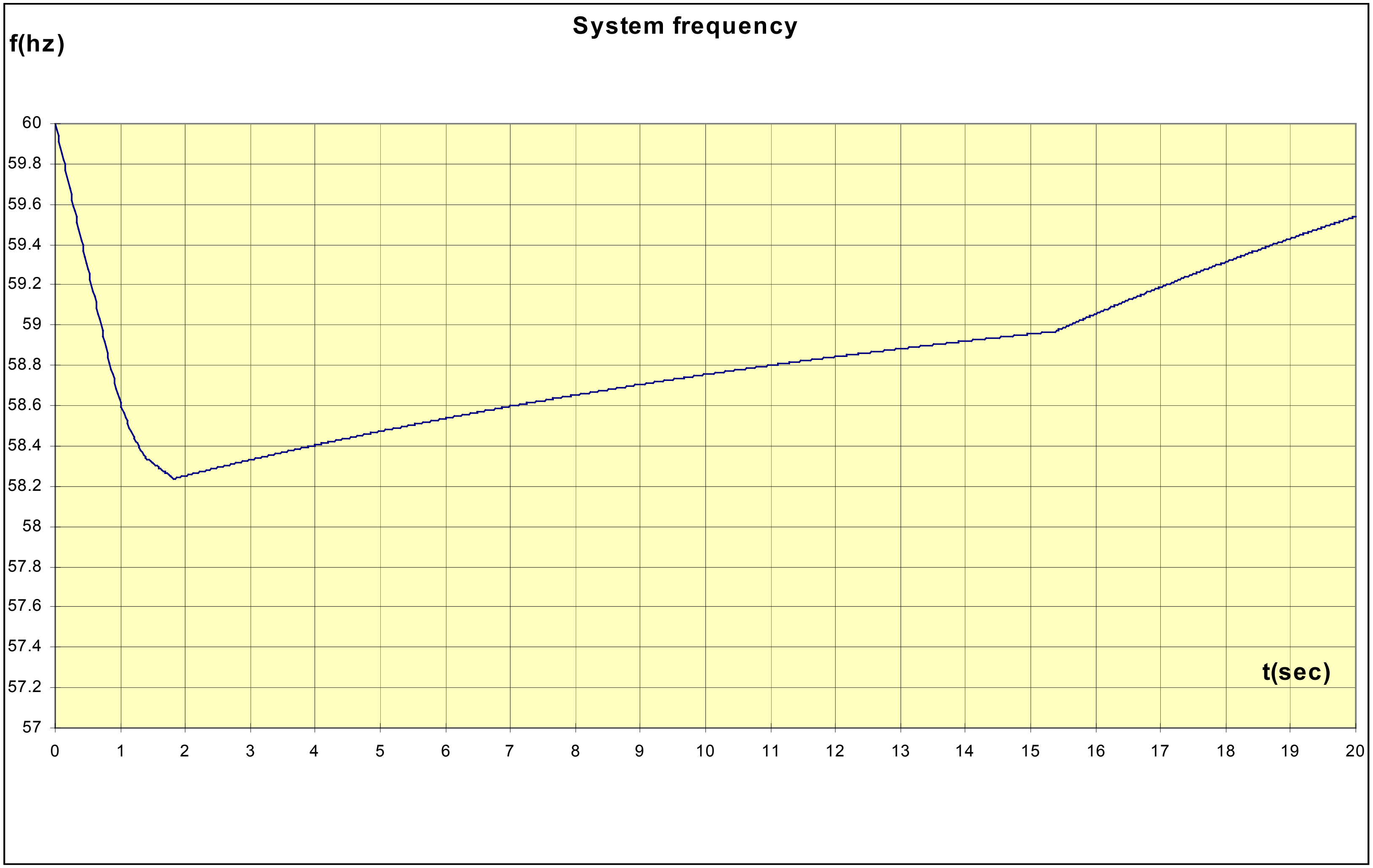


Figure 4. $\Delta P_{Gen.Loss} = 28.4\%$ ($t_{58.2Hz}$=0.0 sec. , t_{59Hz}=15 sec.)



4-2. Simulations with moderate values of $\Delta P_{Gen.Loss}$

The new gas turbines will probably tolerate more than 15 sec. at 59.0 Hz. However, it was shown that maximum values of $\Delta P_{Gen.Loss}$ do not cause violations of the 58.2 Hz condition, if $t_{59Hz} \leq 15$ sec. It is of interest whether this condition would be satisfied for moderate values of $\Delta P_{Gen.Loss}$.

Figures 5-8 demonstrate frequency trajectories for different values of $\Delta P_{Gen.Loss}$ in the vicinity of triggering conditions for different *UFLS-B* blocks. Figure 5 shows that for $\Delta P_{Gen.Loss}$ = 22.6%, which is sufficient to trigger four blocks, $t_{59Hz} \approx 15$ sec. Four blocks are also triggered on 23.1% and 23.6 % of $\Delta P_{Gen.Loss}$, causing system operation with 59 Hz for 17 and 20 sec. correspondingly. Only $\Delta P_{Gen.Loss}$ = 24.2% causes frequency reduction to 58.3 Hz, triggering Block 5. This results with the t_{59Hz} reduction to 11 sec.

Figures 6 and 7 show that t_{59Hz} may exceed 15 sec. for the ranges of $\Delta P_{Gen.Loss}$, which are close to triggering conditions of blocks 3 and 4. Figure 8 shows that this is impossible in the vicinity of Block 2 triggering conditions.

The diagram shown in Figure 9 generalizes the results of these simulations.

It should be noted that application of conventional *UFLS-A* (58.3-59.1 Hz) does not create a concern that "5% loss of life" limitations could be violated on moderate $\Delta P_{Gen.Loss}$. If $\Delta P_{Gen.Loss}$ is barely covered by certain *UFLS-A* block and frequency stalls between settings of two blocks, anti-stalling *UFLS-B* triggers at 15 sec. and increases frequency to a secure value.

This *UFLS-B* action does not resolve the situation if system operation in the range 58.3-59.1 Hz is allowed for less than 15 sec. This means that the new frequency limitation is not ordinary for the existing *UFLS* design and requires verification of system performance for moderate values of $\Delta P_{Gen.Loss}$.

Figure 5. $\Delta P_{Gen.Loss}$=*24.2%* triggers Block 5.
t_{59Hz}>*15 sec*. for *22.6%*<$\Delta P_{Gen.Loss}$<*24.2%*

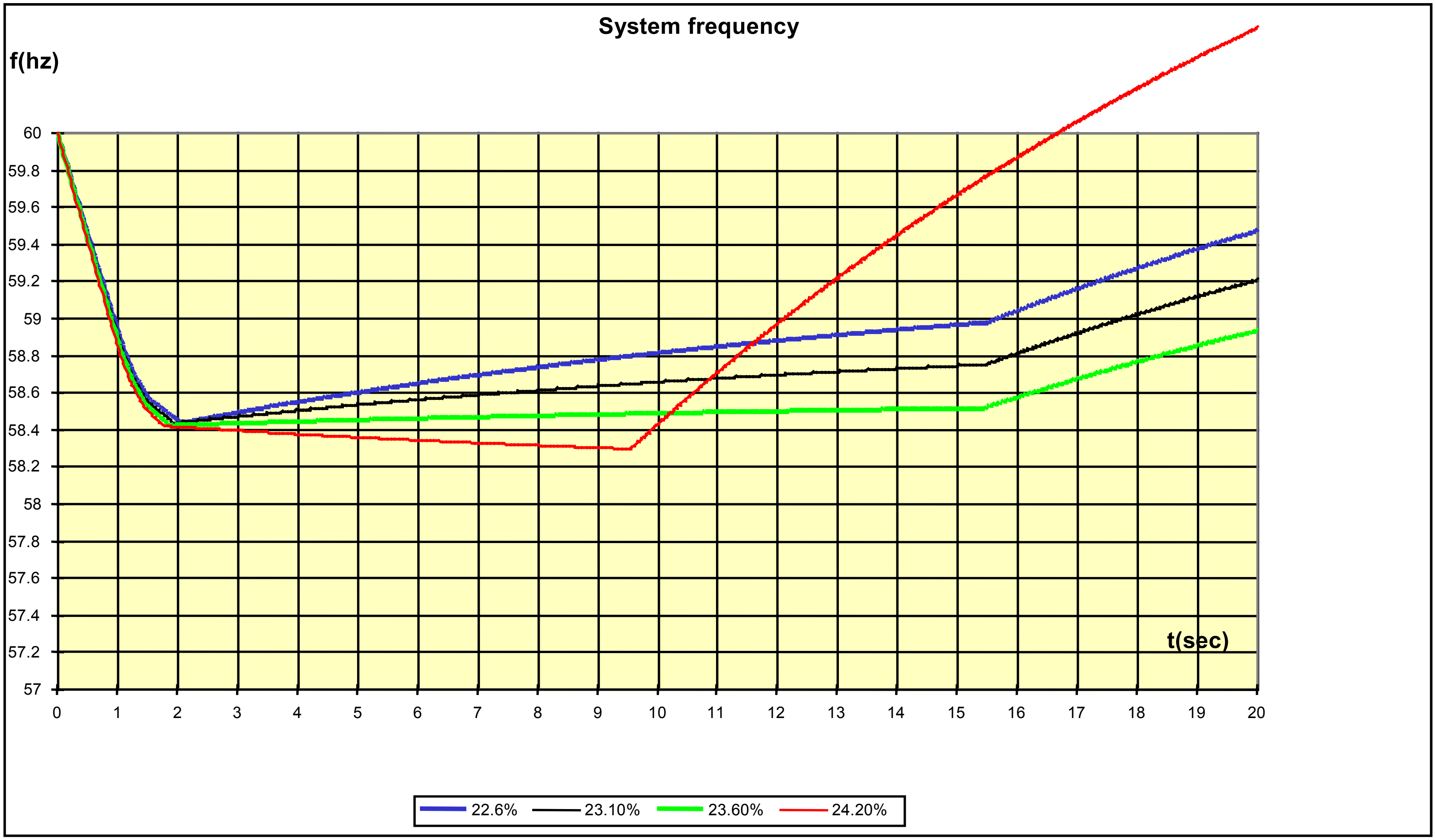


Figure 6. $\Delta P_{Gen.Loss}=18.2\%$ triggers Block 4.
$t_{59Hz}>15$ *sec*. for $17.0\%<\Delta P_{Gen.Loss} 18.2\%$

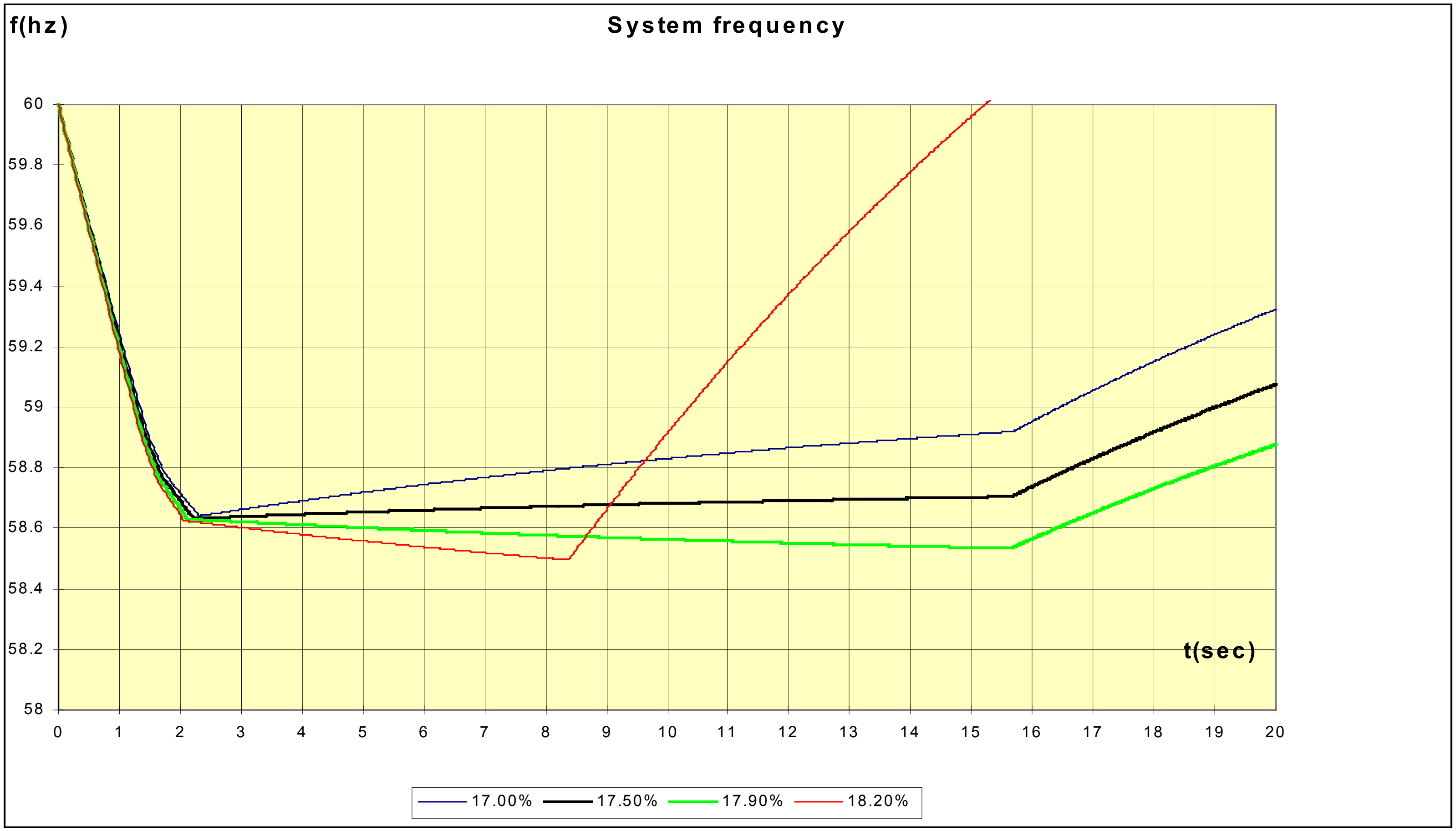


Figure 7. $\Delta P_{Gen.Loss}$=12.3% triggers Block 3.
t_{59Hz}>15 sec. for 11.6%<$\Delta P_{Gen.Loss}$12.3%

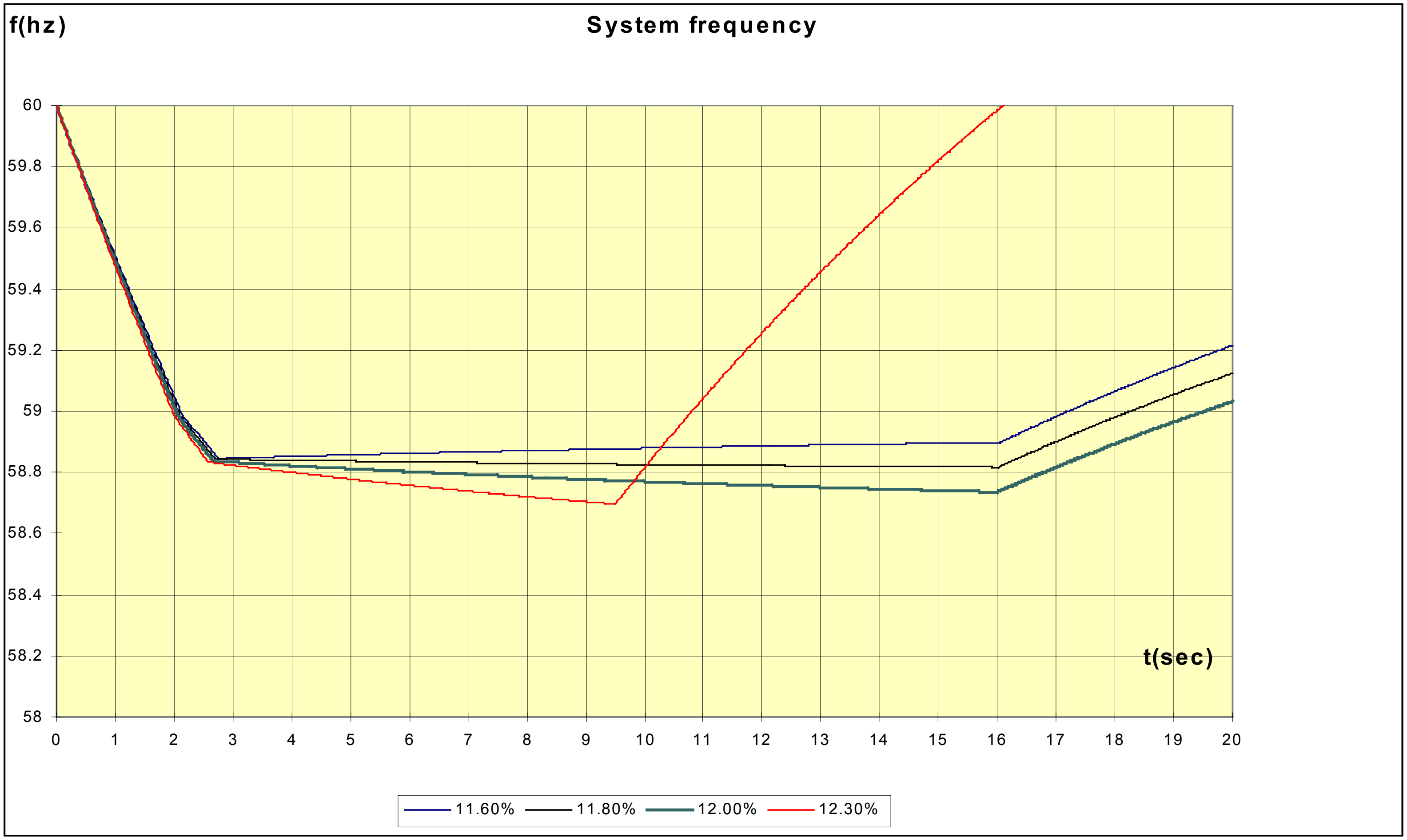


Figure 8. $\Delta P_{Gen.Loss}=6.6\%$ triggers Block 2. $t_{59Hz}<15\ sec.$

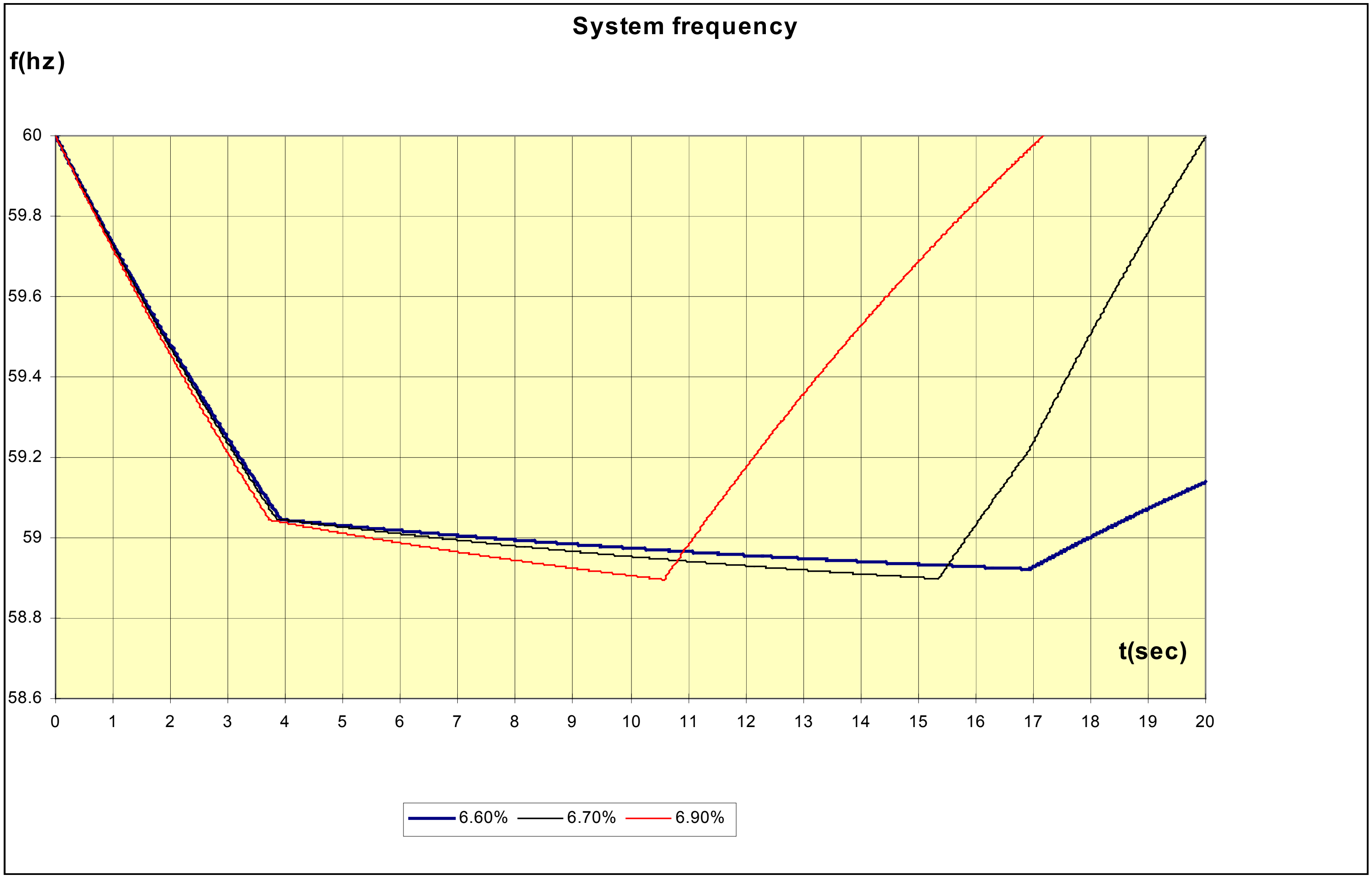
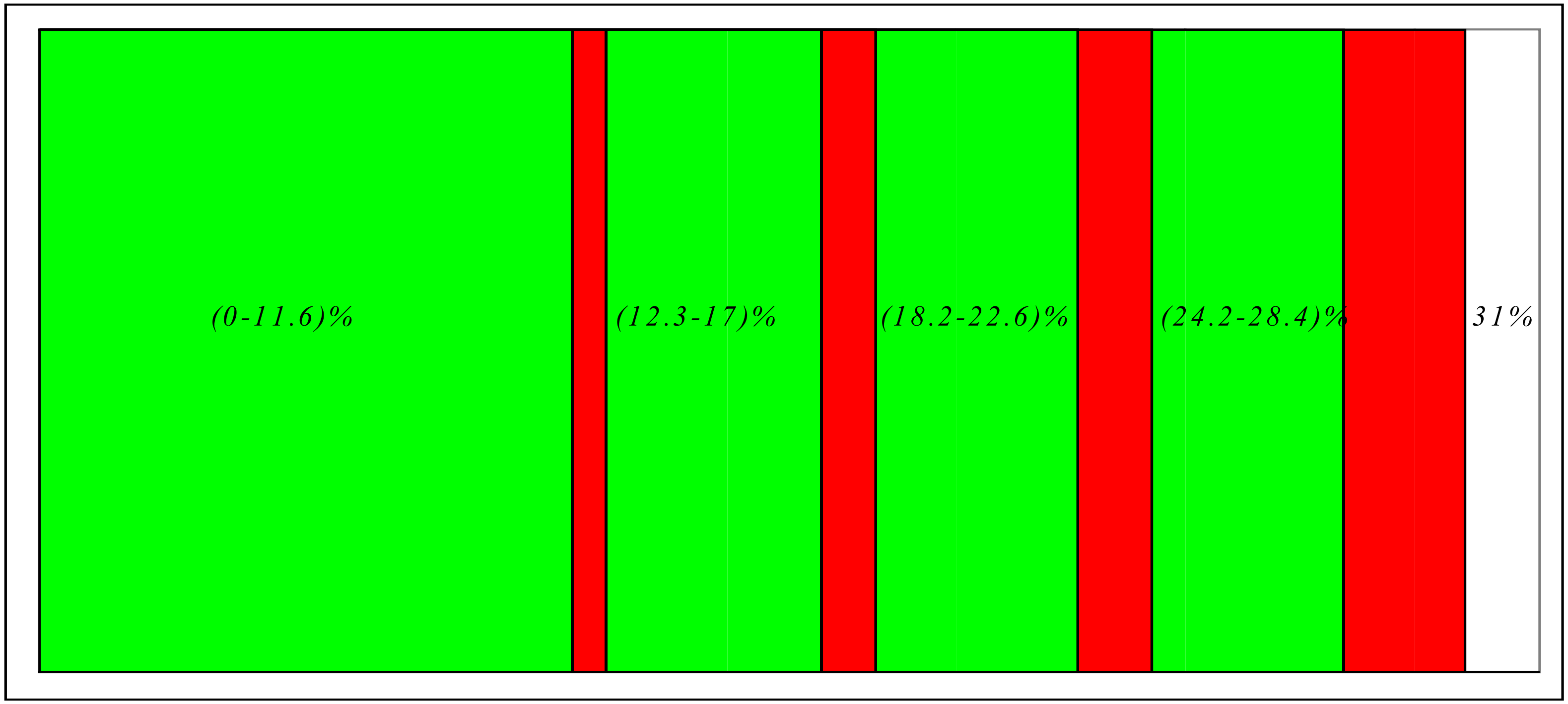


Figure 9. System performance for □$P_{Gen.Loss}$ between 0 and 31%.
Green - t_{59Hz}<*15 sec*., Red - t_{59Hz}>*15 sec*.



4-3. The Maximum Time Intervals of System Operation with Different Off-nominal Frequencies

Consideration of frequency trajectories in Section 3-2 revealed that the existing *UFLS* does not guarantee that system operation with frequency less or equal to 59 Hz will be limited by 15 sec. (even with $\Delta P_{Gen.Loss}$ reduced to 28.4/27.5%). However, the condition $t_{59Hz} \leq 15$ sec., essential for maximum $\Delta P_{Gen.Loss}$, could be too stringent for lesser loss of generation.

An objective conclusion about sufficiency of existing *UFLS* to satisfy the new requirements could be made with a specification of new gas turbine time limits for frequencies above 58.2 Hz. However, these limits were not available in the course of the study. Therefore, this study does not provide a final conclusion about *UFLS* sufficiency, but derives the worst system performance with existing *UFLS*. This performance (the maximum time intervals of system operation with different frequencies) could be compared with the specified limitations, as soon as they become available.

The search for the worst system performance was organized by variation of the $\Delta P_{Gen.Loss}$ magnitude and system inertia *H* (7.5 or 5 sec.). The frequency plots, similar to the plots on figures 5-8, have been built for different combination of these two parameters. Table 2 shows the most important parameters, derived from these plots.

Table 2.
Durations (sec.) of system frequency dips caused by instantaneous loss of generation with operation of existing *UFLS*.

f (Hz)	Gen.loss=30.0%		Gen.loss=28.4%		Gen.loss=27.5%		Gen.loss=24.0%*	
	H=7,5sec	H=5sec	H=7,5sec	H=5sec	H=7,5sec	H=5sec	H=7,5sec	H=5sec
59.50	32.5	30.5	19.0	17.0	15.5	11.5	29.0	24.0
59.00	25.5	22.0	15.0	11.0	8.0	6.0	20.0	18.0
58.80	22.0	20.0	10.0	7.5	6.0	4.2	17.2	16.5
58.60	19.0	18.0	6.0	4.5	4.0	3.0	15.0	15.0
58.40	16.5	16.0	3.0	2.5	2.0	1.5	8.0	9.0
58.30	14.5	15.0	1.0	1.1	0.8	1.0	1.0	1.2
58.20	**8.0!**	**14.5!**	0.0	**0.4!**	0.0	0.0	0.0	0.0
58.10	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0
58.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

The first four columns of Table 2 reconfirm that the existing *UFLS* is not able to prevent violations of the "58.2 Hz" limit for 30 % of $\Delta P_{Gen.Loss}$ and even for 28.4% of $\Delta P_{Gen.Loss}$

if system inertia is reduced to 5 sec. Only reducing $\Delta P_{Gen.Loss}$ to 27.5% provides $t_{58.2Hz}$ =0 in the whole range of parameter variations.

The columns for 27.5% show short frequency durations above 58.2 Hz, because that level of $\Delta P_{Gen.Loss}$ initiates all five blocks of *UFLS-A*. It is interesting that simulations with *H*=7.5 sec. have shown greater durations for frequencies above 58.4 Hz than simulations with *H*=5 sec. This is because system inertia has varying affects on the different stages of system operation in the off-nominal range. For example, system inertia reduction increases frequency dips but accelerates frequency restoration.

The analysis of the trajectories for $\Delta P_{Gen.Loss} \leq 27.5\%$ revealed that the maximum durations of system operation with off-nominal frequencies correspond to a $\Delta P_{Gen.Loss}$ of about 24%, which is able to initiate a trip of four *UFLS-A* blocks, but insufficient to trip five blocks. This is illustrated in the last two columns of Table 2.

The maximum of two numbers for given frequency in these last columns is a maximum time of system operation with that frequency. These numbers are combined in the first column of Table 3.

Table 3
UFLS Can Handle Table

f (Hz)	UFLS can handle (sec.) for Gen,loss≤27.5%		UFLS can handle (sec.) for Gen.loss≤30%	
	No margin	5 sec margin	No margin	5 sec margin
59.50	29.0	34.0	32.5	37.5
59.00	20.0	25.0	25.0	30.0
58.80	17.2	22.2	22.0	27.0
58.60	15.0	20.0	19.0	24.0
58.40	9.0	14.0	16.5	21.5
58.30	1.2	6.2	15.0	20.0
58.20	0.0	0.0	14.5	19.5
58.00	0.0	0.0	0.5	5.5
57.80	0.0	0.0	0.0[4]	0.0

The numbers in the second column of Table 3 contain the 5 sec. margin. The number for 58.2 Hz was not increased because this would contradict with the known requirement.

Columns 3 and 4 show that the existing UFLS would handle $\Delta P_{Gen.Loss}$=30% if manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust turbine protection allowing immediate trip only at 57.8 Hz.

[4] This point corresponds to the results of calculations for the non-simplified WECC scheme.

It is very likely that numbers in Table 3 might satisfy the manufacturers. However, the correspondence between sizes of *UFLS* blocks, specified in the WSCC Program, and their actual sizes becomes very critical. This was not so critical for the “5% loss of life” requirements.

5. Possible solutions to satisfy the ”58.2 Hz” requirements

The following four solutions require different UFLS modifications, which may cause an additional and probably quite frequent load trip. Therefore, these solutions should be considered only if: 1) frequency deviations/durations shown in the *“UFLS Can Handle Table”* are not acceptable; 2) credibility of the 30% study base is not refuted.

5-1. Solution 1

Increase UFLS-A

For the increase of UFLS capability above 27.5% of $\Delta P_{Gen.Loss}$ by x%, approximately x% of additional load should be connected to the *UFLS-A* blocks. This additional load would have the highest probability of tripping if it is connected to Block 1 with the highest frequency setting. An increase of Block 1 moves “blind spots” to less credible $\Delta P_{Gen.Loss}$ values while an increase of Block 5 would reduce the probability of an excessive load trip.

These modifications would be sufficient if the manufacturers accept gas turbine operation in the range above 58.2 Hz with frequency deviations/durations, specified in the *“UFLS Can Handle Table”* and readjust turbine protection if necessary.

5-2. Solution 2

Implement the system of balancing a protective loss of gas units by the immediate direct trip of loads.

This solution does not require manufacturer approval and turbine protection readjustment. However, implementation of this solution is very difficult because additional loads should not be involved in the existing *UFLS* blocks and should be specific for each gas unit. The total amount of direct trip load for each combine cycle unit should cover also a steam turbine, which can be lost very soon after a gas turbine.

Reliability concerns make direct load tripping less preferable than decentralized *UFLS*. The system cost would be very significant. The total percentage of involved loads in some areas could be very significant and include tripping of vulnerable customers.

5-3. Solution 3

1)Increase UFLS-A and 2)adjust frequency relay settings to provide uniform load distribution between 59.1 and 58.3 Hz with 0.01 increment instead of aggregating loads in the five blocks with 0.2 Hz increment.

The second part of this solution would eliminate the "blind spots" by drawing adjacent frequencies together. Therefore, this solution does not require manufacturer approval and gas turbine protection readjustment.

This measure would also make significant excessive load trips impossible. Those excessive load trips are unavoidable with the block-wise structure of *UFLS*.

UFLS with the uniform load distribution trips an accurate amount of load in the whole off-nominal operating range. This creates advantages, which are important beyond the "58.2 Hz" issue. The uniform load distribution allows some redundancy in a cumulative amount of load, available for tripping at different frequencies, and in total load, which could be tripped by *UFLS*. With such a possibility, the uncertainty in determination of maximum $\Delta P_{Gen.Loss}$ is not a problem because it could be covered by some redundancy without a risk of an excessive load trip.

Drawing together frequencies of the existing discrete blocks could also eliminate the "blind spots" but significantly increases probability of an excessive load trip.

5-4. Solution 4

1)Increase UFLS-A and 2) arrange circuits for some loads of Blocks 3, 4 and 5, which trip those loads if system stalls for about 5 sec. with frequency, lower than a main block setting by 0.1-0.2 Hz.

This arrangement trips load of a given block after an indication of frequency stalling in the "blind spot" at the end of the preceding block and implies utilization of additional outputs of the same frequency relays

6. Conclusions

1. Existing *UFLS-A* provides $f_{settling}$=58.2 Hz on about 29.9% loss of generation. Even with this reduced $\Delta P_{Gen.Loss}$, system performance does not satisfy the new

requirements, because frequency stalls at 58.2 Hz and stays at this level for about 15 sec. until initiation of *UFLS-B*.

2. The "58.2 Hz" requirements are satisfied for $\Delta P_{Gen.Loss} \leq 27.5$ %, if this $\Delta P_{Gen.Loss}$ is sufficient to trigger all five blocks of *UFLS-A*. If $\Delta P_{Gen.Loss} = 27.5$ %, frequency comes closely to 58.2 Hz, but does not stall and immediately rebounds, reaching 59.0 Hz for 15 sec.

3. The new frequency limitations are not ordinary for the existing *UFLS* design and require verification of system performance for moderate values of $\Delta P_{Gen.Loss}$. System frequency may stall in "blind spots" between settings of two blocks of *UFLS-A* for 15 sec. until *UFLS-B* trips additional load. This verification is not necessary with the "5% loss of life" limitations allowing 15-sec. operation in all possible "blind spots".

4. The developed "*UFLS Can Handle*" table gives maximum durations of system operation with different off-nominal frequencies, which might be caused by $\Delta P_{Gen.Loss} \leq 27.5\ \%$ or $\Delta P_{Gen.Loss} \leq 30\ \%$ in the WECC system, equipped by existing *UFLS*. These durations represent the abilities of particular UFLS system and should not be confused with any equipment limitations (such as 5% loss of life).

UFLS Can Handle Table

f(Hz)	Time (sec) for Pgen.loss≤27.5%	Time (sec) for Pgen.loss≤30%
59.5	<34.0	37.5
59.0	<25.0	30.0
58.8	<22.2	27.0
58.6	<20.0	24.0
58.4	<14.0	21.5
58.3	<6.2	20.0
58.2	0.0	19.5
58.0	0.0	5.5
57.8	0.0	0.0

5. The existing UFLS system would handle $\Delta P_{Gen.Loss} = 30\%$ (second column in the Table), if the generator manufacturers reconsider the risk of turbine operation with frequencies lower than 58.2 Hz and readjust protection allowing immediate trip only at 57.8 Hz. The 2.5% *UFLS* capability reduction (from 30 to 27.5%) would occur if the manufacturers confirm the time intervals only in the first column of this Table.

6. Reduction of the time intervals in the Table is also possible if actual requirements happen to be more severe. This study considers three different options for such a reduction. However all of those options require readjustments and most likely modifications and replacement of some of the frequency relays.

7. It is very likely that system performance with existing (or increased by 2.5%) *UFLS* may satisfy the generator manufacturers. However, the correspondence between the *UFLS* block sizes, specified in the 1997 WSCC Plan, and their actual sizes becomes very critical. This was not so critical for the "5% loss if life" conditions.

Appendix 6

Performance of Under-frequency Load Shedding System for Gradual Loss of Generation

Performance of Underfrequency Load Shedding System with a Gradual Loss of Generation

1. Background

The existing WECC Underfrequency Load Shedding System (*UFLS*) consists of the *UFLS-A* and *UFLS-B* sub-systems (Table 1). *UFLS-A* refers to the five fast acting blocks with different frequency settings and *UFLS-B* refers to the three anti-stalling blocks with different time delays.

Table 1. WSCC Coordinated Off-Nominal Frequency Load Shedding Plan

UFLS-A - instantaneous *UFLS* (14 cycles)	*UFLS-B* - anti-stalling *UFLS*
Block 1 - 59.1 Hz, 4.75%,	Block 1 – 59.3 Hz, 2%, 15 sec.
Block 2 - 58.9 Hz – 5.25%,	Block 2 – 59.5 Hz, 1.5%, 30 sec.
Block 3 - 58.7 Hz – 5.75%,	Block 3 – 59.5 Hz, 1.78%, 60 sec.
Block 4 - 58.5 Hz – 6.0%,	
Block 5 - 58.3 Hz – 6.0 %	

UFLS-A is designed to provide an immediate action, preventing a deep system frequency decline caused by a sudden and significant loss of generation. *UFLS-B* restores frequency to the non-dangerous level (59.5 Hz) if *UFLS-A* does not raise frequency to that level or an additional minor loss of generation occurs after frequency restoration.

This *UFLS* structure could be less effective for a more common gradual loss of generation, which may occur in the following or similar situations:

1. Cascade loss of generators, initiated by a fault related system stress, accompanied by correct or incorrect operations of relay protection, overexcitation protection, turbine underfrequency protection, out-of-step devices, etc.

2. Gradual power plant or large unit generation reduction because of a failure in an auxiliary system.

3. Gradual generation loss scenario may occur if a more impulsive loss is initially suppressed by the actions of temporarily responsive FRR units. Their initial fast response may be followed by unloading because of the delayed boiler response to a new level of generation.

The most of the significant generation loss occurrences are actually gradual and many of them are described in literature [1, 2]. There is also the longstanding overseas experience in application of the simple *UFLS* modification, increasing its effectiveness on a gradual loss of generation [2].

This study investigates WECC system performance on gradual generation losses with different profiles and sizes. Some of the simulations were also conducted for the PG&E part of the regular WECC/GE model and resulted in the practically identical frequency dynamics.

This report illustrates the possibility of ineffective *UFLS* operation on a gradual loss of generation and some measures for *UFLS* correction. The slower the system deficit development, the more essential these corrections.

Some arguments could be made that a more detailed analysis of the slow generation loss potential should be conducted to recommend those corrections for a wide implementation in the WECC system. Such an analysis could indeed enhance the reasoning for the corrections. However, it should be recognized that *UFLS* is the last line of system defense, which should be invariant to the generation deficit causes and their probabilities.

2. System Performance Study

2-1. System performance with existing UFLS

Figure 1 illustrates the frequency trajectory and the sequence of events, which follows the instantaneous loss of generation. The 23.8% deficit causes fast frequency reduction with firm operation of the four *UFLS-A* blocks (at 59.1, 58.9, 58.7 and 58.5 Hz), arresting frequency at about 58.4 Hz. These blocks trip 4.75 + 5.25 + 5.75 + 6.0 = 21.75% of system load in less than two seconds. Further frequency restoration starts when the first block of *UFLS-B* times out its 15-second time delay and drops the additional 2% of load.

This sequence of events features initial immediate operation of the *UFLS-A* blocks, arresting frequency by tripping about the deficit size volume of load, and the corrective action of *UFLS-B*, restoring frequency to the secure level. This is the case of effective *UFLS* operation because the sequence of events corresponds to *UFLS* design and guarantees that volumes of *UFLS-A* and *UFLS-B* are sufficient to overcome a maximum loss of generation counted in that design.

Figure 2 illustrates a gradual loss of just 9% of generation. Due to the slow deficit increase (9% for 2-3 minutes) and the actions of *UFLS-B* accompanying this increase, the frequency dip is insignificant and does not reach the setpoints of *UFLS-A*. Eventually, this disturbance results in the trip of all three *UFLS-B* blocks and frequency stalling at 59.11 Hz. The abilities of *UFLS-B* have been exhausted but the frequency level is too high to trigger even the first block of *UFLS-A* (59.1 Hz). An absence of a generation reserve at this stage of the process is a reasonable no-reserve assumption for the *UFLS* studies. Furthermore, the gradual generation loss scenario could occur, because a more impulsive loss was initially suppressed by the actions of temporarily responsive units. Therefore, this simulation is an example of ineffective *UFLS* operation, which is armed by sufficient amount of load but fails to detect the abnormal conditions.

The described situation probably could not occur on a rapider loss of generation because frequency would decline to 59.1 Hz and trigger *UFLS-A* before *UFLS-B* times out. The following examples of ineffective *UFLS* operation on a gradual generation loss could also give different results with a faster deficit increase. However, *UFLS* should be invariant to the generation deficit causes and operate effectively even on low probability events.

Figure 3 illustrates a gradual loss of 21.5% of generation causing frequency stalling at 58.7 Hz. The generation loss scenario includes the first rapid stage with the loss of about 12 % for 8-10 seconds and the second slow stage with the loss of 9.5% for about 2 minutes. Such a scenario could be associated with a gradually increasing participation of hydro resources in balancing a developing emergency deficit.

The first stage caused a frequency dip to 58.9^{-} Hz, sufficient to trigger the first two *UFLS-A* blocks. These actions, along with operation of the first block of *UFLS-B*, restored frequency to almost 60 Hz. The continuing loss of generation caused the new frequency decline accompanied by operation of the remaining blocks of *UFLS-B*. The first vacant block of *UFLS-A* is the third block with the 58.7 Hz setting. Therefore, nothing is going to oppose frequency decline until reaching 58.7 Hz.

PG&E and some other utilities practice *UFLS* enhancement by tripping interruptible customers when frequency reaches 59.65 Hz. These actions increase a part of load to be tripped with minor frequency deviations and make this part less dependant on a generation loss scenario. Figure 5 shows that this practice does not eliminate the gradual loss concern. An addition of a block, tripping 2% of interruptible customers, creates the same frequency stalling situations on a 23.5% generation loss as on a 21.5% generation loss without those 2%.

2-2. System performance with modified UFLS

All described in section 2-1 plots correspond to the *UFLS* structure, presented in Figure 5. Actually, each of *UFLS* block trips loads of many substations. For the purpose of this study, loads of each *UFLS-A* block are presented by two portions (L1 and L2 for Block 1, L3 and L4 for Block2, etc.). Single loads L11-L17 present actions of *UFLS-B* blocks.

The described low-frequency stalling situations can be prevented with the application of doubled *UFLS-B* blocks (4.6, 3.4 and 4% instead of 2.3, 1.7 and 2%). Figure 6 illustrates the frequency trajectory for the same 23.5% loss as in Figure 4. Operation of the three double blocks of *UFLS-B* restores frequency to about 59.9 Hz instead of 58.7 Hz.

However, an addition of 6% of system load to *UFLS-B* is very undesirable because:

- This is an expensive and laborious solution.

- This solution can cause excessive load trip and frequency overshoot in the instantaneous generation loss situations.

- Additional *UFLS-B* customers would be more sensitive to power interruptions than presently connected ones.

The *UFLS* structure, presented in Figure 7, reduces the probability of low frequency stalling on a gradual generation loss and does not require any expansion of *UFLS* blocks [2]. This structure features an arrangement of the additional tripping circuits of loads L1, L3, L5, L7 and L9. These loads are originally connected only to the *UFLS-A* blocks. The new circuits provide their trip from the additional relays with the *UFLS-B* settings or from the second outputs of the modern underfrequency relays ("joint trip").

Similarly with the Figure 6 example, the total amount of *UFLS-B* load was increased from 6% to 12%. Load fractions and time setting of the additional circuits provide somewhat uniform distribution of total *UFLS-B* capability between 15 and 60 seconds. An additional study might be conducted to determine an optimal fraction of *UFLS-A* load to be equipped by the *UFLS-B* tripping circuits. Publication [2] recommends an arrangement of the "joint" trip for 40% of *UFLS-A* loads.

Figure 8 illustrates operation of *UFLS* with the "joint trip" structure. For the same 23.5% loss of generation, this structure restores frequency to about 59.8 Hz instead of 58.7 Hz. Similarly to Figure 5, operation of *UFLS* starts from tripping two blocks of *UFLS-A* and two regular blocks of *UFLS-B*. The further actions bring frequency to 58.7 Hz by tripping the "joint" fractions of the still vacant blocks 3, 4 and 5 of *UFLS-A* (0.85+0.85+2=3.7%). The third regular block of *UFLS-B* would be initiated in the case of the farther deficit increase.

An instantaneous loss of generation may trip more *UFLS-A* blocks, disabling more of the "joint" fractions. However, capability of the regular *UFLS-B* blocks is not affected and should be sufficient in such cases.

Figure 9 is the one more example of successful operation of the modified *UFLS* on a 9% gradual loss of generation. Unlikely to Figure 2, operation of *UFLS* was sufficient due to the trips of the two regular blocks of *UFLS-B* (2.3+1.7=4%) and the "joint" fractions of the four *UFLS-A* blocks (1.15+1.15+0.85+0.85=4%). The third regular and the fifth "joint" block of *UFLS-B* would be initiated in the case of the farther deficit increase.

Therefore, the "joint trip" *UFLS* structure, presented in Figure 7, is more effective than the structure with doubled *UFLS-B* blocks because:

- This structure is much less expensive and laborious. It trips only the loads, which are presently connected to *UFLS*, and the majority of the tripping circuits can be arranged from the second outputs of the existing underfrequency relays.

- The "joint trip" structure does not change the maximum size of the *UFLS-B* blocks and cannot cause an excessive load trip and frequency overshoot in instantaneous generation loss situations.

- The "joint trip" structure does not require *UFLS* expansion by additional customers, which are most likely more sensitive to power interruptions. It does not change the original tripping priorities for the presently connected customers.

3. Conclusions

1. A part or all of *UFLS-A* blocks may not participate in balancing a gradual generation loss because the leading *UFLS-B* actions prevent deep frequency declines.

2. When some of *UFLS-A* blocks do not participate, the 6% of system load connected to *UFLS-B* (20% of *UFLS-A*) are not enough to prevent frequency stalling at 58.7 Hz or even lower.

3. Insufficient *UFLS-A* participation is less likely on a rapider loss of generation. However, *UFLS* should be invariant to generation deficit causes and operate effectively even on low probability events.

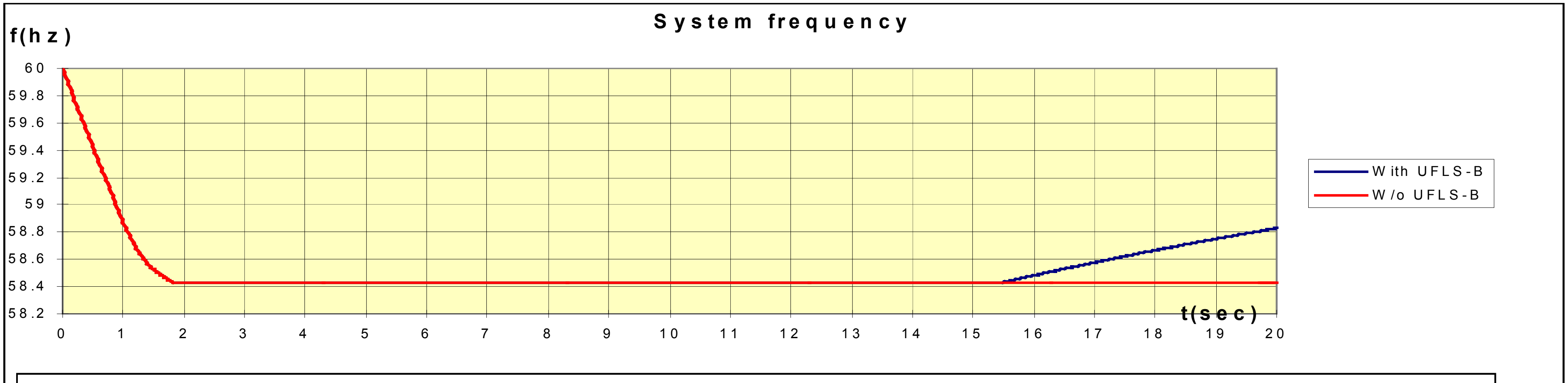
4. The possible solution, providing more effective utilization of the *UFLS* blocks, is implementation of additional *UFLS-B* circuits for the trip of some loads presently connected to *UFLS-A*.

References

[1] C. W. Taylor, D. C. Erickson, "Recording and Analyzing the July 2 Cascading Outage," IEEE Computer Applications in Power, Vol. 10, No. 1, pp. 26-30, January 1997.

[2] G. D. Butin, N. S. Markushevich, M. G. Portnoy, R. S. Rabinovich, S. A. Sovalov, E. D. Zelilidzon, "Automatic Frequency Load Shedding in USSR Power Systems", CIGRE. 1972

Figure 1. *UFLS-A* and *UFLS-B* actions on an instantaneous loss of 23.8% of generation



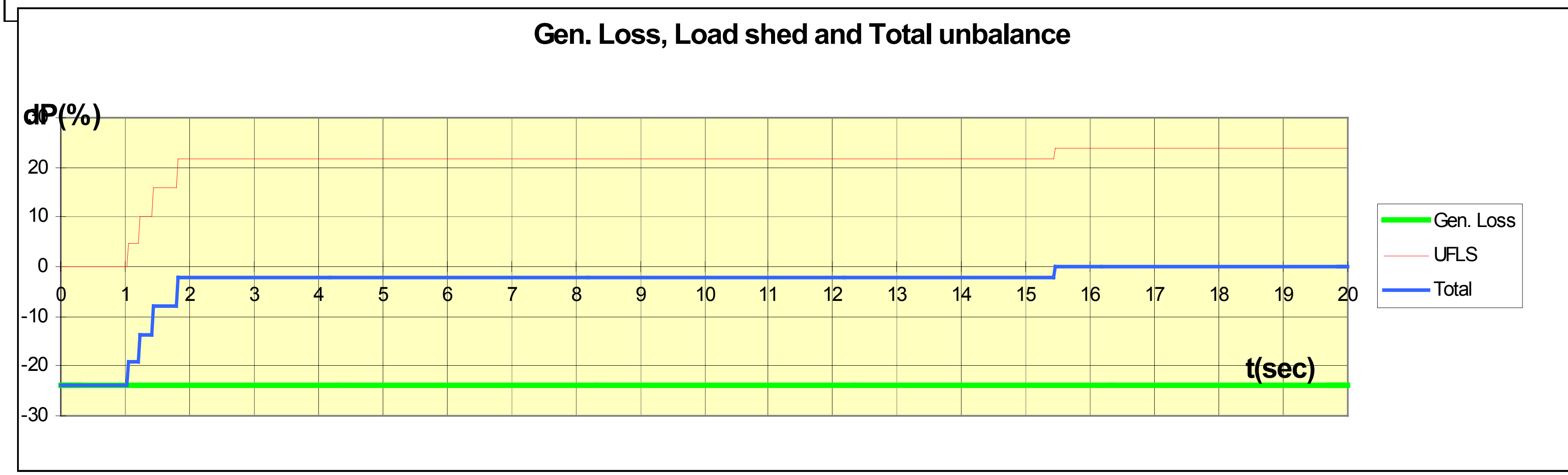


Figure 2. Gradual loss of 9% of generation triggers 3 blocks of *UFLS-B*. Frequency stalls at 59.11 Hz

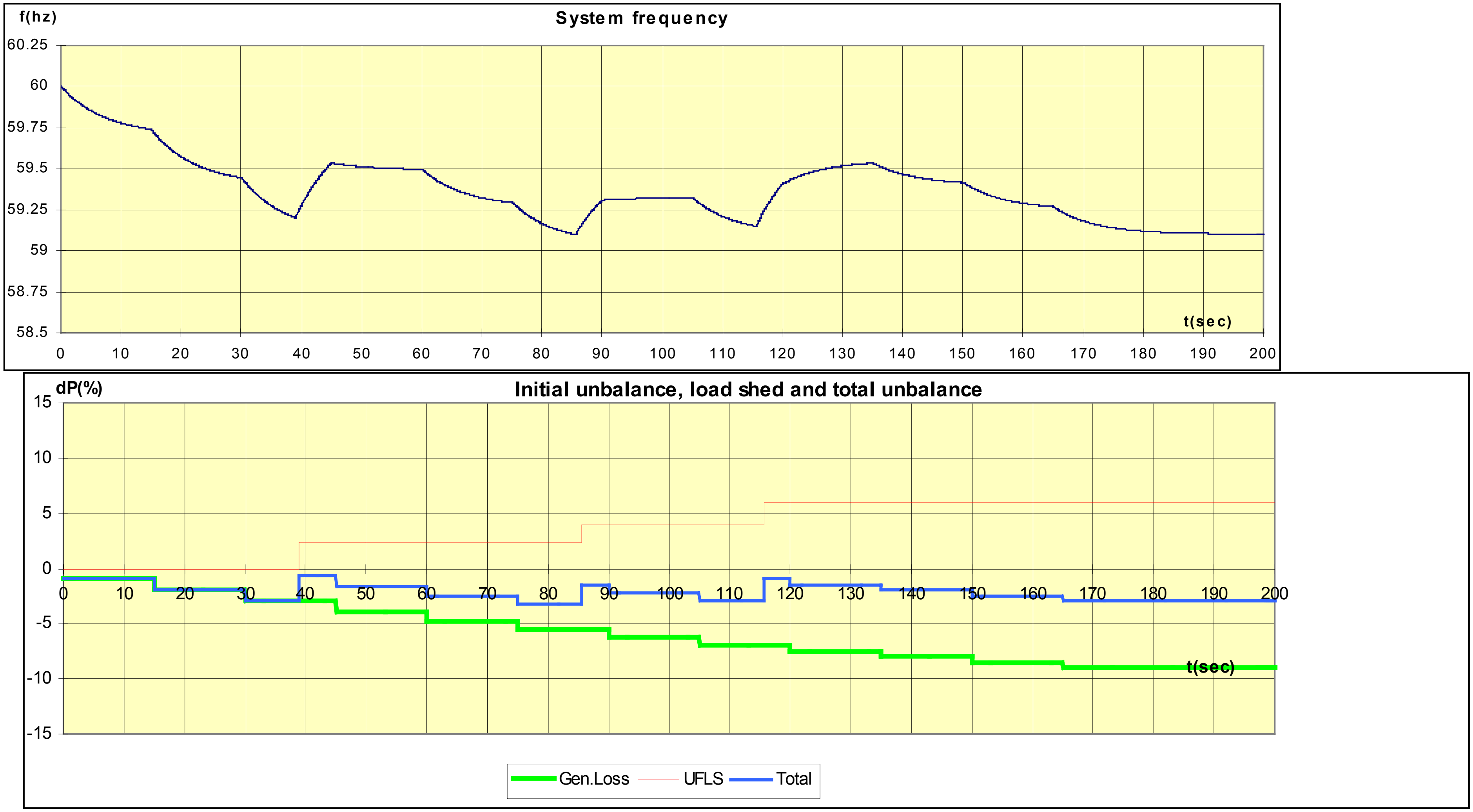
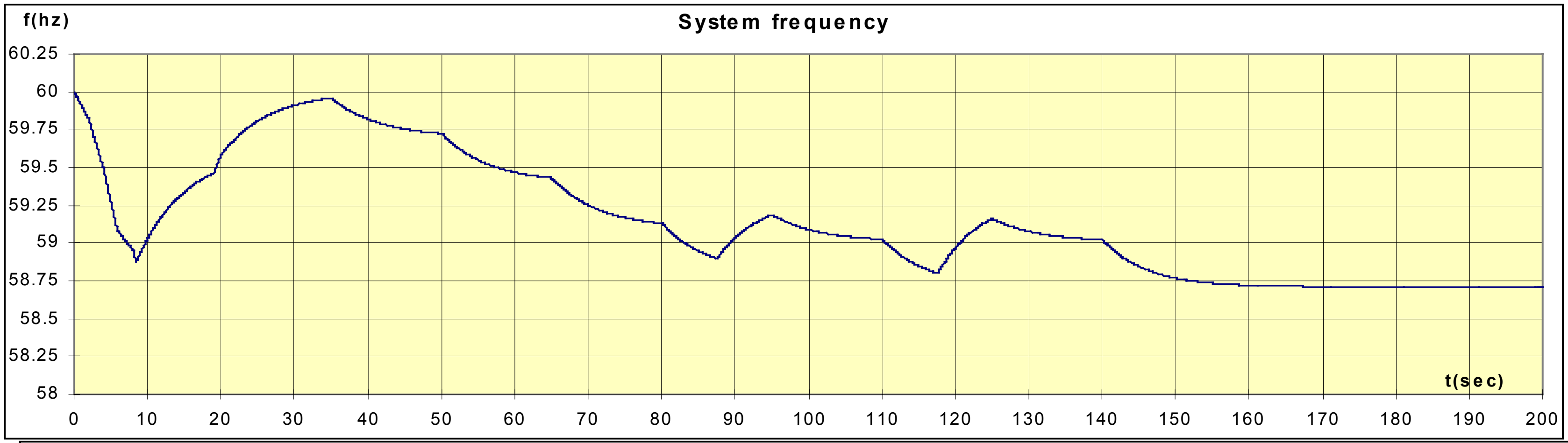


Figure 3. Gradual loss of 21.5% of generation trips 2 blocks of *UFLS-A* and 3 blocks of *UFLS-B*. Frequency stalls at 58.7 Hz.



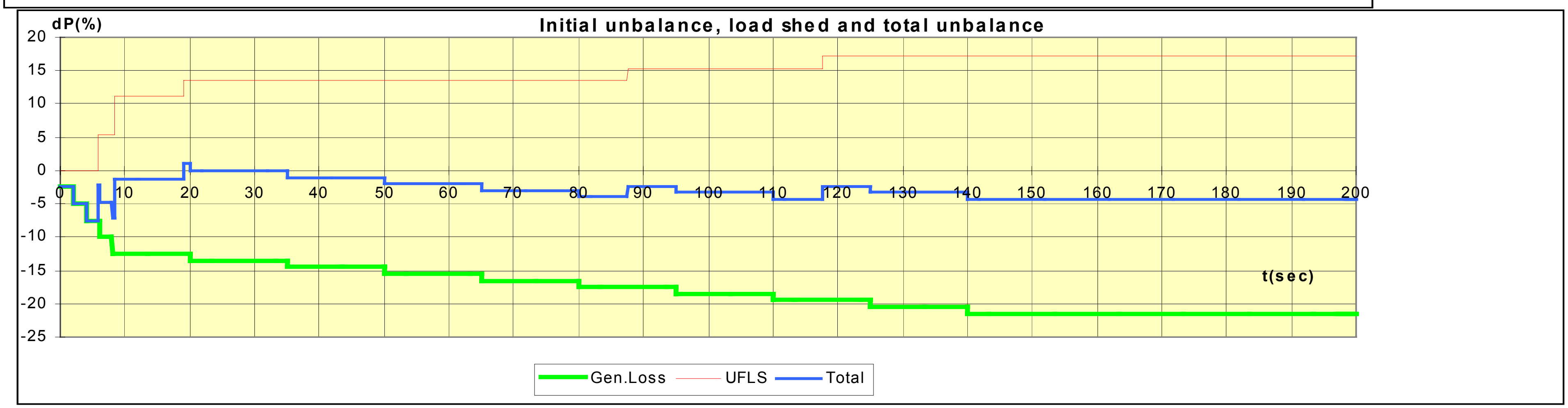


Figure 4. Gradual loss of 23.5% of generation trips interruptible customers (2%), 2 blocks of *UFLS-A* and 3 blocks of *UFLS-B*. Frequency stalls at 58.7 Hz.

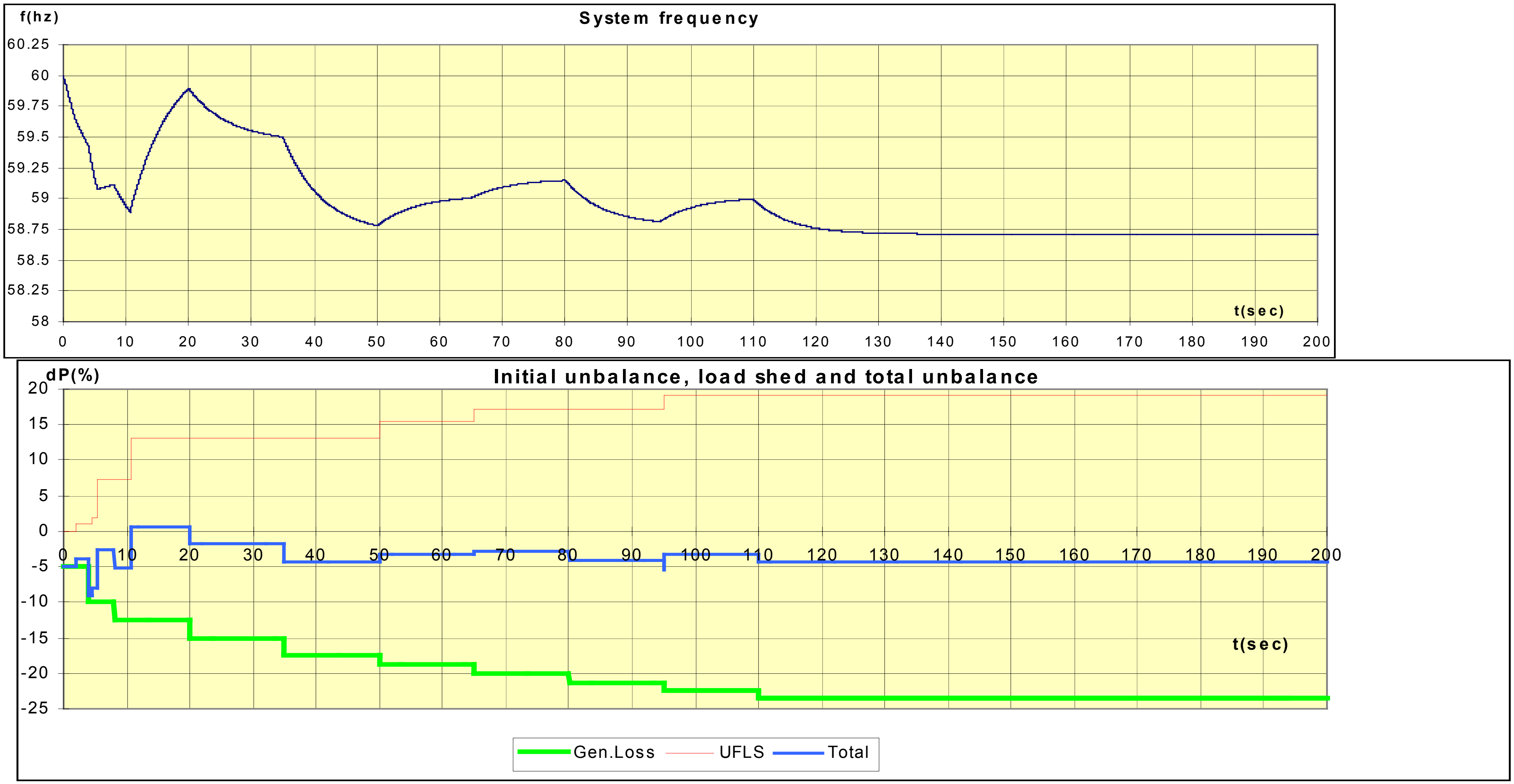


Figure 5. Existing *UFLS*. Simplified structure.

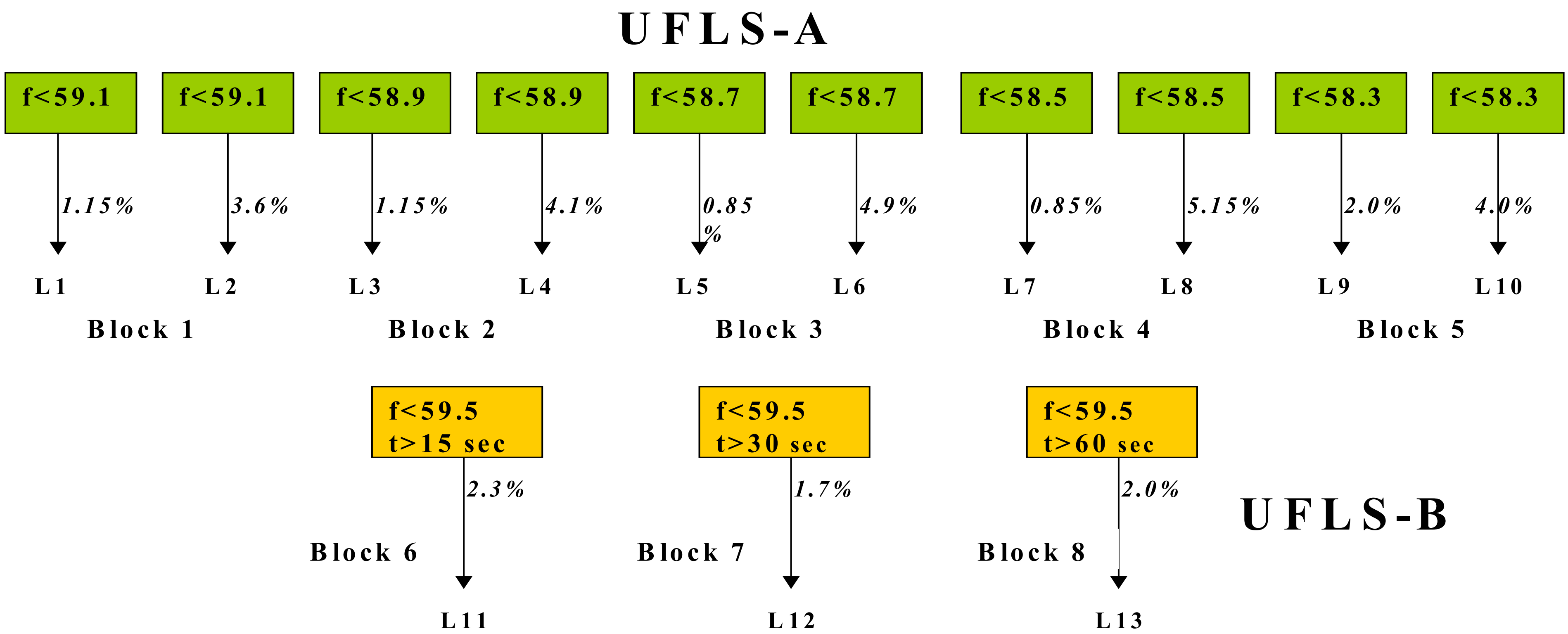


Figure 6. *UFLS-B* is increased from 20% to 40% of *UFLS-A*. 23.5% gradual loss of generation

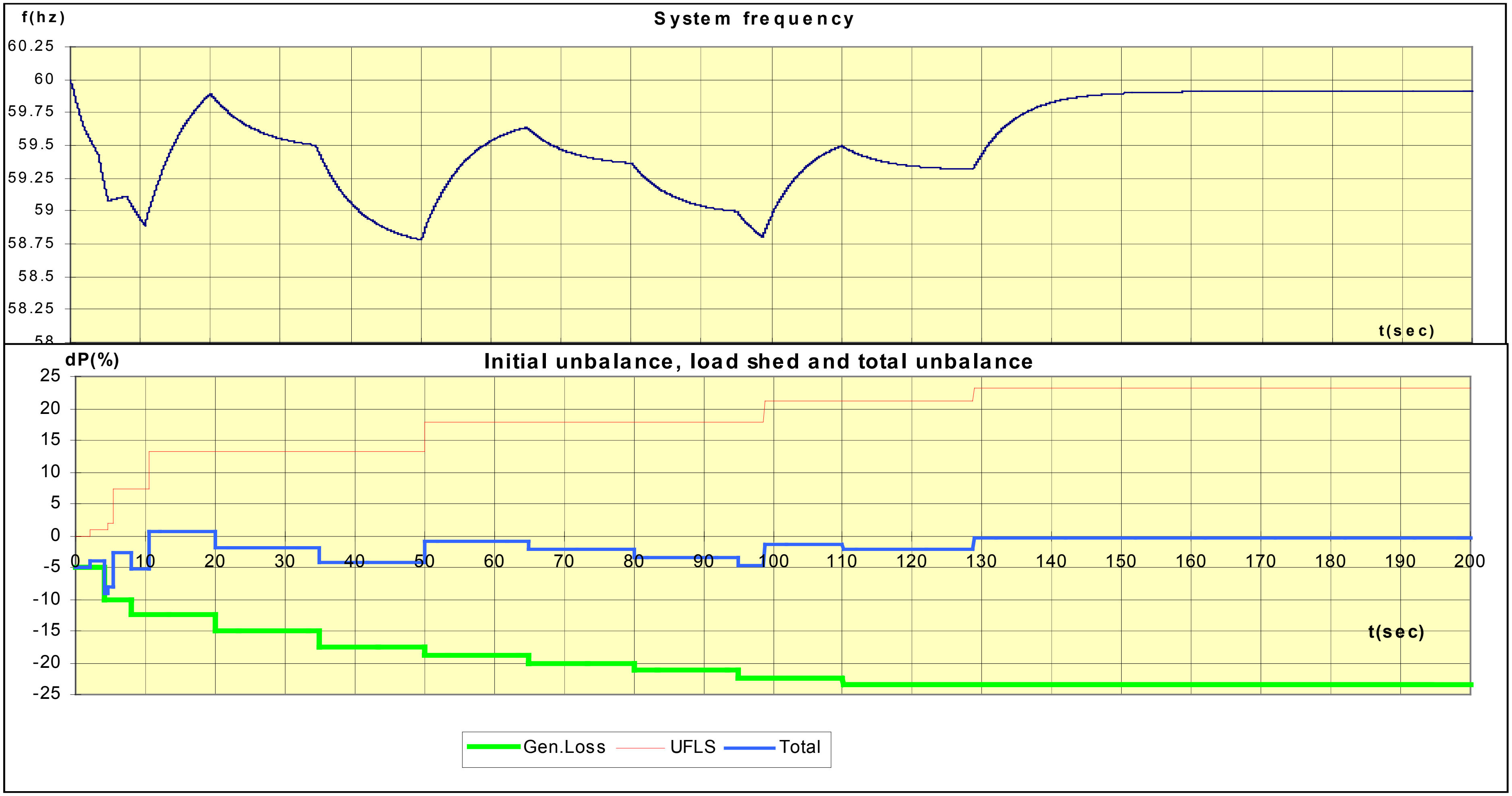


Figure 7. *UFLS* with joint trip of some loads from *UFLS-A* and *UFLS-B* (example of implementation)

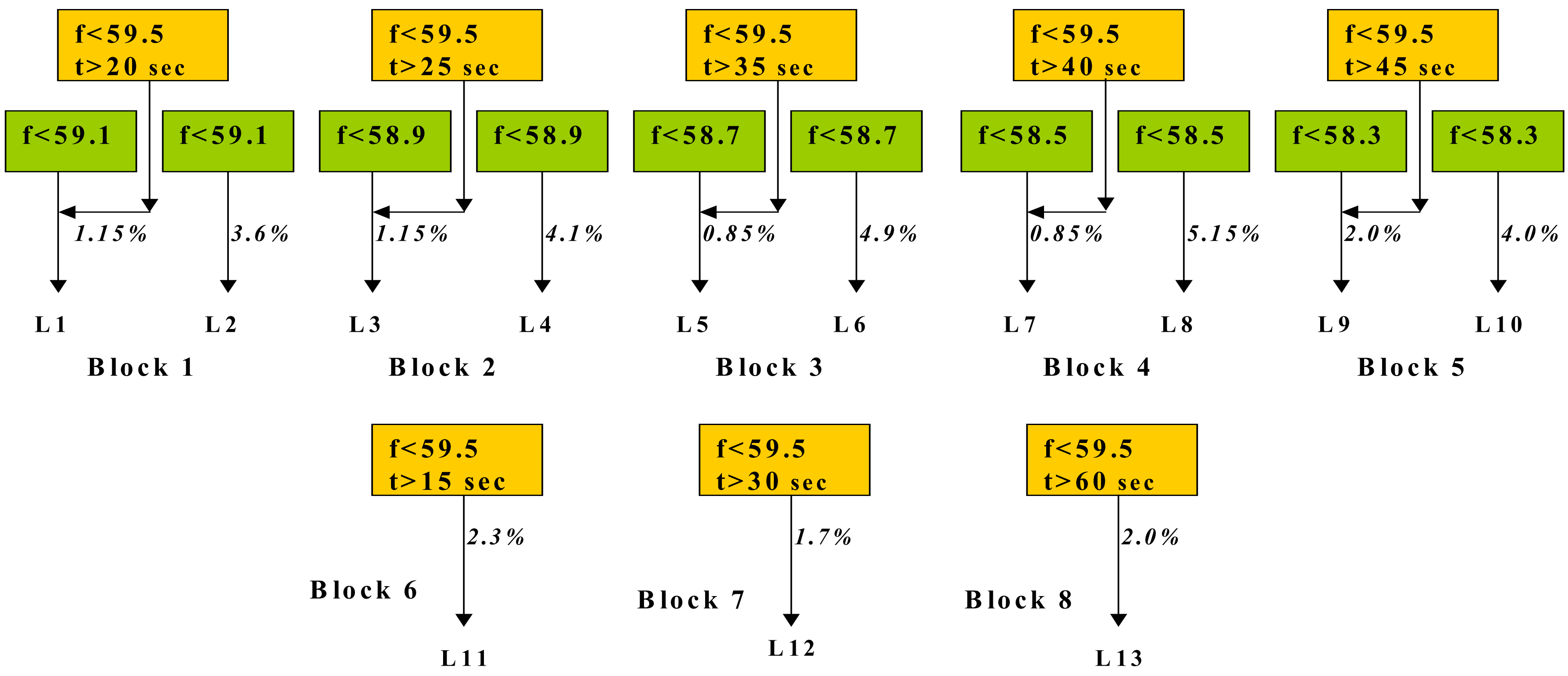


Figure 8. Gradual loss of 23.5% of generation trips interruptible customers, 2 blocks of *UFLS-A*, 3 blocks of conventional *UFLS-B* and 4 joint blocks

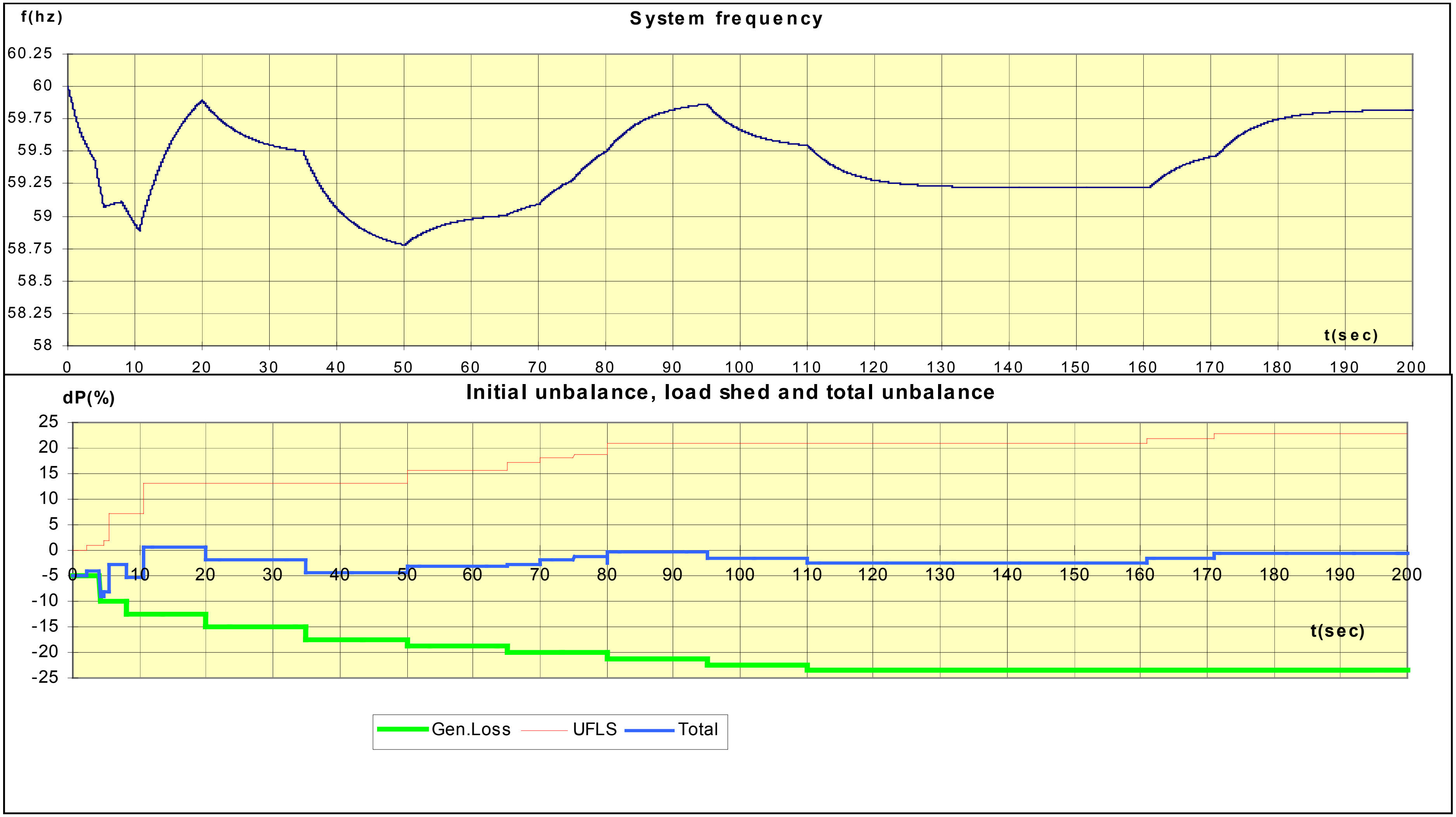
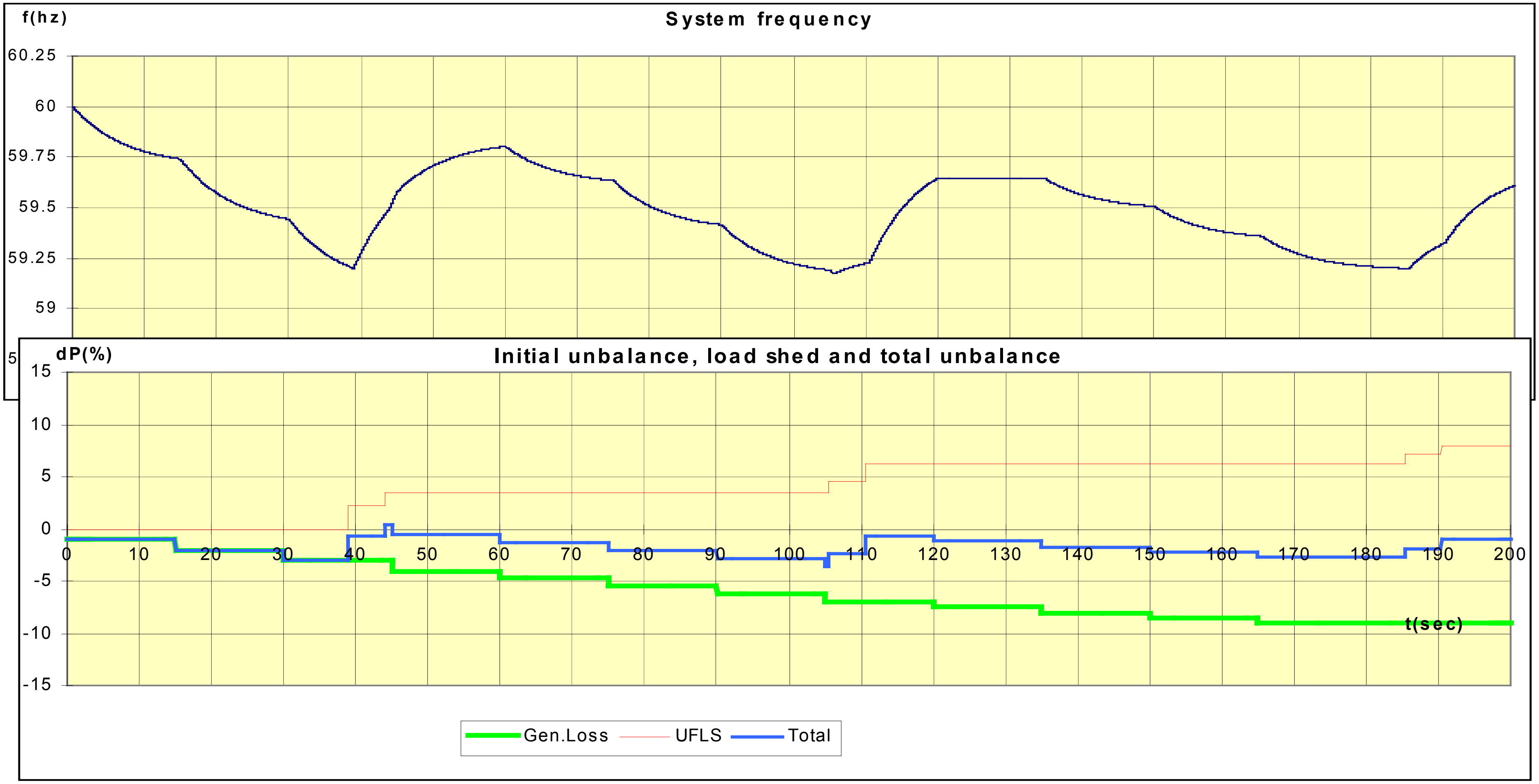


Figure 9. 9% gradual loss of generation triggers 2 blocks of conventional *UFLS-B* and 4 joint blocks



Reference C

Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Phase 2 Final Report

Evaluation Completed in December 2003

March 31, 2005

Prepared by:
Off-Nominal Frequency Work Group

Dana Cabbell (SCE, Chair)
Irina Green (CAISO)
Robert Jenkins (Mirant)
Anatoliy Meklin (PG&E)
John Phillips (Puget)
Alan Roth (Calpine)
Steve Rueckert (WECC)
John Simpson (Reliant)
Joe Tarantino (SPPC)

I. Introduction

NERC's Planning Standard III.D.S2.M4 states "Each Region shall periodically (at least every 5 years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of it Off-Nominal Frequency Plan." The WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan (WECC ONF Plan) was approved and recommended for implementation in 1997 in response to the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Electricity Coordinating Council (WECC) transmission system.

WECC initiated a review of the ONF Plan in September 2001, given that it had been five years since the implementation of WECC's ONF Plan. The Off-Nominal Frequency Work Group (ONFWG) was assigned to perform the technical analysis to determine if WECC's ONF Plan is still effective in arresting a system frequency decline due to a system-wide disturbance.

At the February 2003 PCC meeting, PCC accepted the Phase 1 Report, which determined that the 1997 WECC Coordinated Off-Nominal Frequency Plan meets the design specifications, though there may be opportunity for improvement. WECC Board approved the recommendations in the Phase 1.

PCC formed the Off-Nominal Frequency Advisory Task Force (ONFATF) to advise the TSS ONFWG on alternatives, risks, and policy issues related to the WECC ONF Plan. Upon completion of Phase 1, recommendations for further evaluation of the ONF Plan existed. The ONFATF developed six issues from these recommendations that required the ONFWG to continue its efforts into a Phase 2 of the evaluation of the WECC ONF Plan.

The following are the six issues requiring resolution in Phase 2:

- Issue #1: Re-evaluate the ONF Plan response with the new governor/load controller models
- Issue #2: Investigate increasing the instantaneous trip requirement for generators from 56.4 Hz to 57 Hz.
- Issue #3: Evaluate the results of the CMOPS' Generator Off-Nominal Frequency Survey and its impact on the ONF Plan
- Issue #4: Test an over-frequency excursion to determine what if any changes to the generator over-frequency requirement can be made
- Issue #5: Verify the base load units response in an over-frequency condition
- Issue #6: Review the automatic tie separation and load restoration requirements of the WECC ONF Plan

The six issues were addressed in Phase 2 of the Evaluation of the WECC ONF Plan. This report summarizes the technical analysis used to develop the conclusions and recommendations associated with each of the six issues.

II. Conclusions

Issue #1: Re-evaluate the ONF Plan response with the new governor/ load controller models

Conclusion 1: With the new governor and load controller models included in the testing of the ONF Plan, the frequency decline in the underfrequency simulation was effectively arrested.

Conclusion 2: The simulated frequency recovery with the new governor and load controller models was slower than for the simulation without the new models. The frequency appeared to settle at 59.125 Hz.

Conclusion 3: To achieve a frequency recovery, two of the anti-stall load shedding blocks were simulated at 59.5 Hz and 59.3 Hz. This action resulted in the system frequency to settle at 59.6 Hz.

Conclusion 4: The Off-Nominal Plan should be evaluated for the gradual generation loss scenarios. The August 14, 2003 blackout has proven that this is the most likely scenario for UFLS operation.

Issue #2: Investigate increasing the instantaneous trip requirement for generators from 56.4 Hz to 57 Hz.

Conclusion 5: From the underfrequency simulation with the new governor and load controller models, the lowest frequency simulated was 57.7 Hz.

Conclusion 6: From past WECC Disturbance Reports, the lowest frequencies recorded were during the December 22, 1982 disturbance at 57.6 HZ and during the August 10, 1996 disturbance at 58.3 Hz.

Conclusion 7: A comparison of other NERC Regional Councils off-nominal frequency programs showed the typical frequency generators are allowed to trip instantaneously was 57 Hz to less than 58.2 Hz.

Conclusion 8: The original Plan was designed to prevent frequency declines lower than 57.9 Hz. This provided the 1.5 Hz margin to the “5% loss of life” limitation, which was considered equal to 56.4 Hz. This means that the change of the limitation from 56.4 to 57 Hz does not make the Plan insufficient but just reduces the margin from 1.5 Hz to 0.7 Hz.

Issue #3: Evaluate the results for CMOPS' Generator Off-Nominal Frequency Survey and its impact on the ONF Plan

Conclusion 9: A WECC Staff Report, dated April 28, 2003 summarized the response to the CMOPS Generator Off-Nominal Frequency Survey. Out of the 72 responses, WECC Staff received as of April 25, 2003, 49 respondents indicated ownership of generation. Of those, 22 responses that indicated all generators complied with the ONF Plan's generator requirements and 27 indicated that one or more generators do not meet all the provisions of the ONF Plan.

Conclusion 10: The MW amount of the non-compliant generators totaled 13,160 MW for 37 units.

Issue #4: Test an over-frequency excursion to determine what if any changes to the generator over-frequency requirement can be made

Conclusion 11: A simulated over-frequency condition was created through tripping large blocks of load throughout the WECC system. The load was dropped in five percent increments starting at 10% and ending at 25%. The resulting highest frequency ranged from 60.54 Hz up to 61.42 Hz.

Conclusion 12: The simulated Overfrequency did not reduce to the 60.6 Hz continuous operation level due to the load controller models. Completing the over-frequency evaluation will be delayed until an evaluation of the operation of load controllers is performed.

Issue #5: Verify the base load units response in an over-frequency condition

Conclusion 13: The models of the generator units are working correctly within the simulation, however, the overall governor response in an off-nominal frequency situation is counter to the response is expected in a frequency excursion from a reliability standpoint.

Issue #6: Review the automatic tie separation and load restoration requirements of the WECC ONF Plan

Conclusion 14: This issue was not completed during this Phase 2 evaluation and will need to be held over to Phase 3 of the evaluation of the ONF Plan.

Gradual Loss of Generation Discussion -- Carry over from Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan Report, dated 1/21/03

This UFLS structure could be less effective for a more common gradual loss of generation. The analysis of UFLS performance on a gradual loss of generation is presented in the *Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan Report*, dated 1/21/03
.
The main conclusions of this analysis are:

1. A part or all of UFLS-A blocks may not participate in balancing a gradual generation loss because the leading UFLS-B actions prevent deep frequency declines.

2. When some UFLS-A blocks do not participate, 6% of system load connected to UFLS-B (20% of UFLS-A) is not enough to prevent frequency stalling at 58.7 Hz or even lower.

3. The possible solution, preventing frequency stalling, is implementation of additional UFLS-B circuits for the trip of some loads, presently connected to UFLS-A.

4. The Task Force agreed that adjusting the existing program to capture the impact of a gradual generation loss is a long-term betterment of the UFLS Program

5. If an area sees the potential of gradual generation loss, they should investigate changing their area program.

6. If an area is concerned with gradual generation loss, when entities within the area are changing relays, add ones that have many outputs to implement such a adjustment to the program.

III. Recommendations

Recommendation 1: Revise the instantaneous underfrequency generator trip setting in the WECC ONF Plan to 57 Hz from the present 56.4 Hz.

Under-frequency Limit	Over-frequency Limit	WECC Minimum Time
> 59.4 Hz	60 Hz to < 60.6 Hz	N/A (continuous operation)
≤ 59.4 Hz	≥60.6 Hz	3 minutes
≤ 58.4 Hz	≥61.6 Hz	30 seconds
≤ 57.8 Hz	-	7.5 seconds
≤ 57.3 Hz	-	45 cycles
≤ 57 Hz	>61.7 Hz	Instantaneous trip

Recommendation 2: Resolve the following remaining issues in Phase 3:

Action 1: Load Controller on Generators

- Evaluate the delay operation of the load controller during frequency excursions
- Identify what polices, modeling, EMS performance, and any other factors contributing to adverse system performance during the operation of the Off-Nominal Plan

Action 2: Review and verify whether Figure 6 of the ANSI/IEEE C37.106-1987 reflects the worst case composite curve for generator operation during frequency excursions

Action 3: Evaluate the impact of the non-compliant generator units on the WECC Off-Nominal Frequency Plan

Action 4: Evaluate an over-frequency excursion to determine what if any changes to the generator over-frequency requirements should be recommended

Action 5: Evaluate the automatic tie separation and load restoration requirements

Action 6: Develop a single technical support document to provide the back-up documentation for the current WECC Off-Nominal Frequency Plan.

IV. Discussion

Issue #1: Re-evaluate the ONF Plan response with the new governor/ load controller models

The re-evaluation of the ONF Plan to determine the impact due to the new governor and load controller models repeated the islanding study as described in 2003 Evaluation of the WECC Coordinated Off-Nominal Frequency Program (Phase 1 Report).

The test was performed for the southern island scenario only. It was concluded the northern island scenario did not need to be simulated based on the results from the Phase 1 simulation of the southern and northern islands. The system response in both islands was similar during the simulated frequency excursion.

Using the new governor model (ggov1) and turbine load control model (lcfb1), an instantaneous 30% loss of resources was simulated in the southern island, which was formed due to loss of COI and the operation of the Northeast/Southeast Separation Scheme (Southern Island Study). Underfrequency trips of the non-compliant units were not simulated. The impact of the non-compliant units pertains to Issue #3.

Figure 1 shows a comparison of the underfrequency system response between using the old governor model, and the new ggov1, and lcfb1 models. The frequency decline in the underfrequency simulation was effectively arrested. However, the simulated frequency recovery with the new governor and load controller models was slower than for the simulation without the new models. The frequency for the simulation with the new models appears to settle at 59.125 Hz.

To determine where the frequency settles, the simulation with the new models was extended for 45 seconds. As shown in Figure 2, the frequency settles at 59.6 Hz, only after initiating two of the three anti-stall load shedding blocks.

The reason for the slower response is concluded to be due to the load controller model (lcfb1) that has been added to the dynamic data for steam generators simulated. This is further investigated in the discussion below for Issue #5.

Issue #2: Investigate increasing the instantaneous trip requirement for generators from 56.4 Hz to 57 Hz.

The ONFWG has developed a recommendation to adjust the frequency level at which a generator is allowed to instantaneously trip during an under-frequency excursion. The change is to increase this frequency level from 56.4 Hz to 57 Hz. Using the UFLS simulation with the new ggov1 and load controller models, and historical disturbance data, the ONFWG investigated increasing the instantaneous trip to 57 Hz from 56.4 Hz.

The lowest frequency dip for the UFLS simulation with the new ggov1 and load controller models was 57.7 Hz. Information from WECC disturbance reports showed the lowest frequency recorded occurred during the 12/22/82 disturbances at a level of 57.6 Hz.

The longest duration to get back to normal frequency was 2.5 hours and occurred during the August 1996 disturbance. During this disturbance, frequency bounced from an initial dip of 58.54 Hz and spiked to 60.7 Hz, then dipped to 58.3 Hz.

A search was made of other NERC Regional Council's websites to gather information on their off-nominal frequency programs, and particularly at what frequency point are generators allowed to instantaneously trip during underfrequency excursions. Table 1 below summarizes the results of the investigation.

Table 1: Comparison among NERC Regional Councils of Frequency Level for Allowed Generator Instantaneous Trip

Council	Freq. Generator Allowed to Trip
NPCC	57 Hz
ERCOT	57.5 Hz
MAAC	<57.5 Hz
ECAR	<58.2 Hz
FRCC	<57.5 Hz
WECC	56.4 Hz

The comparison in Table 1 of other NERC Regional Councils off-nominal frequency programs showed the typical frequency generators are allowed to trip instantaneously was 57 Hz to less than 58.2 Hz.

The following summarizes the conclusions of the ONFWG's investigation:

1. The studies performed by the ONFWG show a minimum frequency of 57.5 Hz;
2. The lowest frequency from past WECC disturbances was 57.6 Hz;
3. Other NERC Regions have a range of 57 to 57.5 Hz as their instantaneous trip point
4. 57 Hz provides an engineering margin

5. WECC's original Plan was designed to prevent frequency declines lower than 57.9 Hz. This provided the 1.5 Hz margin to the "5% loss of life" limitation, which was considered equal to 56.4 Hz. This means that the change of the limitation from 56.4 to 57 Hz does not make the Plan insufficient but just reduces the margin from 1.5 Hz to 0.7 Hz.

Based on the above conclusions, the ONFWG recommends increasing the instantaneous trip for generators to 57 Hz from 56.4 Hz.

Table 2 below illustrates the revised relay protection requirement for off-nominal frequency generator performance.

Table 2: Off-Nominal Frequency Generator Operation Requirement

Under-frequency Limit	Over-frequency Limit	Minimum Time
> 59.4 Hz	60 Hz to < 60.6 Hz	N/A (continuous operation)
≤ 59.4 Hz	≥60.6 Hz	3 minutes
≤ 58.4 Hz	≥61.6 Hz	30 seconds
≤ 57.8 Hz		7.5 seconds
≤ 57.3 Hz		45 cycles
≤ 57 Hz	>61.7 Hz	Instantaneous trip

Issue #3: Evaluate the results for CMOPS' Generator Off-Nominal Frequency Survey and its impact on the ONF Plan

A WECC Staff Report, dated April 28, 2003 summarized the response to the CMOPS Generator Off-Nominal Frequency Survey. Out of the 72 responses, WECC Staff received as of April 25, 2003, 49 respondents indicated ownership of generation. Of those, 22 responses that indicated all generators complied with the ONF Plan's generator requirements and 27 indicated that one or more generators do not meet all the provisions of the ONF Plan.

The MW amount of the non-compliant generators and their location was determined through the survey responses and are summarized in Table 3.

Table 3: Results of CMOPS' Generator Off-Nominal Frequency Survey

Region	MW	Over frequency Settings (Hz)	Under frequency Settings (Hz)
NWPP	5,100	60.6 to 61.2	56.9 to 59.4 33 units > 57 Hz 4,800 MW
RMPA	4,880	61.0 to 61.5	56.9 to 58.4 7 units > 57 Hz 3,900 MW
AZ/NM/SNV	7,630	N/A	57.0 to 58.5 15 units > 57 Hz 2,990 MW
CA/MX	1,760	60.5 to 61	57.0 to 59.1 12 units > 57 Hz 1,470 MW
Total	19,370		37 units > 57 Hz 13,160 MW

The Planning Coordination Committee's Steering Committee requested the ONFWG to evaluate the system reliability impact of the non-compliant generators. This technical study was not completed in this phase of the ONFWG's work. The evaluation of the non-compliant units will be performed in Phase 3.

Issue #4: Test an over-frequency excursion to determine what if any changes to the generator over-frequency requirement can be made

The ONFWG was directed to test the over-frequency generator requirements. A concern arose regarding new combine cycle generators not meeting the over-frequency relay setting requirements stated in the WECC ONF Plan.

To test the over-frequency requirements, a simulation of an over-frequency event was required. An over-frequency condition was created through tripping large blocks of load throughout the WECC system. The load was dropped in five percent increments starting at 10% and ending at 25%. The objective for this exercise was to see whether the governors bring the frequency back down faster than the relays would trip generation.

Table 4: Over-Frequency Test Results

		Highest Frequencies			
Bus	kV	10% Load Drop	15% Load Drop	20% Load Drop	25% Load Drop
ING500	500	60.524	60.718	61.041	61.402
BRIDGER	345	60.513	60.703	61.008	61.357
MIDPOINT	500	60.513	60.701	61.007	61.349
COLSTRP	500	60.516	60.712	61.020	61.362
MALIN	500	60.514	60.705	61.010	61.349
KYRENE	500	60.543	60.728	61.055	61.416
WESTMESA	345	**60.544**	**60.731**	**61.058**	**61.418**
CAMP WIL	345	60.521	60.709	61.026	61.375
TESLA	500	60.514	60.701	61.004	61.355
PAWNEE	230	60.536	60.726	61.035	61.388
LUGO	230	60.534	60.713	61.033	61.387
Ten Highest Frequencies		**60.625**	**60.804**	**61.430**	**61.573**
		60.622	60.799	61.346	61.569
		60.604	60.782	61.237	61.548
		60.585	60.781	61.206	61.516
		60.583	60.781	61.191	61.516
		60.581	60.780	61.191	61.515
		60.581	60.780	61.177	61.512
		60.580	60.779	61.160	61.511
		60.580	60.779	61.159	61.509
		60.580	60.778	61.158	61.508

Over-freq. Limit	Minimum Time
60.0-< 60.6 Hz	N/A (continuous operation)
60.6-<61.6 Hz	3 minutes
61.6-<61.7 Hz	30 seconds
	7.5 seconds
	45 cycles
	7.2 cycles
> 61.7 Hz	Instantaneous trip

As summarized in Table 4, the simulated over-frequency condition did not reduce to the 60.6 Hz continuous operation level. Figure 3 and 4 are frequency plot for the 10% and 15% loss of load scenario. ONFWG concluded the reason for the non-responsiveness of the governors was due to the load controller models. The completion of the over-frequency evaluation will be delayed until an evaluation of the operation of load controllers is performed, which is described below in Issue #5's discussion.

Issue #5: Verify the base load units respond in an over-frequency condition

ONFWG was asked to verify that the response of the base load generating units in an over-frequency condition correctly matches the actual response of a base load unit. ONFWG simulated both over and under frequency conditions to test the governor action if the unit is base load and/or has a load controller.

Table 5 captures the conclusion to this analysis. The models of the generator units are working correctly within the simulation, however, the overall governor response in an off-nominal frequency situation is counter to the response is expected in a frequency excursion from a reliability standpoint. For example, in an over-frequency condition, the governor started to reduce the units output, but the load controller brought the unit output back up to the unit's original value. Figures 5 thru 12 are the frequency plots for the analysis summarized in Table 5.

Table 5: Effect of Base Load Flag and Load Controllers on Unit Response for Frequency Excursions

		Unit Response if	
Base Load Flag	**Load Controller***	**Frequency Falls**	**Frequency Increases**
0	no	If not already at maximum output, unit responds with additional mechanical power per governor data.	Unit backs down per governor data.
0	yes	If not already at maximum output, unit initially responds with additional mechanical power per governor data. Load control attempts to bring unit output back down to original value.	Unit initially backs down per governor data. **Load controller attempts to bring unit output back up to original value.**
1	no	Unit can not repsond with additional mechanical power. Base Load Flag being set results in PMAX of governor being set to PGEN of machine during initialization of dynamics data.	Base Load Flag being set has no impact on unit response. Unit backs down per governor data.
1	yes	Unit can not repsond with additional mechanical power. Base Load Flag being set results in PMAX of governor being set to PGEN of machine during initialization of dynamics data.	Base Load Flag being set has no impact on unit response. Unit initially backs down per governor data. **Load controller attempts to bring unit output back up to original value.**

* Load Controller includes GGOV1 governor model with kimw non-zero and LCFB1 Load Controller with gain (KI) >0 for other governor models.

The ONFWG also considered looking at the minimum time delays associated with the off-nominal frequency settings for generators. However, with the delayed recovery that the ONFWG studies have shown with the new governor models, changing these delay times would be pre-mature. WECC first needs to address what we are going to do concerning the combined impact of the non-compliant generators that trip at too high a frequency and the overall poor governor response due to blocked governors/load controllers, before any action is taken with respect to the under-frequency generator time delays.

The delay operation of the load controllers will be addressed in Phase 3 of ONFWG's ongoing investigation of the WECC ONF Plan.

Issue #6: Review the automatic tie separation and load restoration requirements of the WECC ONF Plan

TSS was directed to consider whether the automatic tie separation language in the WECC ONF Plan should be strengthened. Apparently, some members are setting tie-line relay to open before the required 57.9 Hz. TSS was also directed to review the automatic load restoration requirements in the WECC ONF Plan. Some systems cannot restore load automatically for certain levels of frequency over-shoot. The two questions posed to ONFWG were: 1) should automatic load restoration continue to be a requirement, or can we rely on governor action, and 2) at what frequency does automatic restoration not need to be discouraged?

ONFWG focused on Issues #1-5 during phase 2 and hasn't started to investigate the questions regarding automatic tie separation and load restoration requirements of the WECC ONF Plan. This will be carried over to Phase 3.

V. Next Steps

Recommend to PCC the adjustment to the generator underfrequency instantaneous trip setting to 57 Hz and the need to complete the following evaluations in Phase 3:

- UFLS response with the new governor/load controller models
- Use actual UFLS data records
- Test adjustments to UFLS anti-stall requirements
- Test the impact of the non-compliant units
- System test of an over-frequency excursion to determine what if any changes to the generator over frequency requirements can be made
- Automatic Tie Separation requirements
- Load Restoration requirements

VI. Further Study

The ONFWG will continue its work in Phase 3 to resolve the following six action items remaining from or added during Phase 2:

Action 1: Load Controller on Generators

– Evaluate the delay operation of the load controller during frequency excursions

– Identify what polices, modeling, EMS performance, and any other factors contributing to adverse system performance during the operation of the Off-Nominal Plan

Action 2: Review and verify whether Figure 6 of the ANSI/IEEE C37.106-1987 reflects the worst case composite curve for generator operation during frequency excursions

Action 3: Evaluate the impact of the non-compliant generator units on the WECC Off-Nominal Frequency Plan

Action 4: Evaluate an over-frequency excursion to determine what if any changes to the generator over-frequency requirements should be recommended

Action 5: Evaluate the automatic tie separation and load restoration requirements

Action 6: Develop a single technical support document to provide the back-up documentation for the current WECC Off-Nominal Frequency Plan

Phase 3 is scheduled to be completed by October 2004.

Figure 1
UFLS Response Comparison between Old Governor Data and New GGOV1/lcfb1 Model Data

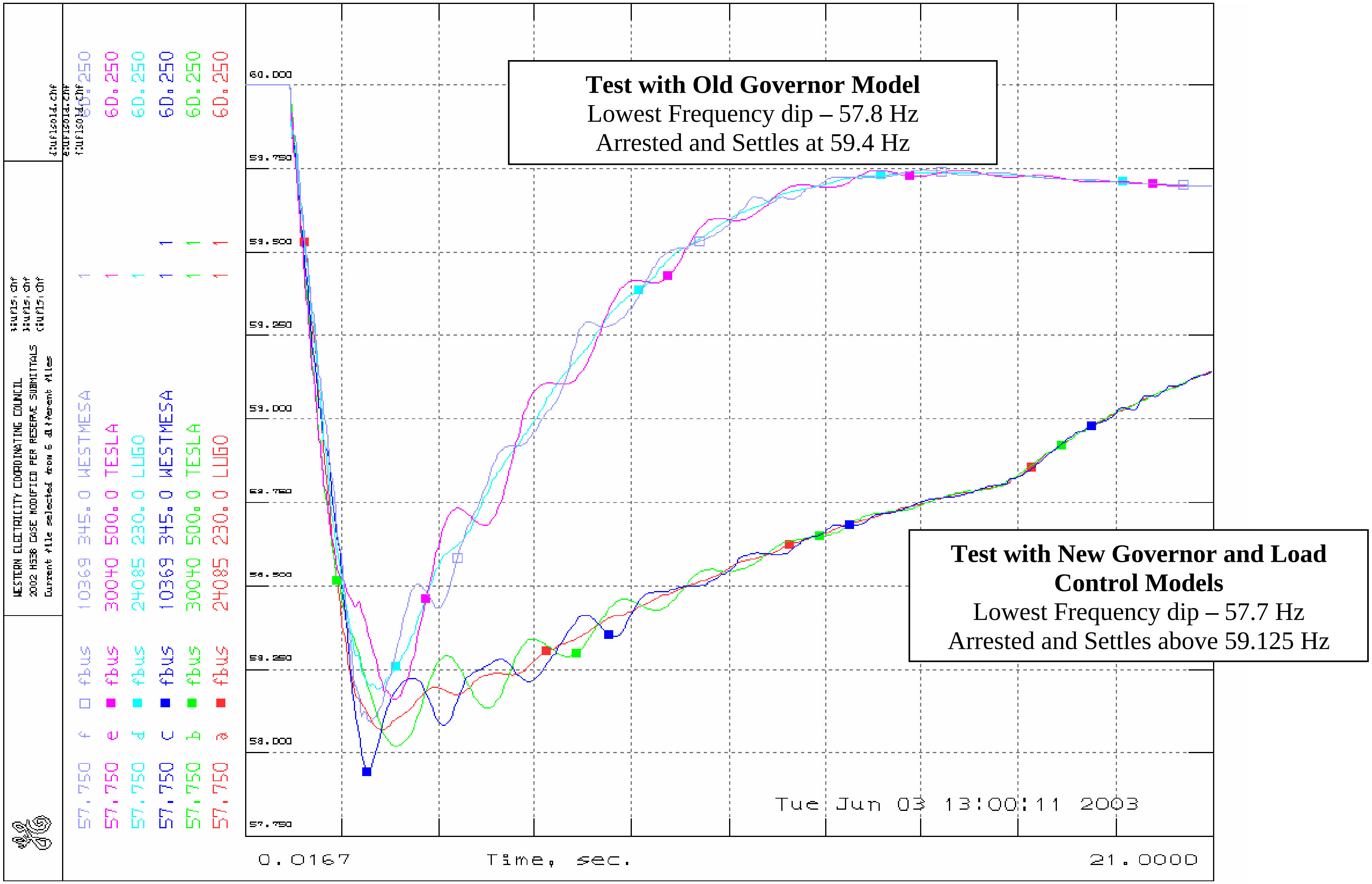


Figure 2
UFLS Response with New GGOV1/lcfb1 Models during a 45 sec Simulation

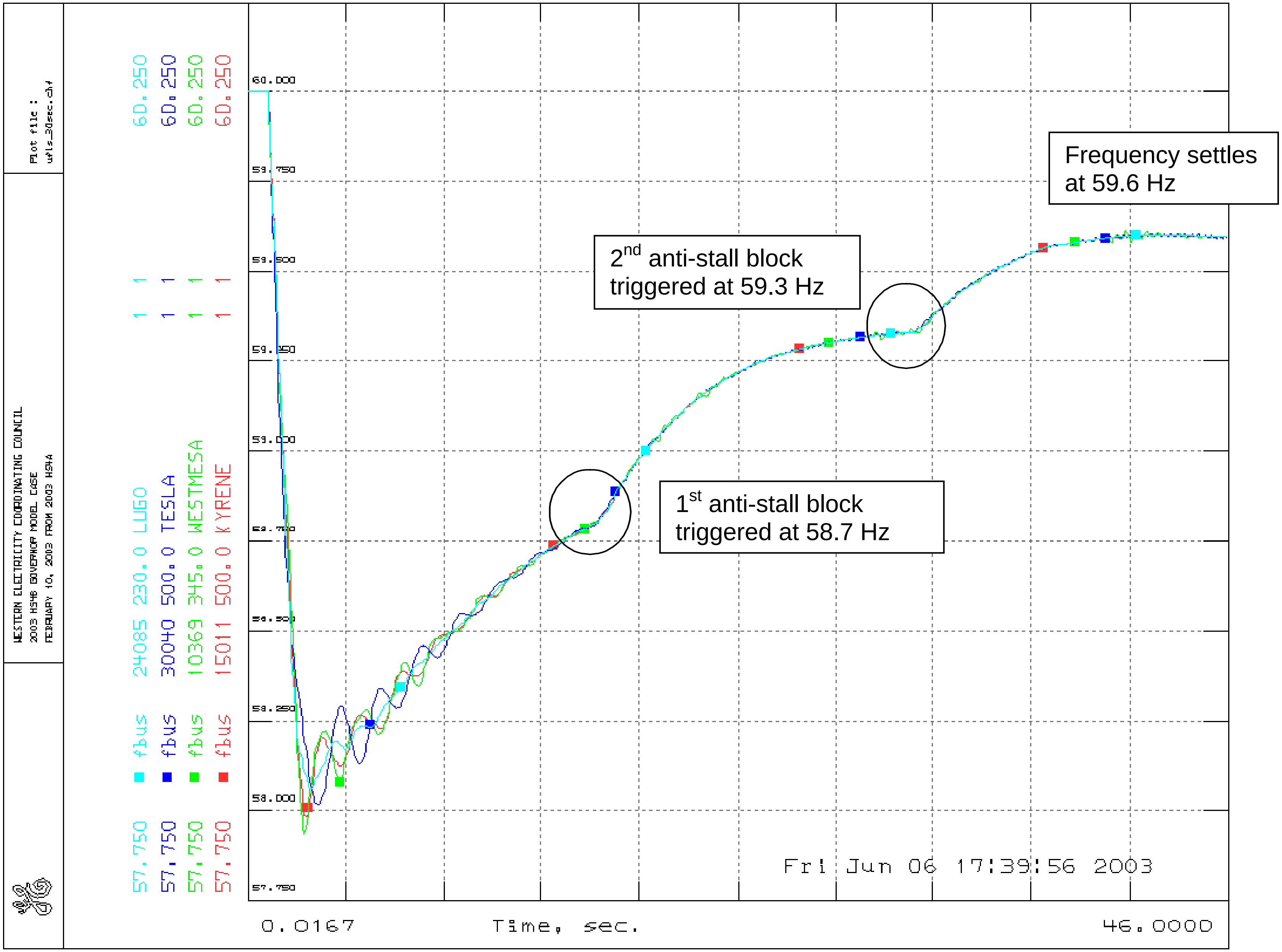


Figure 3
Over-frequency Test with 10% loss of load

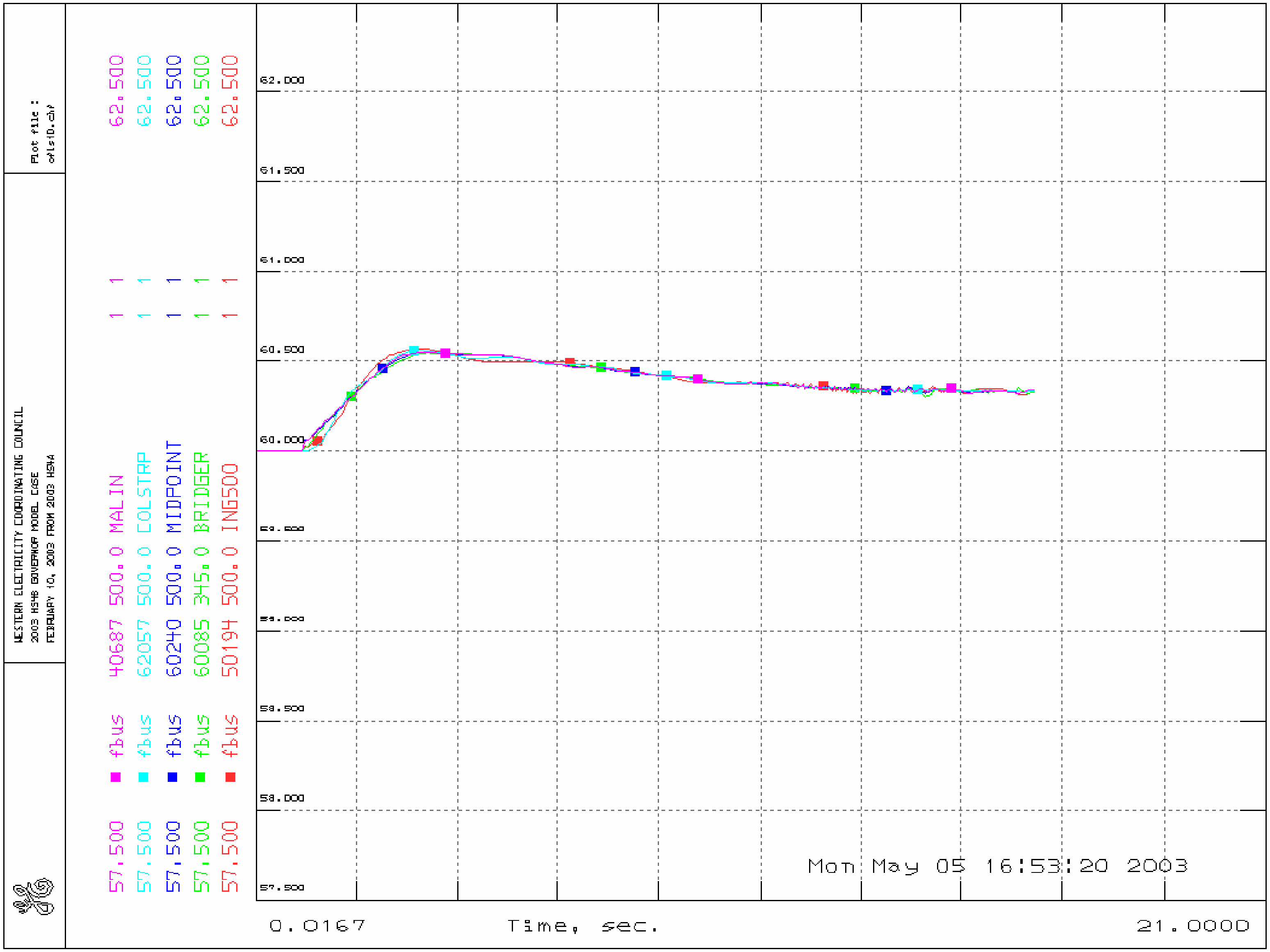


Figure 4
Over-Frequency Test with 15% Loss of Load

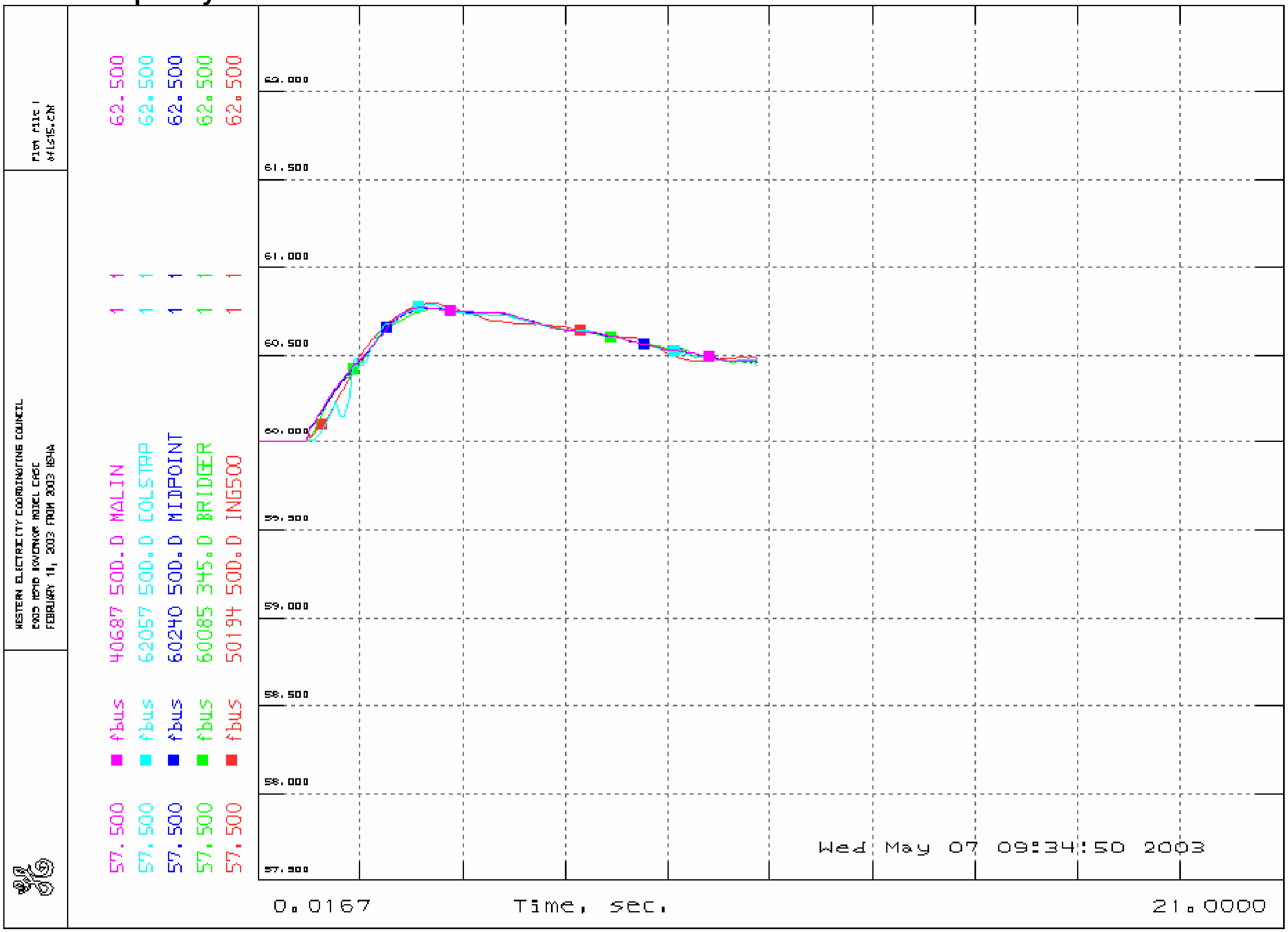


Figure 5
Response for Underfrequency
Base Load Flag =0   No Load Controller Modeled

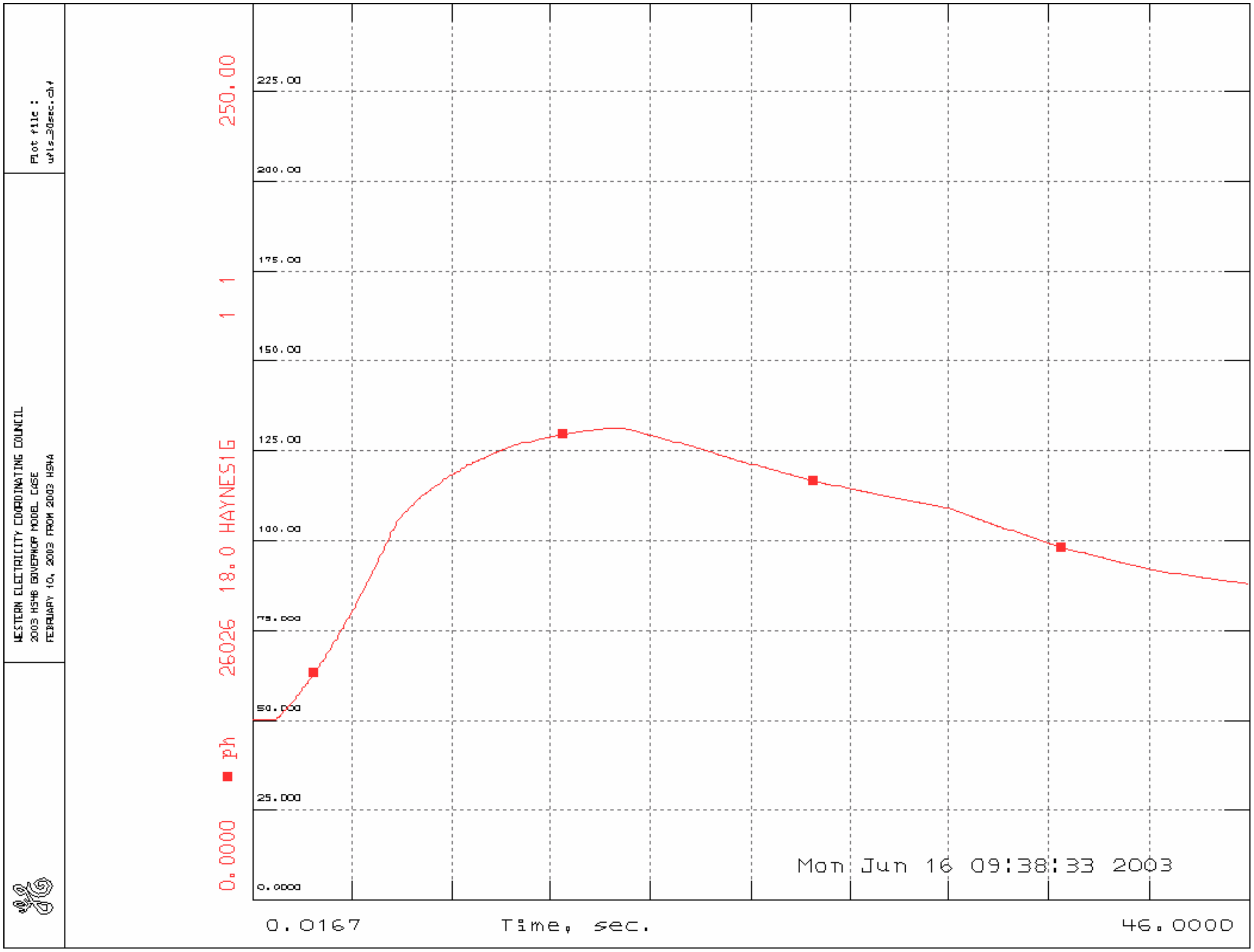


Figure 6
Response for Overfrequency
Base Load Flag =0   No Load Controller Modeled

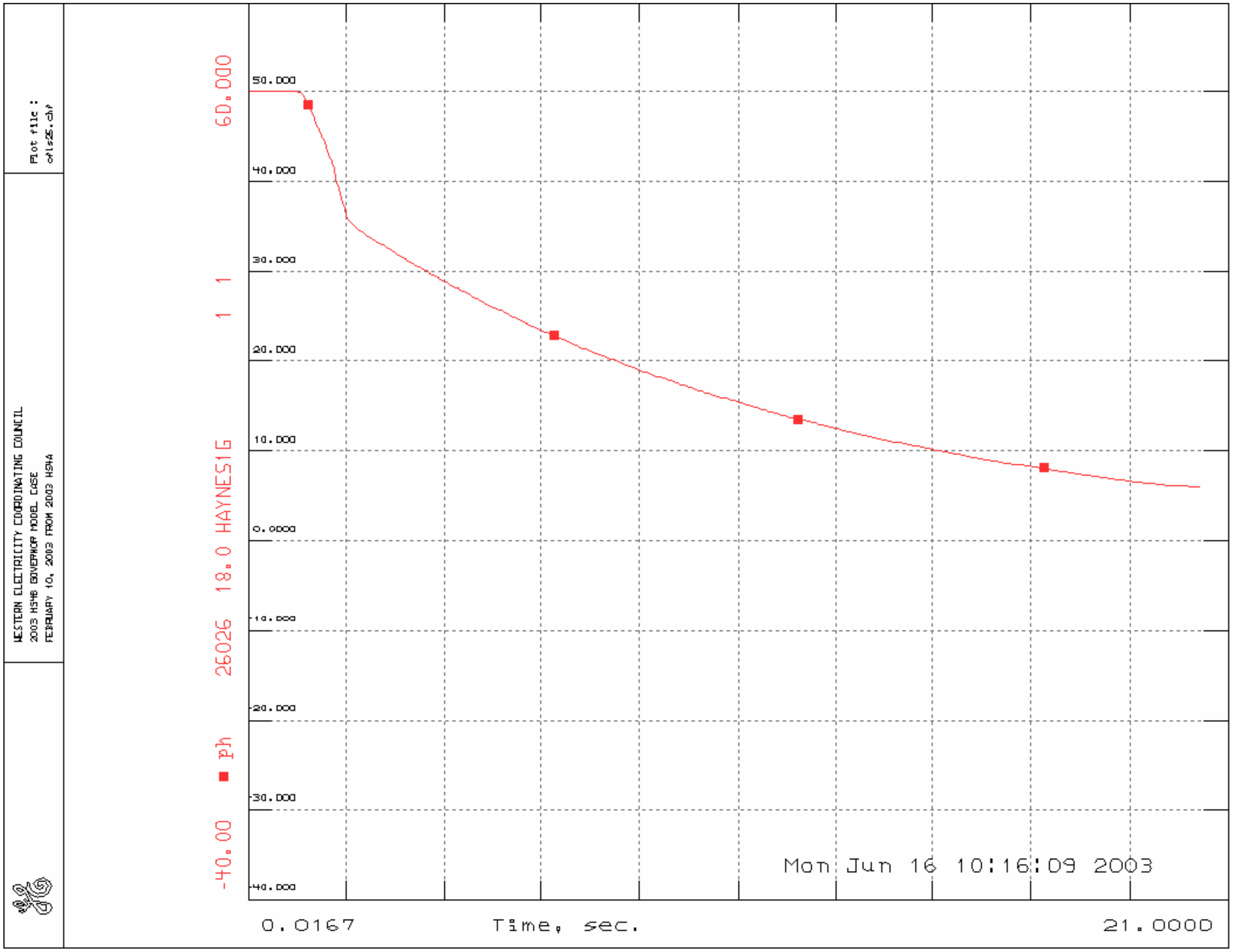


Figure 7
Response for Underfrequency
Base Load Flag =0   Load Controller Modeled

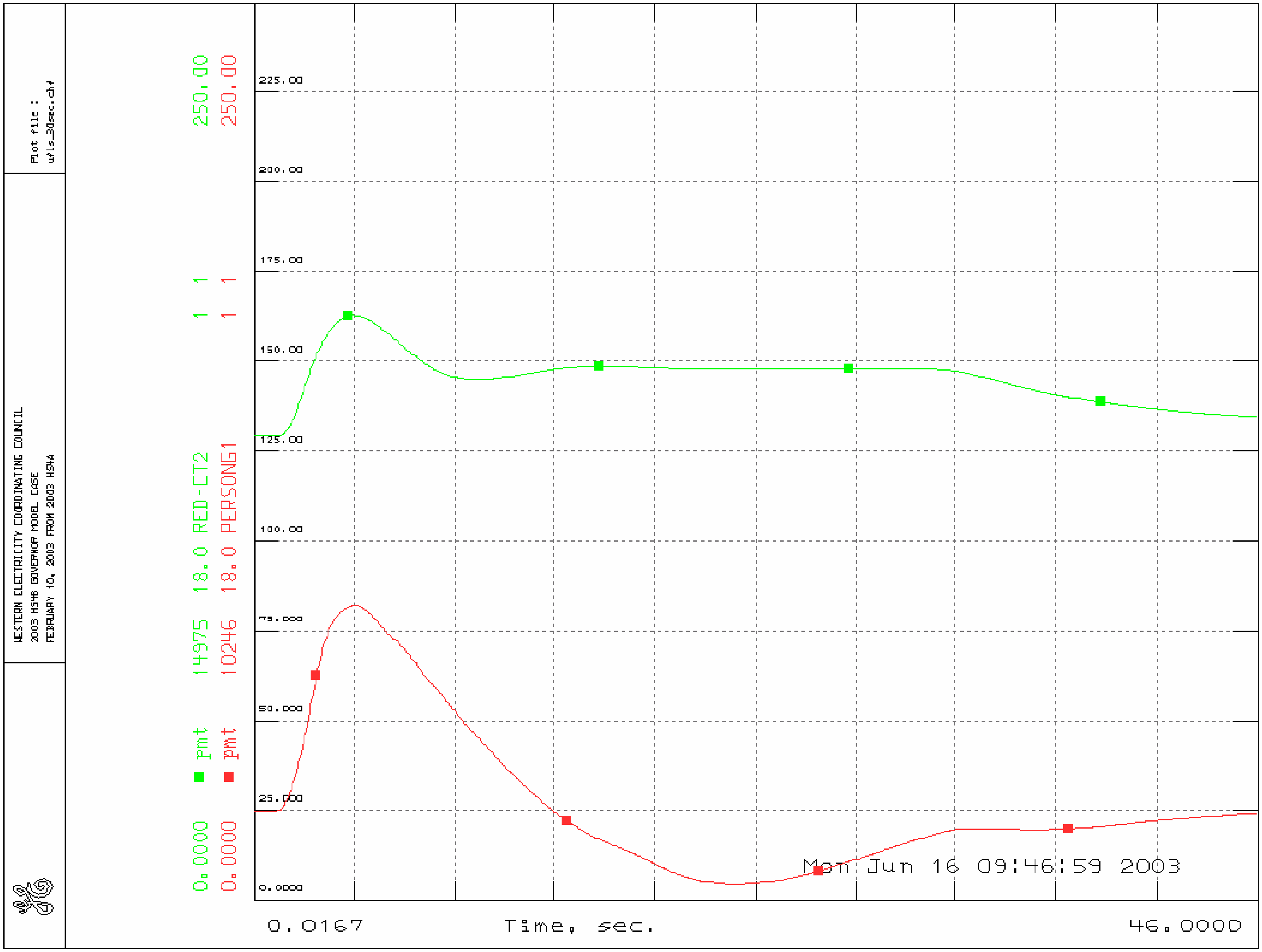


Figure 8
Response for Overfrequency
Base Load Flag =0   Load Controller Modeled

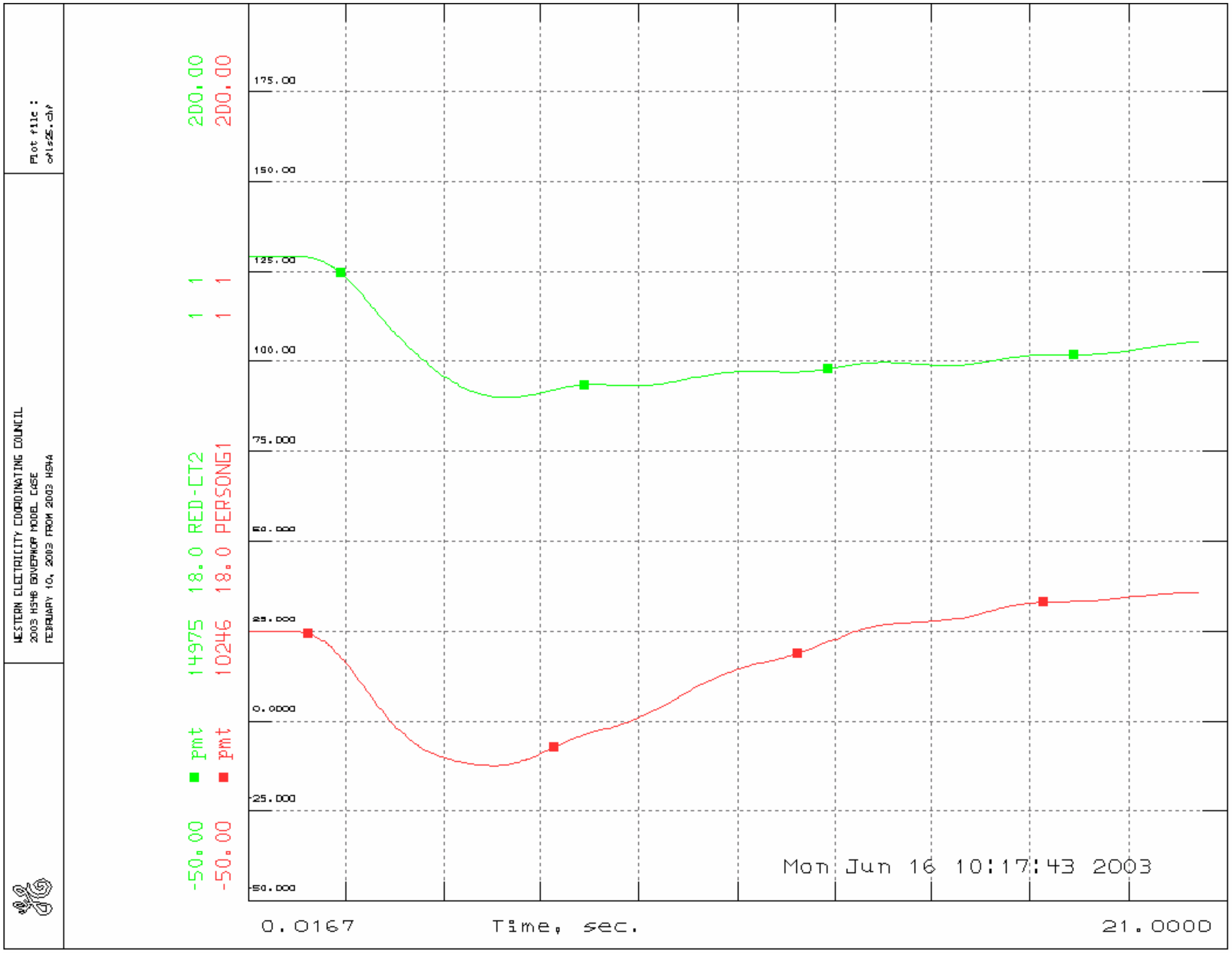


Figure 9
Response for Underfrequency
Base Load Flag =1   No Load Controller Modeled

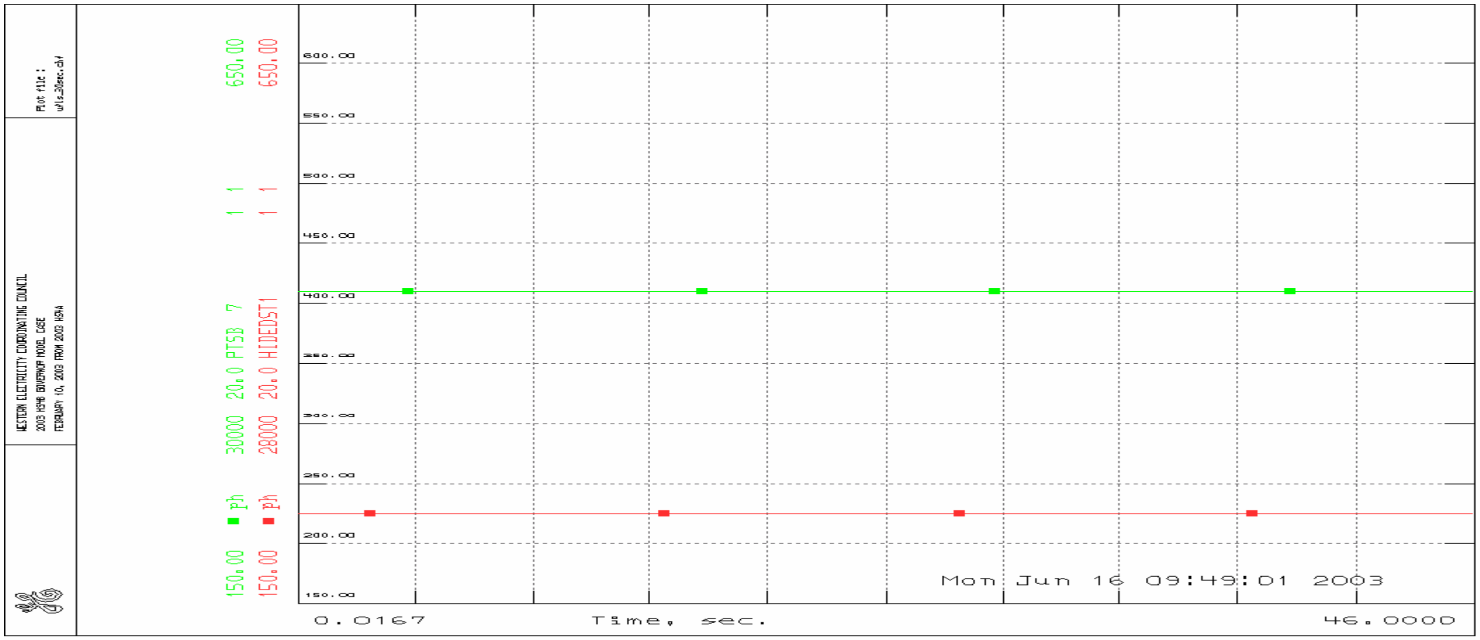


Figure 10
Response for Overfrequency
Base Load Flag =1   No Load Controller Modeled

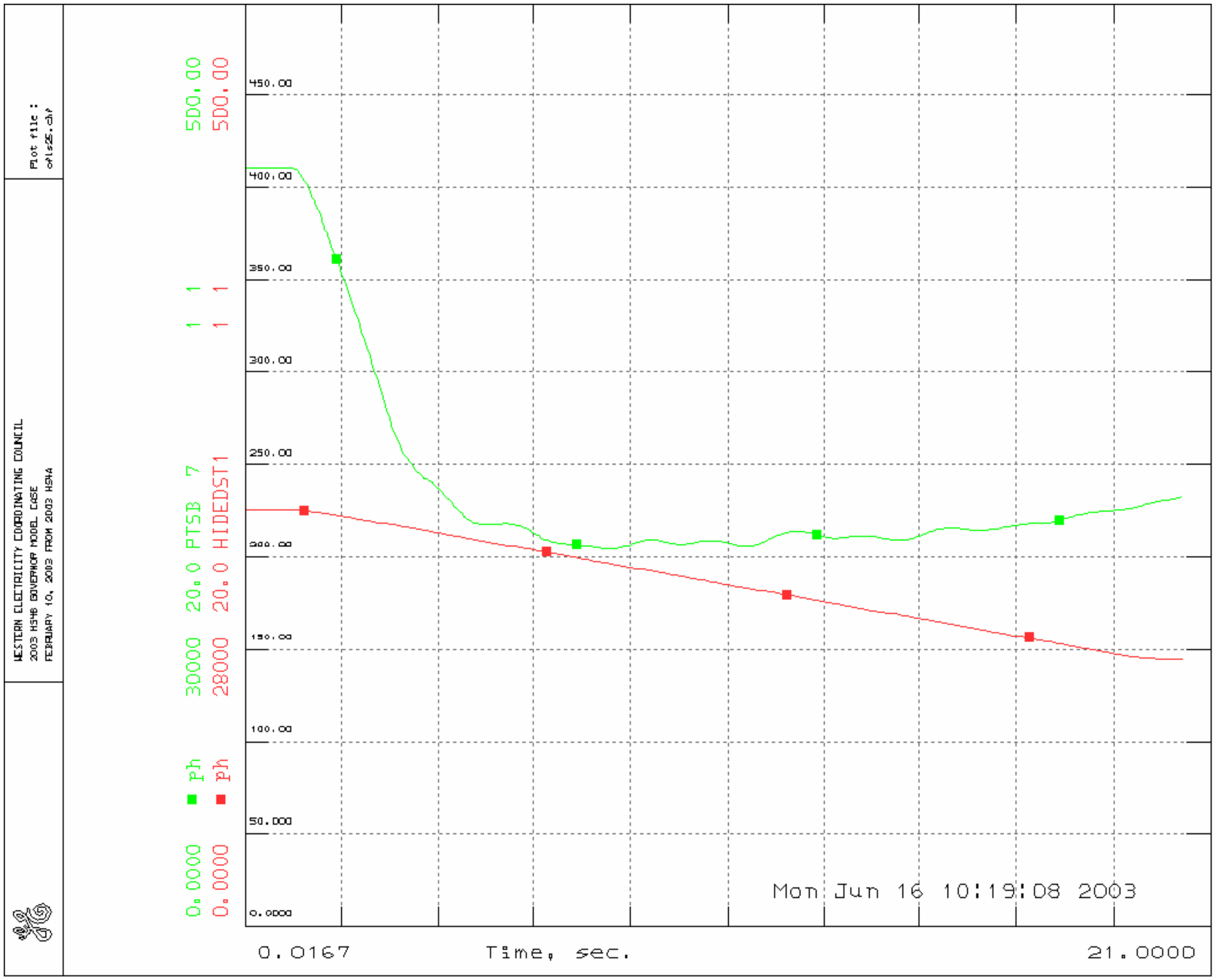


Figure 11
Response for Underfrequency
Base Load Flag =1   Load Controller Modeled

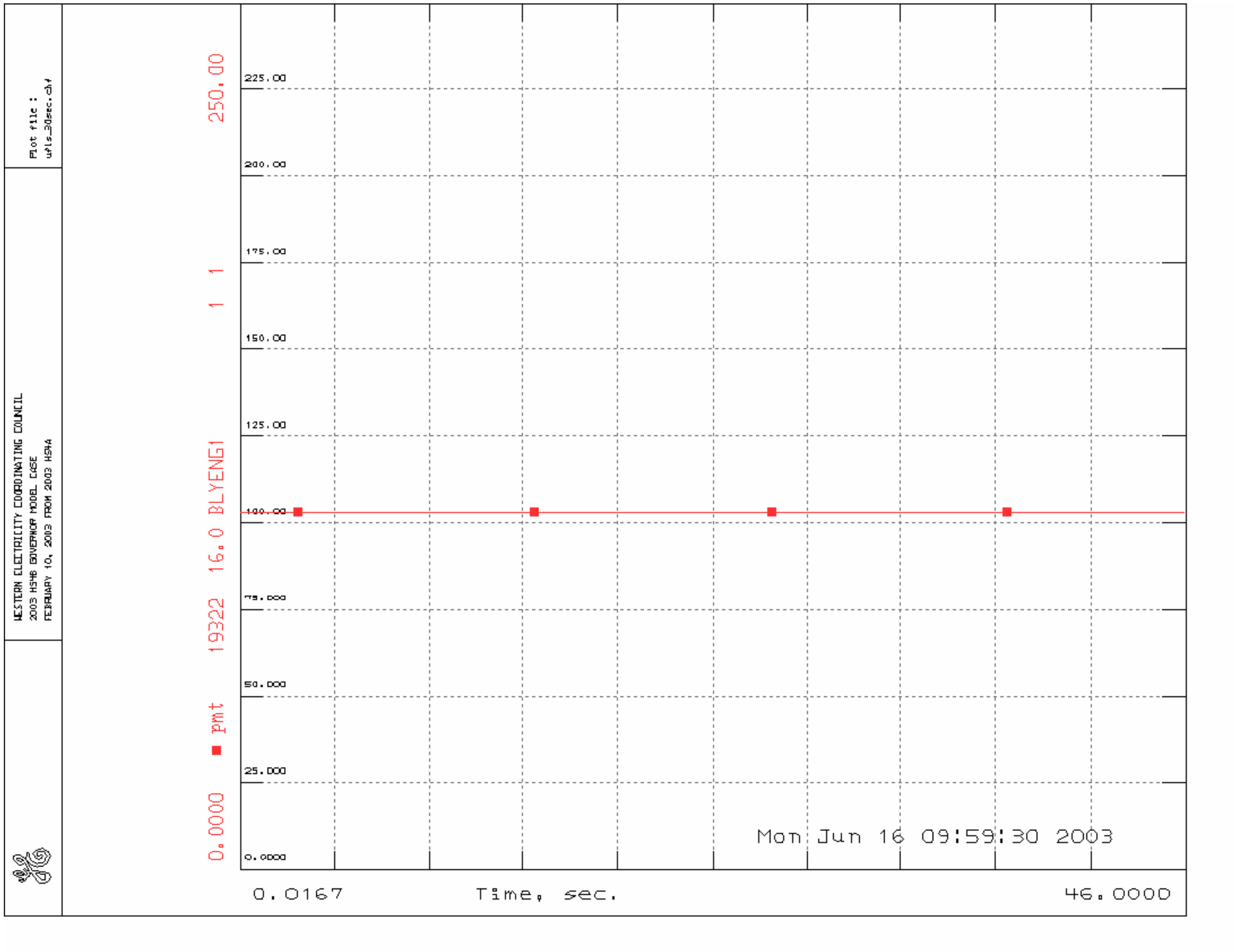
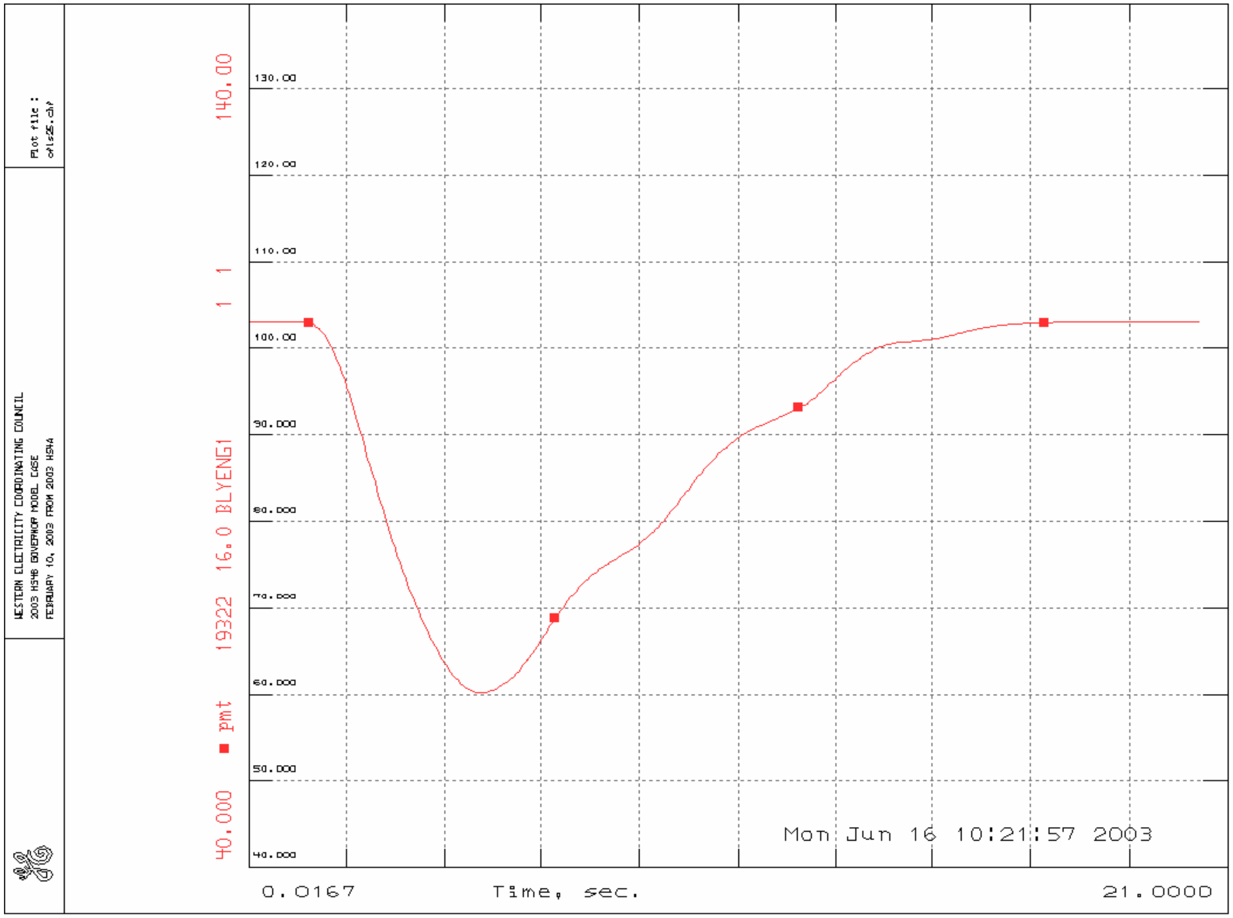


Figure 12
Response for Overfrequency
Base Load Flag =1   Load Controller Modeled



Reference D

Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Phase 3 Final Report

April 1, 2005

Prepared by:
Off-Nominal Frequency Work Group

Dana Cabbell (SCE, Chair)
Irina Green (CAISO)
Robert Jenkins (Mirant)
Anatoliy Meklin (PG&E)
John Phillips (Puget)
Alan Roth (Calpine)
Donald Davies (WECC)
John Simpson (Reliant)
Joe Tarantino (SPPC)

I. Introduction

NERC's Planning Standard III.D.S2.M4 states "Each Region shall periodically (at least every 5 years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of it Off-Nominal Frequency Plan." The WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan (WECC ONF Plan) was approved and recommended for implementation in 1997 in response to the July 2 & 3, 1996 and the August 10, 1996 system-wide disturbances occurring on the Western Electricity Coordinating Council (WECC) transmission system.

WECC initiated a review of the ONF Plan in September 2001, given that it had been five years since the implementation of WECC's ONF Plan. The Off-Nominal Frequency Work Group (ONFWG) was assigned to perform the technical analysis to determine if WECC's ONF Plan is still effective in arresting a system frequency decline due to a system-wide disturbance.

At the February 2003 PCC meeting, PCC accepted the Phase 1 Report, which determined that the 1997 WECC Coordinated Off-Nominal Frequency Plan meets the design specifications, though there may be opportunity for improvement. WECC Board approved the recommendations in the Phase 1.

PCC formed the Off-Nominal Frequency Advisory Task Force (ONFATF) to advise the TSS ONFWG on alternatives, risks, and policy issues related to the WECC ONF Plan. Upon completion of Phase 1, recommendations for further evaluation of the ONF Plan existed. The ONFATF developed six issues from these recommendations that required the ONFWG to continue its efforts into a Phase 2 of the evaluation of the WECC ONF Plan.

The recommendation from Phase 2 was to revise the instantaneous underfrequency generator trip setting in the WECC ONF Plan to 57 Hz from the present 56.4 Hz. The resulting generation requirement table is shown below:

Table 1: Generator Off-Nominal Frequency Performance Requirement

Under-frequency Limit	Over-frequency Limit	WECC Minimum Time
> 59.4 Hz	60 Hz to < 60.6 Hz	N/A (continuous operation)
≤ 59.4 Hz	≥60.6 Hz	3 minutes
≤ 58.4 Hz	≥61.6 Hz	30 seconds
≤ 57.8 Hz	-	7.5 seconds
≤ 57.3 Hz	-	45 cycles
≤ 57 Hz	>61.7 Hz	Instantaneous trip

The recommended revision was WECC Board approved in December 2003.

Upon completion of Phase 2, Phase 3 was initiated to address six action items that were either carried over from Phase 1&2 of the ONFWG's assignments, or were added upon completion of Phase 2. The six action items are summarized below:

- Action 1: Load Controller on Generators -- Evaluate the delay operation of the load controller during frequency excursions and identify what polices, modeling, EMS performance, and any other factors contributing to adverse system performance during the operation of the Off-Nominal Plan
- Action 2: Review and verify whether Figure 6 of the ANSI/IEEE C37.106-1987 reflects the worst case composite curve for generator operation during frequency excursions
- Action 3: Evaluate the impact of the non-compliant generator units on the WECC Off-Nominal Frequency Plan
- Action 4: Evaluate an over-frequency excursion to determine what if any changes to the generator over-frequency requirements should be recommended
- Action 5: Evaluate the automatic tie separation and load restoration requirements
- Action 6: Develop a single technical support document to provide the back-up documentation for the current WECC Off-Nominal Frequency Plan

The six action items were addressed in Phase 3 of the Evaluation of the WECC ONFWG Plan. This report summarizes the technical analysis used to develop the conclusions and recommendation associated with each of the six action items.

II. Conclusions

Action 1: Load Controller on Generators

- **Evaluate the delay operation of the load controller during frequency excursions**
- **Identify what polices, modeling, EMS performance, and any other factors contributing to adverse system performance during the operation of the Off-Nominal Plan**

Conclusion 1: The load controllers are returning the generators to their original set-point during an off-nominal frequency excursion.

Conclusion 2: Removal of the load controller model from the off-nominal frequency simulation resulted is a faster system recovery to normal frequency than when the load controller model was activated.

Conclusion 3: No need to activate the anti-stall load shedding blocks for the under-frequency excursion.

Conclusion 4: Further investigation required of the load controller model to verify that the response is correctly capturing actual system response characteristics.

Action 2: Review and verify whether Figure 6 of the ANSI/IEEE C37.106-1987 reflects the worst case composite curve for generator operation during frequency excursions

Conclusion 5: Comparison of the frequency versus time to trip curves revealed a discrepancy between WECC composite curve and the IEEE curves in ANSI/IEEE C37.106-1987.

Conclusion 6: Plotting on the comparison plot of the WECC composite curve and the IEEE curve the under-frequency load shedding blocks and the anti-stall load shedding blocks revealed a potential concern of lack of sufficient margin between the anti-stall load setting and the allowed tripping of generators.

Action 3: Evaluate the impact of the non-compliant generator units on the WECC Off-Nominal Frequency Plan

Conclusion 7: Due to non-compliant units, if initial loss of generation exceeds 26-27%, system frequency declines to the critical value of 58.1 Hz, where the further frequency decline can not be arrested due to 2 large blocks of non-compliant generators tripping at 58.1 Hz (2840 MW) and 58 Hz (2645 MW).

Conclusion 8: This scenario emphasizes the ONFWG Plan requirement that generator owners should obtain manufacturer permission to reset the instantaneous trip settings or automatically trip load to match the anticipated generation loss. Without these measures, the Plan provides the satisfactory system performance only for 26-27 % of instantaneous generation loss.

Action 4: Evaluate an over-frequency excursion to determine what if any changes to the generator over-frequency requirements should be recommended

Conclusion 9: Completion of Action 4 depends on the resolution of the blocked governor/load controller response issues discussion in Action 1.

Action 5: Evaluate the automatic tie separation and load restoration requirements

Conclusion 10: The automatic tie-line separation requirement is clearly stated on the ONF Plan to be tie-lines not to open until 57.9 Hz.

Conclusion 11: Some systems can not meet the automatic load restoration for certain levels of frequency over-shoot.

Conclusion 12: The ONF Plan language referring to automatic load restoration seems to be a guide, not a requirement.

Conclusion 13: For off-nominal frequency conditions, the ONF Plan prefers manual load restoration.

Conclusion 14: Relay Work Group concurs that the ONF Plan should be the enforcement document for both automatic load restoration and tie-line separation for off-nominal frequency excursions.

The ONF Plan is the Standard that should contain all system requirements related to off-nominal frequency system operation.

Action 6: Develop a single technical support document to provide the back-up documentation for the current WECC Coordinated Off-Nominal Frequency Plan

Conclusion 15: Need to maintain the historical perspective of the development of the WECC Coordinated ONFWG Plan.

III. Recommendations

Recommendation 1: Refer the load controller issue to the Model and Validation Work Group (M&VWG) and the Control Work Group (CWG) for further evaluation and investigation.

Upon resolution of the Load Controller issue, the gradual generation loss scenario as described in the Evaluation of the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, dated 1/21/03 should be evaluated.

Recommendation 2: Refer the need to update the generator composite curve to the CWG. The error in the composite curve used to define the generator off-nominal frequency performance requirements needs to be fixed. In addition, the generator composite curve should be updated to include the latest generator technology. The composite curve only includes unit-damage curve for steam units.

Recommendation 3: TSS should obtain all the generator off-nominal frequency settings as required in the WECC Coordinated ONF Plan. The data could be collected through the base case development of the dynamic file. A data submittal guide should be developed to obtain the requested data in a common format.

Recommendation 4: Maintain the generator off-nominal frequency performance requirement as stated in the ONF Plan. ONFWG obtained concurrence from Compliance Monitoring and Operating Practices Subcommittee (CMOPS), at which point, CMOPS will follow through on ensuring generators are in compliance with the requirements in the ONF Plan.

Recommendation 5: RWG and ONFWG concur that review the frequency value for tie-line separation through technical studies, along surveying members about their frequency setting to open tie-lines in an under-frequency condition. This work will need to wait for the load controller issues to be resolved.

Recommendation 6: Create a “Standard Document” listing the off-nominal frequency load shedding and restoration requirements with reference to the supporting reports and documents for each requirement.

IV. Discussion

Action 1: Load Controller on Generators -- Evaluate the delay operation of the load controller during frequency excursions and identify what polices, modeling, EMS performance, and any other factors contributing to adverse system performance during the operation of the Off-Nominal Plan

The re-evaluation of the ONF Plan to determine the impact due to the new load controller models repeated the over-frequency simulation performed for the 2005 Evaluation of the WECC Coordinated Off-Nominal Frequency Program – Phase 2 Report. The evaluation was to determine the governor response when the load controller model is not activated and to test if the initiation of the anti-stall load shedding blocks would still be required.

Using the new governor model (ggov1) with the turbine load control model (lcfb1) not activated, an instantaneous 20% loss of load throughout the WECC grid was simulated to drive the system into an over-frequency condition. Without the load controller models activated, the machine governors acted to restore system frequency. As discussed in the 2005 Evaluation of the WECC Coordinated Off-Nominal Frequency Program – Phase 2 Report, when the load controller models were activated, the governor was unable to reduce the generator output to restore system frequency.

For the under-frequency scenario, the investigation to support the 2005 Evaluation of the WECC Coordinated Off-Nominal Frequency Program – Phase 2 Report included a comparison of the with and without the load controller models for an under-frequency excursion. The under-frequency test was performed for the southern island scenario only. It was concluded the northern island scenario did not need to be simulated based on the results from the Phase 1 simulation of the southern and northern islands. The system response in both islands was similar during the simulated frequency excursion.

Removal of the load controller model from the under-frequency simulation resulted is a faster system recovery to normal frequency than when the load controller model was activated. In addition, the anti-stall load shedding blocks were not required to bring the system frequency back to normal as opposed to when the load controller model was activated.

Further investigation into the operation of the load controllers modeled is required. Refer the load controller issue to the Model and Validation Work Group (M&VWG) and the Control Work Group (CWG) for further evaluation and investigation.

Action 2: Review and verify whether Figure 6 of the ANSI/IEEE C37.106-1987 reflects the worst case composite curve for generator operation during frequency excursions

A concern was brought to the attention of the ONFWG and the ONFPTF regarding the generator requirement composite curve developed for the 1997 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan (ONF Plan). Recent generator designs have resulted in questioning the ONF Plan's off-nominal frequency requirements for generators.

To understand the concern, a composite of the five individual manufacturer graphs of steam turbine off-nominal frequency limitations from Figure 5 of the ANSI/IEEE C37.106-1987 document was plotted against the composite curve Figure 6 of the ANSI/IEEE C37.106-1987 document, and the WECC 5% loss of life composite curve. The result is shown in Figure 1.

Figure 1 reveals a discrepancy between WECC composite curve and the IEEE curves in ANSI/IEEE C37.106-1987. The discrepancy is in the time requirements between 58.5 Hz and 59.4 Hz. The source of this error could be the development of Figure 6 in the ANSI/IEEE C37.106-1987 document from Figure 5 in the same document. This inconsistency needs to be investigated further and fixed.

Figure 2 plots the anti-stall load shedding blocks onto Figure 1 and reveals a potential concern of lack of sufficient margin between the anti-stall load setting and the allowed tripping of generators.

The generator composite curve used in the ONF Plan needs to be updated. This work will be referred to the Control Work Group (CWG). The error in the composite curve used to define the generator off-nominal frequency performance requirements needs to be fixed. In addition, the generator composite curve should be updated to include the latest generator technology. The composite curve only includes unit-damage curve for steam units.

Action 3: Evaluate the impact of the non-compliant generator units on the WECC Off-Nominal Frequency Plan

A WECC Staff Report, dated April 28, 2003 summarized the response to the CMOPS Generator Off-Nominal Frequency Survey. Out of the 72 responses, WECC Staff received as of April 25, 2003, 49 respondents indicated ownership of generation. Of those, 22 responses that indicated all generators complied with the ONF Plan's generator requirements and 27 indicated that one or more generators do not meet all the provisions of the ONF Plan.

The MW amount of the non-compliant generators and their location was determined through the survey responses and are summarized in Table 2.

Table 2: Results of CMOPS' Generator Off-Nominal Frequency Survey

Region	MW	Over frequency Settings (Hz)	Under frequency Settings (Hz)
NWPP	5,100	60.6 to 61.2	56.9 to 59.4 33 units > 57 Hz 4,800 MW
RMPA	4,880	61.0 to 61.5	56.9 to 58.4 7 units > 57 Hz 3,900 MW
AZ/NM/SNV	7,630	N/A	57.0 to 58.5 15 units > 57 Hz 2,990 MW
CA/MX	1,760	60.5 to 61	57.0 to 59.1 12 units > 57 Hz 1,470 MW
Total	19,370		37 units > 57 Hz 13,160 MW

The Planning Coordination Committee's Steering Committee requested the ONFWG to evaluate the system reliability impact of the non-compliant generators.

The objective of the analysis was not to find an individual solution for each potential island but rather to illustrate the importance of the compliance with the WECC criteria. The following are the analysis' simplifications:

- non-compliant units are distributed uniformly through different WECC regions or potential islands, experiencing underfrequency;
- unit protection trips non-compliant generators 0.23 sec after approaching set frequency (same as the UFLS blocks)[1];
- initially lost units include only compliant units;

[1] Actual time delays can be longer for some units but not long enough to affect the conclusions. To affect the conclusions, the delays should be comparable with the delays of the anti-staling blocks (15, 30 and 60 seconds) and time of spinning reserve mobilization (1-3 min.).

- analysis was conducted using the simple single-machine dynamic model, validated in earlier studies (see report: Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, Appendix 5, UFLS Task Force, 2003).

Due to non-compliant units, if initial loss of generation exceeds 26-27%, system frequency declines to the critical value of 58.1 Hz, where the further frequency decline can not be arrested due to 2 large blocks of non-compliant generators tripping at 58.1 Hz (2840 MW) and 58 Hz (2645 MW). The complete analysis is located in Appendix 1 to this report.

Four possible options were developed to mitigate the potential system collapse due to the non-compliant generation:

- Option 1: Increase MW load to be shed in the load shedding blocks
- Option 2: Assume a lower initial loss of generation for the simulation
  - 26-27% vs. 30%
- Option 3: Trip equal amount of load when the generator trips or
- Option 4: Maintain the generator requirement as stated in the ONF Program Standard through Changing the trip settings on the generators

The following discusses the pro and cons for each option:

Option 1:

Increasing the amount of load shedding in each load-shedding block would mitigate the severe system collapse. However, why should the WECC systems increase its load shedding to cover for the noncompliant units?

Option 2:

Changing the study assumptions only masks the problem. This should not be done unless the new assumptions can be demonstrated to be realistic.

Option 3:

Not all generators have load to trip. These generators would have to contract with the host control area. But, the generator may not be delivering its power to the host control area. This scenario emphasizes the ONFWG Plan requirement that generator owners should obtain manufacturer permission to reset the instantaneous trip settings or automatically trip load to match the anticipated generation loss. Without these measures, the Plan provides the satisfactory system performance only for 26-27 % of instantaneous generation loss.

Option 4:

As with all Reliability Standards, a set of requirements are established for all members' compliance.

ONFWG recommends the generator off-nominal frequency performance requirement be retained as stated in the ONF Plan. ONFWG obtain concurrence from Compliance

Monitoring and Operating Practices Subcommittee (CMOPS). CMOPS will follow through on ensuring generators are in compliant with the requirements in the ONF Plan.

Action 4: Evaluate an over-frequency excursion to determine what if any changes to the generator over-frequency requirements should be recommended

A system test of an over-frequency excursion was performed in support of the 2005 Evaluation of the WECC Coordinated Off-Nominal Frequency Program – Phase 2 . However, completion of the analysis to determine if changes are required for the over-frequency generator requirement depends on resolution of the blocked governors/load controllers response issues for the new governor models as outlined in Action Item 1.

Action 5: Evaluate the automatic tie separation and load restoration requirements

Automatic Tie Separation

The following is the question posed to the ONFWG: Should the language describing the Automatic Tie-line separation requirement in the ONF Plan be strengthen? The conclusion the ONFWG came to was the requirement in the ONF Program is clear: tie-lines not to open until 57.9 Hz. Below is the tie-line requirement from the ONF Plan:

> Recommendation 4: Intentional tripping of tie lines due to underfrequency is permitted at the discretion of the individual system, providing that the separation frequency is no higher than 57.9 Hz with a one-second-time delay. While acknowledging the right to trip tie lines at 57.9 Hz, the preference is that intentional tripping not be implemented.

The question the ONFWG asked is: Should the ONF Plan be the enforcement document or is this requirement already part of the MORC or WECC Operating Policies?

Automatic Load Restoration

Some systems can not meet the automatic load restoration for certain levels of frequency over-shoot. The ONFWG reviewed the requirement in the 1997 ONF Plan and its supporting discussion. Below are the two automatic load restoration recommendations from the 1997 ONF Plan:

> Recommendation 3A: All systems that intend to automatically restore load following a load-shedding event shall demonstrate their compliance with MORC. In any event, automatic restoration shall begin no sooner than thirty

> minutes after the frequency has been restored to levels above 59.95 Hz and no faster than 2% of the system load every five minutes. If the control area cannot meet the WECC ACE requirements when automatic or manual restoration begins, the dispatcher must manually trip corresponding load to balance available generation and load. Manually controlled load restoration, if available and practical, is preferred over automatic restoration.
>
> Recommendation 3B: To the extent that restoring load depends on the availability of transmission facilities, attempts to restore load shall not be done until those transmission facilities are operational. (Reference A)

The automatic load restoration language seems to be a guide, not a requirement, since it caveats the requirement as for "all systems that intend to automatically restore load…" In addition, the ONF Plan states a preference for manual load restoration

Based on the impression that the ONF Plan language seems to be a guide, the ONFWG asked the following three questions: 1) Do other Operating Polices/Documents have stronger language regarding automatic load restoration?; 2) What is the best WECC Document to include the automatic load restoration requirements for an off-nominal frequency event?; and 3) For overshoot situations, can the system rely on governor action?

The ONFWG sought the Relay Work Groups advice if the ONF Plan should be the enforcement document for both tie-line separation and automatic load restoration for off-nominal frequency excursions. Relay Work Group agrees that the ONF Plan should be the enforcement document for both automatic load restoration and tie-line separation for off-nominal frequency excursions. The ONF Plan is the Standard that should contain all system requirements related to off-nominal frequency system operation.

RWG and ONFWG concur that review the frequency value for tie-line separation through technical studies, along surveying members about their frequency setting to open tie-lines in an under-frequency condition. This work will need to wait for the load controller issues to be resolved.

Action 6: Develop a single technical support document to provide the back-up documentation for the current WECC Coordinated Off-Nominal Frequency Plan

The re-evaluation of the 1997 WECC Coordinated Off-Nominal Load Shedding and Restoration Plan was started in 2001 and has gone through three separate phases. The three phases have included evaluation of the ONFWG Plan and re-evaluation of the Plan as questions arose and system modeling changes occurred. It is evident that there is a strong need to encapsulate the reports from the three phases, along with the original 1997 ONF Plan. To maintain the historical perspective of the development of the WECC Coordinated ONFWG Plan, the ONFWG recommends creating a "Standard

Document" listing the off-nominal frequency load shedding and restoration requirements with reference to the supporting reports and documents for each requirement.

Figure 1: 5% Loss of Life - Comparison With WECC Standard

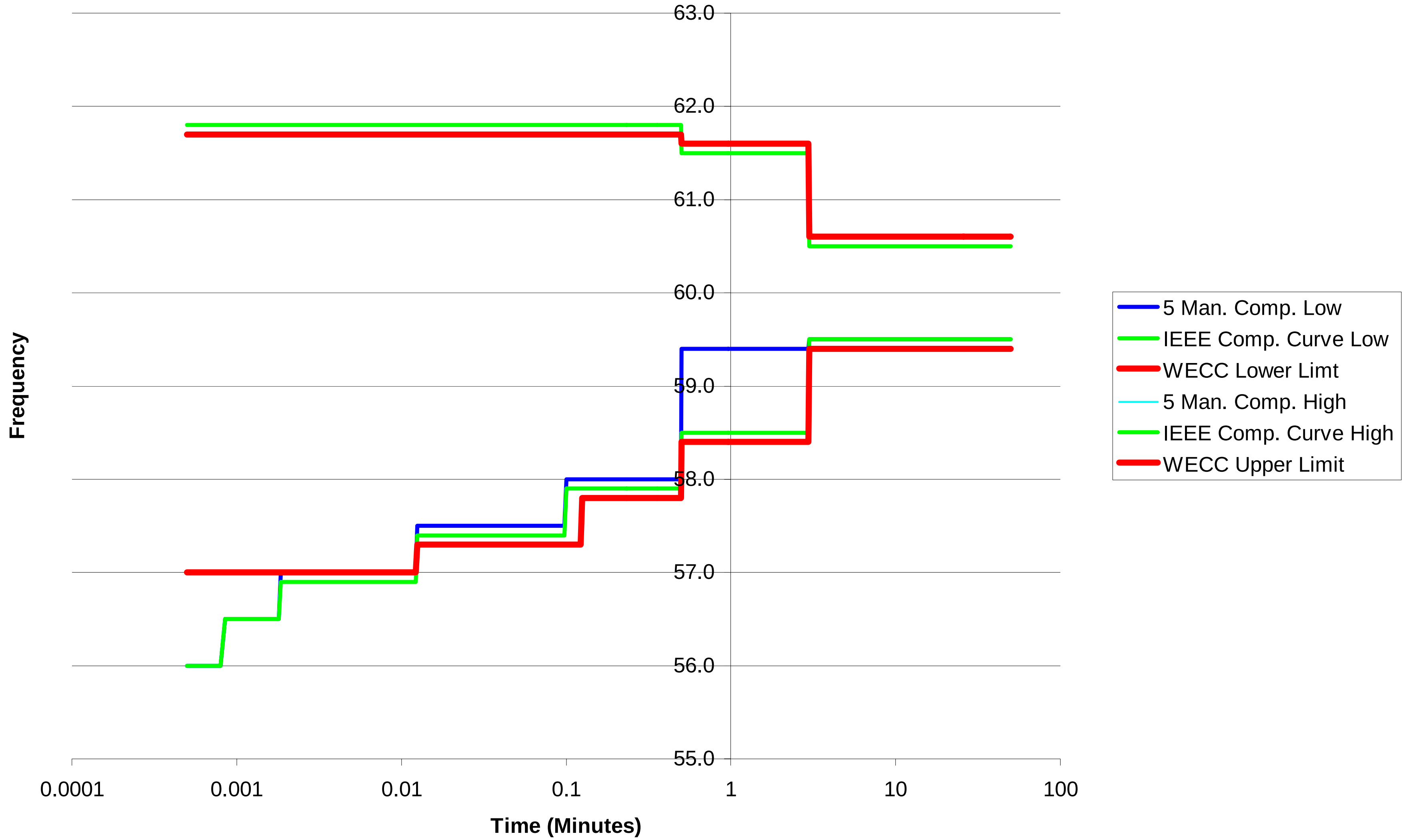
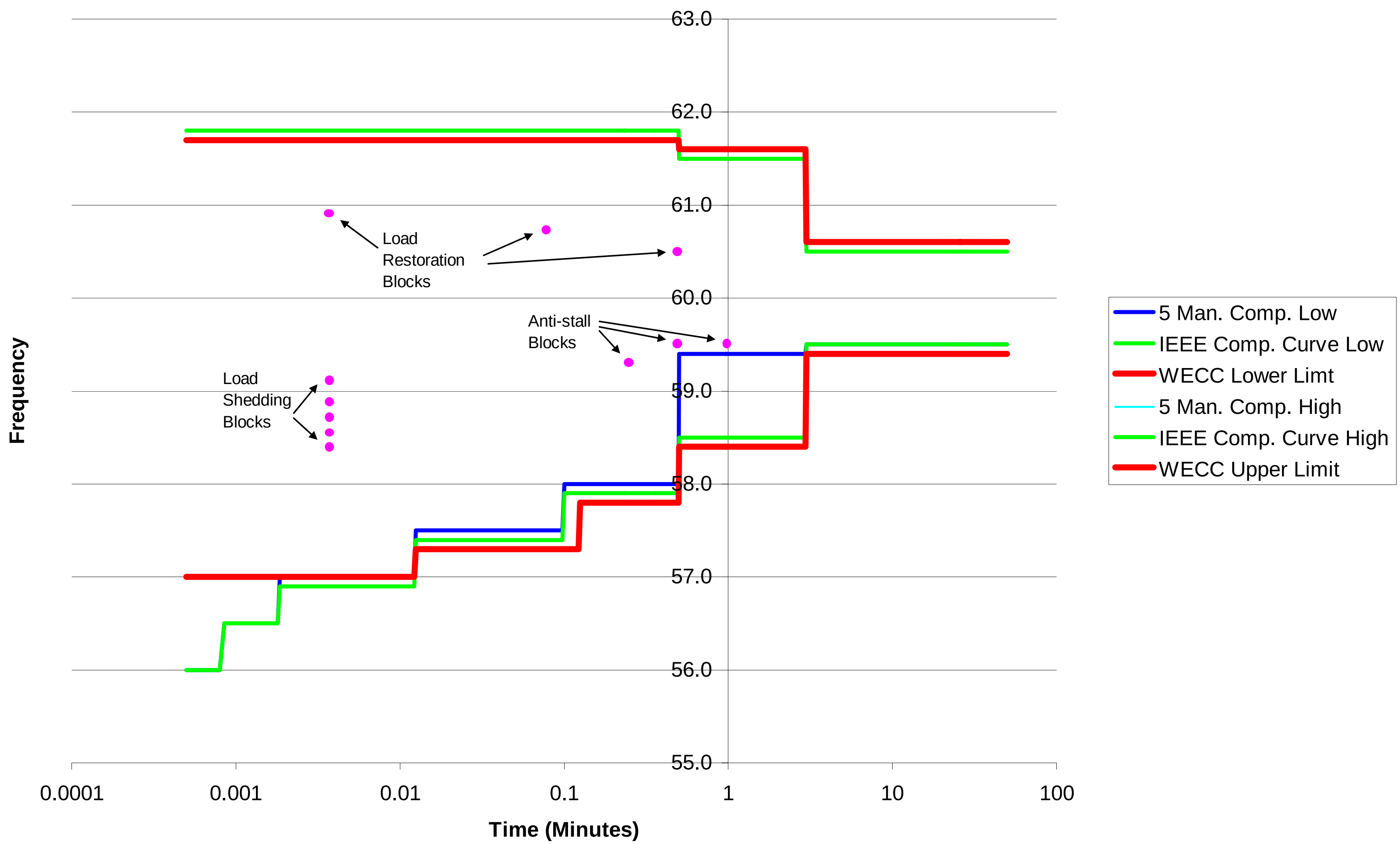


Figure 2: 5% Loss of Life - Comparison With WECC Load Shedding Points



Appendix A

Impact of the Non-Compliant Underfrequency Trip Settings

General

The recent Generator Frequency Settings Survey, conducted by CMOPS revealed significant number of units with underfrequency trip settings, which are greater than 57 Hz allowed by the recently revised WECC requirement[2]. The total capacity of non-compliant units is about 12,000 MW or 8.5% of WECC peak load. The aggregated results of the survey are presented in Table 1. The numbers in the Table 1 determine MW or percentage of WECC generation to be lost with each increment of frequency decline. The percentages are calculated using the MW results from the survey related to the 140,000 MW of WECC load.

Table 1

f (Hz)	non-compl MW	non-compl %	UFLS (%)	Σ %
59.4	-50	-0.037		-0.037
59.1			4.75	4.75
58.0			5.25	5.25
58.7			5.75	5.75
58.5	-610	-0.436	6	5.564
58.4	-665	-0.474		-0.474
58.3			6	6.00
58.2	-670	-0.479		-0.479
58.1	-2840	-2.028		-2.028
58.0	-2645	-1.890		-1.890
57.9	-955	-0.682		-0.682
57.8	-1480	-1.057		-1.057
57.7	-125	-0.090		-0.090
57.6	-970	-0.693		-0.693
57.5	-605	-0.434		-0.434
57.4	-245	-0.175		-0.175
56.9	-75	-0.053		-0.053
Total %	-11935	-8.528	27.75	19.22

The following analysis has been initiated due to the significant difficulties in implementation of Recommendation 5B of the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, developed in 1997. The recommendation says: “Systems that have generators that do not meet the requirements … must automatically trip additional load to match the anticipated generation loss…” This happened to be not practical because generation owners mainly do not have control over load to shed in the surrounding or remote control areas. This is particularly not practical because a unit trip affects not only real power but also reactive support in the surrounding area. The choice of load to shed becomes additionally limited because the

[2] The old requirement allowed 56.4 Hz.

recommended action should be allocated in this area to match the loss of reactive support[3]. It should be admitted that Recommendation 5B contradicts in certain extent the WECC policy focused on prevention of additional unit trips during disturbances (such as activated by Over Excitation Limiters).

The following presents consequences of the non-compliant unit trips not accompanied by the Recommendation 5 actions. This is based on the above-mentioned difficulties to implement Recommendation 5 and on the absence of any impact, if the matching loadshed accurately compensates losses of real power and reactive support.

The objective of the following analysis is not in finding an individual solution for each potential island but rather in illustrating the importance of the compliance with the WECC criteria. This objective justifies the following analysis simplifications:

- non-compliant units are distributed uniformly through different WECC regions or potential islands, experiencing underfrequency;
- unit protection trips non-compliant generators 0.23 sec after approaching set frequency (same as the UFLS blocks)[4];
- initially lost units include only compliant units;
- analysis was conducted using the simple single-machine dynamic model, validated in earlier studies (see report: Evaluation of WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan, Appendix 5, UFLS Task Force, 2003).

System performance with 30% initial loss of generation and non-compliant underfrequency trips

The existing UFLS system has been designed to prevent frequency dips (in simulations) lower than to 57.9 Hz. This frequency was determined in consideration that frequency can actually deviate to 56.4 Hz because of the simulation model inaccuracies, related mainly to UFLS block sizes. The recent change of the WECC limit from 56.4 Hs to 57 Hz does not change the design frequency 57.9 Hz but rather reduces the margin from 1.5 Hz to 0.9 Hz. To obtain maximum frequency dips from simulations, this new margin should be interpreted in terms of UFLS block inaccuracies.

Figure 1 shows that the maximum credible generation loss of 30% causes frequency decline close to the design frequency 57.9 Hz. This result is obtained in assumption of the instantaneous 30% loss of generation and accurate execution of the existing UFLS blocks as shown in Table 2.

---

[3] Immediate non-compliant unit transfer to synchronous condenser mode for 2-3 min would not affect reactive support. The possibility of such transfer and how this can be helpful for turbine blades should be discussed with the experts.

[4] Actual time delays can be longer for some units but not long enough to affect the conclusions. To affect the conclusions, the delays should be comparable with the delays of the anti-staling blocks (15, 30 and 60 seconds) and time of spinning reserve mobilization (1-3 min.).

Figure 1

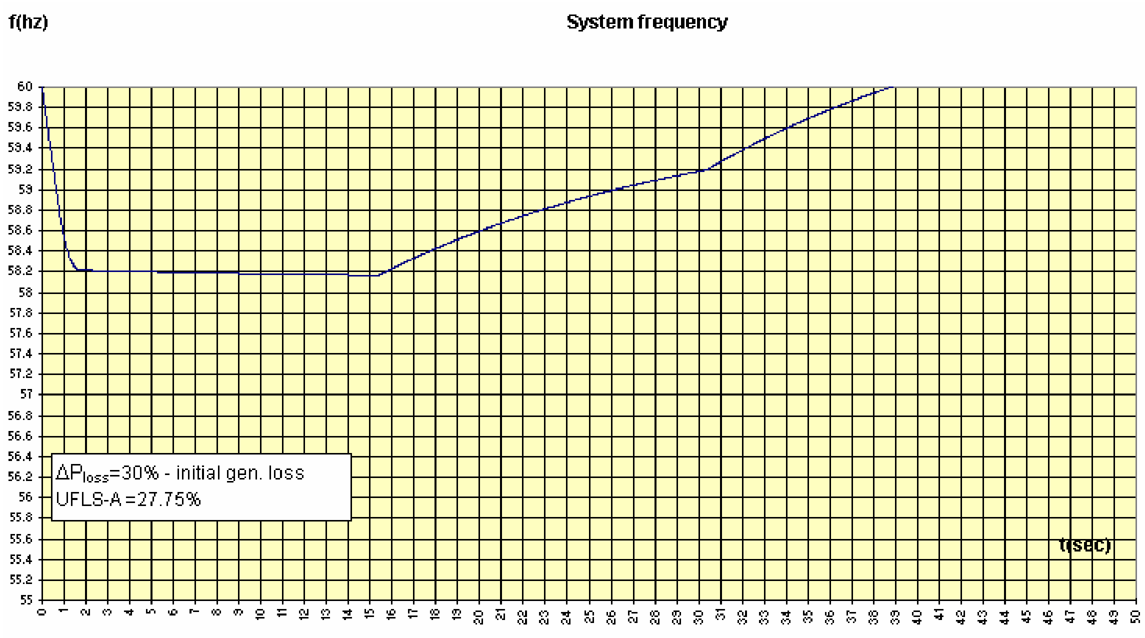


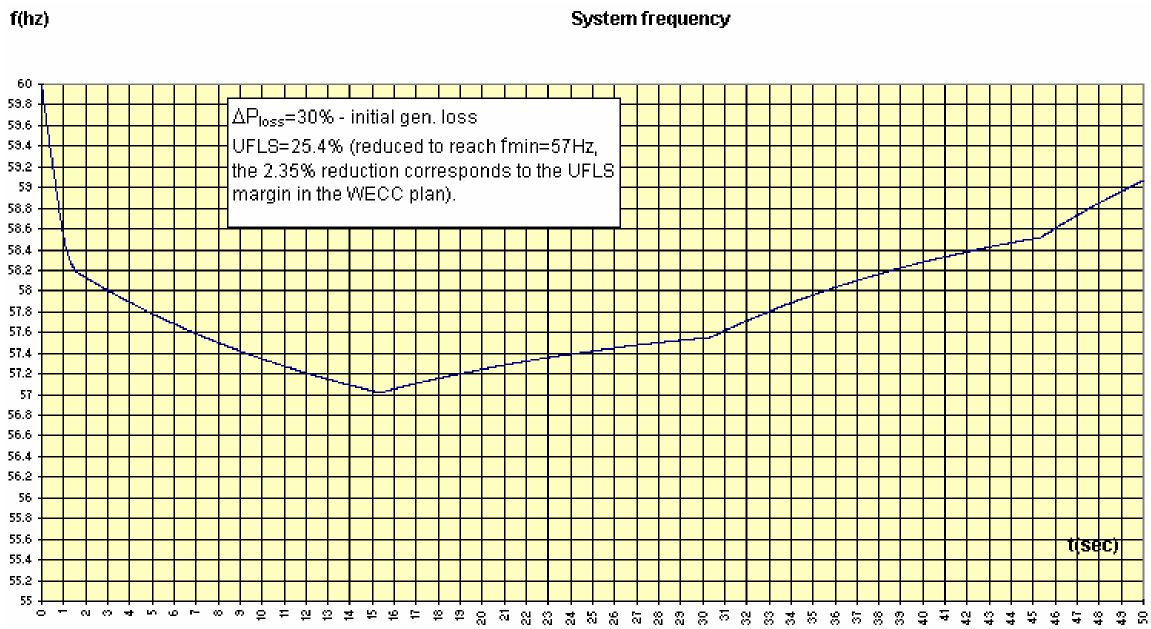
Table 2

UFLS-A - instantaneous *UFLS* (14 cycles)	*UFLS-B* - anti-stalling *UFLS*
Block 1 - 59.1 Hz, 4.75%,	Block 1 – 59.3 Hz, 2%, 15 sec.
Block 2 - 58.9 Hz – 5.25%,	Block 2 – 59.5 Hz, 1.5%, 30 sec.
Block 3 - 58.7 Hz – 5.75%,	Block 3 – 59.5 Hz, 1.78%, 60 sec.
Block 4 - 58.5 Hz – 6.0%,	
Block 5 - 58.3 Hz – 6.0 %	

.

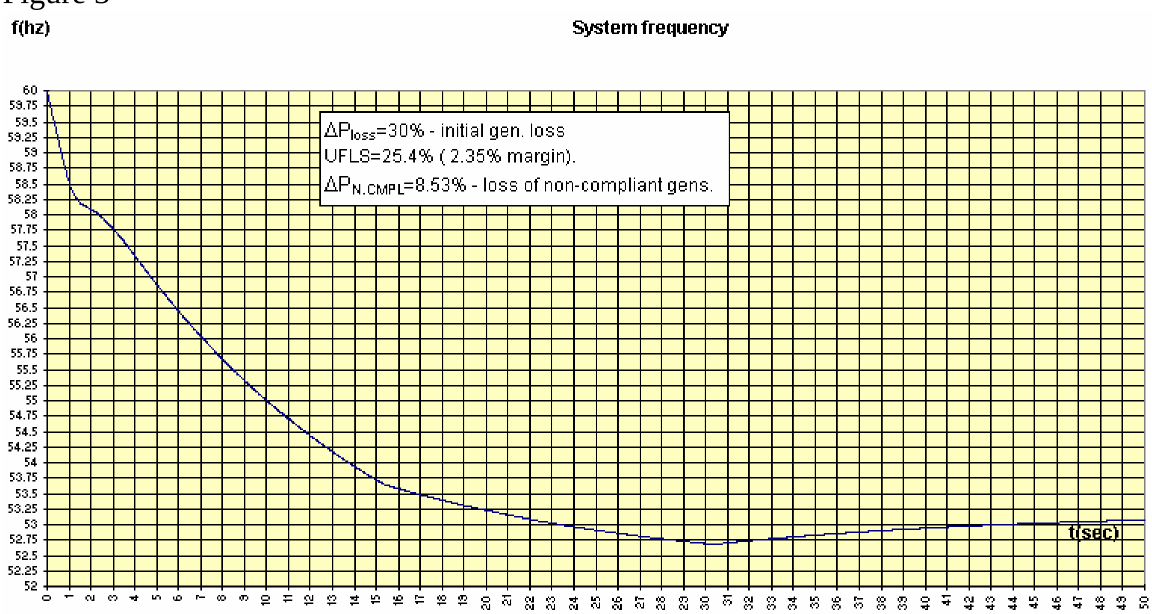
Figure 2 shows that frequency approaches 57 Hz if total MWs of five UFLS-A blocks are reduced from 27.75% to 25.4% or 0.47% per block.

Figure 2



Therefore, the maximum possible frequency dips could be obtained from simulations with total MWs of UFLS-A reduced to 25.4%. This UFLS-A reduction may produce frequency deviations lower than to 57.9 Hz and cause trips of the non-compliant units with underfrequency trip settings between 57.9 and 57 Hz. Figure 3 shows that system frequency may decline to 52.7 Hz if the matching load shed does not accompany the loss of 8.3% of non-compliant units. This result corresponds to the maximum inaccuracy of UFLS-A, resulting in execution of 25.4% of load shed instead of 27.75%.

Figure 3

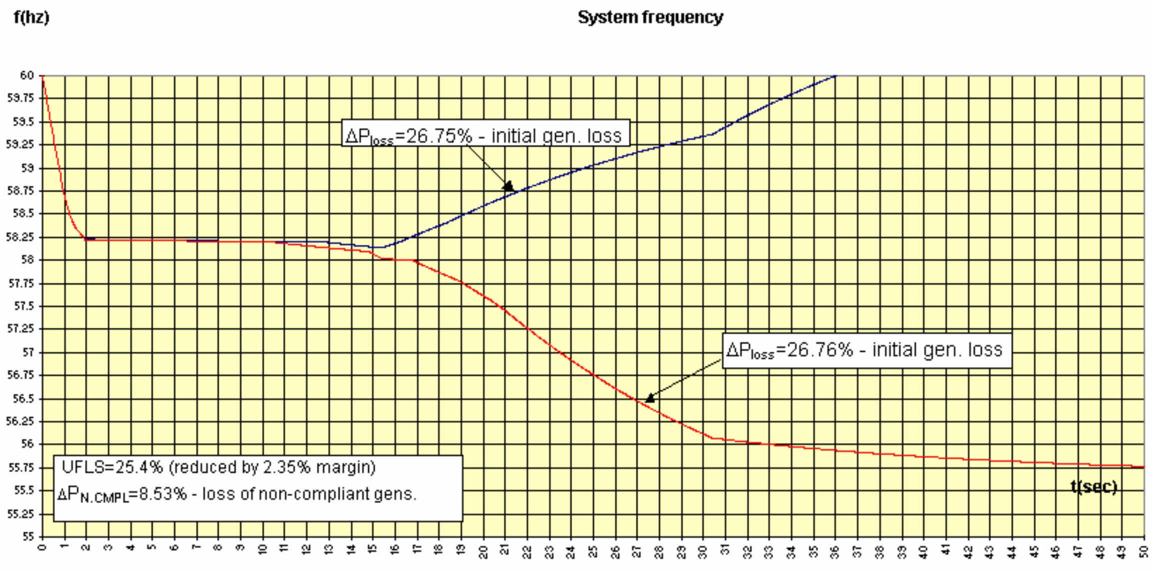


Reduction of UFLS capability due to non-compliant trips

Existing UFLS prevents frequency decline to 57 Hz, if initial loss of generation ΔP_{loss} does not exceed 26.75%. This value of ΔP_{loss} counts inaccuracy of UFLS-A, reducing its total value to 24.5%.

Reduction of ΔP_{loss} is 30 – 26.75 = 3.25%, what is much less than 8.53% of total non-compliant unit generation. This is because UFLS action on reduced ΔP_{loss} is sufficient to cease frequency above 58.1 Hz and to prevent tripping of non-compliant units with lower trip settings. The 0.01% increase of ΔP_{loss} brings frequency to 58.1 Hz and causes significant (2.03% in Table 1) additional trip of non-compliant generators. This reduces frequency lower than 58 Hz with the 1.9% generation trip and leads finally to the trip of all non-compliant units. Figure 4 shows frequency plots for ΔP_{loss}=26.75% and ΔP_{loss}=26.76%.

Figure 4



Measures to prevent violations of the 57 Hz WECC requirement on 30 % loss of generation

The existing UFLS with its settings and volumes provides a good compromise between maximum frequency deviations and possibilities of unnecessary load shedding or over shedding. Increase of the UFLS blocks to cover non-compliant units is very undesirable because this would increase over shedding and supposed to be very laborious and expensive to implement. However, some simulations were conducted to determine the UFLS-A volume, preventing violations of 57 Hz criteria for $\Delta P_{loss} = 30\%$.

Figure 5

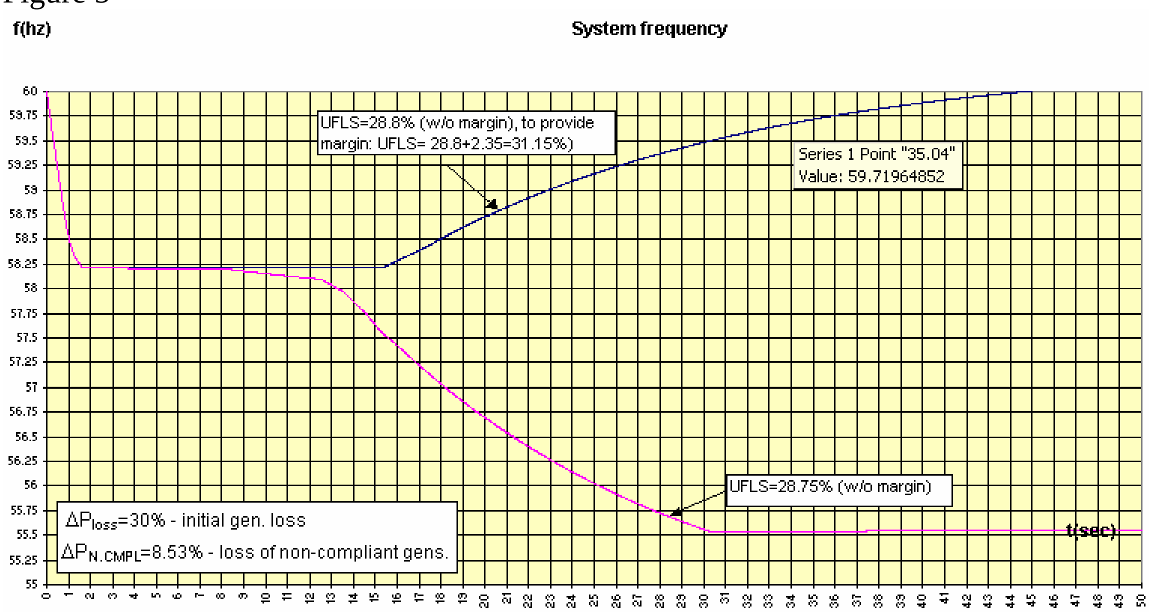


Figure 5 shows that violations of the criteria can be prevented with the UFLS-A increase from 27.75% to 31.15% with equal increase of all five blocks. The actual UFLS-A volume in the simulation was 28.8% and the additional 2.35 % cover the inaccuracy margin. Similarly to the Figure 4 simulation, this UFLS action excludes trips of non-compliant units with underfriquency protection settings 58.1 Hz and lower. The 0.05% decrease of UFLS-A leads to the trip of all non-compliant units and significant frequency decline.

The more desirable solution is in bringing unit protection in compliance with the 57 Hz criteria. Many owners/manufacturers may reevaluate a risk of lower settings based on very low probability of severe under frequency events. The most urgent task would be readjustment of small number of units with settings 58.2 Hz and greater, carrying 1.43% of system generation. This measure makes underfrequency simulation for ΔP_{loss} = 30% and UFLS-A=27.75% identical to Figure 1. However, this does not provide any inaccuracy margin.

Conclusions

1. WECC Off-Nominal Frequency Load Shedding Plan recommends to trip additional load to match the loss of generators with non-compliant under frequency trip settings. The recommendation is difficult to implement because a) generation owners do not have control over load to shed; b) the automatic load trip should be precisely allocated to match the loss of real power and reactive support.

2. System frequency may decline to 52.7 Hz on 30% loss of generation if the matching load shed does not accompany the following loss of 8.3% of non-compliant units. This result corresponds to the maximum inaccuracy of the existing UFLS-A, resulting in execution of 25.4% of loadshed instead of 27.75%.

3. Existing UFLS prevents frequency decline to 57 Hz, if initial loss of generation does not exceed 26.75%.

4. Violations of the 57 Hz criteria can be prevented with the UFLS-A increase from 27.75% to 31.15%. However, this solution would increase over shedding and supposed to be very laborious and expensive to implement.

5. The more desirable solution is in bringing unit protection in compliance with the 57 Hz criteria. Readjustment of small number of units with settings 58.2 Hz and greater to 58 Hz and lower would exclude violations of this criteria in the case of 30% loss of generation with precise execution of the existing UFLS. The farther readjustment would guarantee that those units do not trip because of the UFLS inaccuracies.

I. INTRODUCTION

The Relay Work Group's investigation into the coordination of the Western Systems Coordinating Council (WSCC) load shedding program has revealed that a variety of interpretations of system decaying frequency dynamics and underfrequency relay characteristics exists among member systems. This has resulted in inequitable shedding of loads during underfrequency excursions in some WSCC areas. At the request of the WSCC Technical Operations Subcommittee, the Relay Work Group has developed this guide to assist member systems in designing better underfrequency load shedding programs.

The objective of any underfrequency load shedding program must be to arrest the frequency decay following a deficit in generation. Ideally, within a group of interconnected systems, load shedding should be designed so that each member system shares equitably in the load shedding process. This ideal is not completely attainable because of differing system frequency decay dynamics. The problem is further complicated by the use of relays with different time-frequency characteristics. A knowledge of these dynamics and of the varying characteristics of the relays that are available for load shedding will allow operating and relay engineers to optimize the load shedding programs within their interconnected system areas.

II. OBJECTIVES

The objectives of this guide are:

1. Explain the dynamics of declining frequency on a generation deficient system.
2. Outline the static, dynamic, and environmental characteristics of presently available types of underfrequency relays.
3. Recommend relay types and methods of application.

III. CONCLUSIONS

Coordinated planning, design and implementation of underfrequency load shedding programs will minimize the effects of a serious loss of generation on a power system and will facilitate system restoration.

Within the WSCC interconnection, the following considerations should be kept in mind while developing such a program:

1. Frequency excursions below 59.5 Hz will probably not occur except after a WSCC breakup, so coordination of underfrequency programs between systems may be confined to post-disturbance islands.
2. Cooperative planning of the load shedding and restoration programs of all individual systems within a probable islanded area is vital to the success of such programs and contributes to equitable treatment of the customers of each system.
3. Minor frequency differences that may exist across an island during an underfrequency excursion can cause inequitable load shedding even with a well designed load shedding program.
4. Care must be exercised to assure coordination of load shedding with underfrequency dropping of generators.

Frequency decay rates following the loss of generation may be calculated for any given island and coordinated load shedding schemes may be designed that will arrest frequency decay. Methods for accomplishing this are described in this guide.

Load shedding speed and accuracy requirements will determine the type of relays to be used. Digital relays will give the most accurate and consistent performance and will be the least difficult to apply successfully.

Because of the accuracy sensitivity of electromechanical relays to voltage, temperature, and frequency decline rate these relays must be applied with discretion. The use of digital and electromechanical relays in the same load shedding program is impracticable.

Security and dependability factors will determine the design of load shedding relay schemes. These factors will depend on the size and configuration of the utility or island and the size and type of load to be shed by each load shedding relay scheme.

IV. RECOMMENDATIONS

Each WSCC member system should actively participate in an underfrequency load shedding program. The step-by-step method recommended for each member system is as follows:

1. Determine in which post WSCC breakup island your system is most likely to be included.
2. Meet with representatives of the systems in that island.
3. Determine the maximum generation deficiency that is likely to occur in your island.
4. From this generation deficiency and the island's inertia, determine the maximum rate of frequency decline that may occur. This should be done for both peak load and minimum load to determine the most severe condition.
5. Establish the island's minimum permissible frequency. The existence of thermal generation and its low frequency limitations are the prime determinant for this factor.

RECOMMENDATIONS (Continued)

6. Design an underfrequency load shedding program that will arrest the island's frequency decline before the minimum permissible frequency is reached. The following decisions will be the product of this design:

   a. The number of load blocks to be shed as the frequency declines.

   b. The size of the blocks of load that are to be shed.

   c. The settings of the relays that are to initiate the shedding of each block of load.

   d. The type of relays that may or must be used.

7. Verify the compatability of the underfrequency load shedding program with any underfrequency generator dropping programs that may exist within the island.

8. Assure that load restoration programs within the island are compatible.

9. Agree to cooperate in the island load shedding program by implementing the decisions of Step 6 within your system.

10. Periodically review and update load shedding programs to consider:

    a. Changes in the characteristics of system load and generation.

    b. Changes in post WSCC breakup islanding patterns.

V. GENERAL PRINCIPLES

A. Variation of Frequencies Within an Interconnected Area

The classical methods for determining the rate of frequency decline for a given group of interconnected systems describe a smooth exponential drop in frequency with time. Actual system performance will generally follow the calculated rate of decline but will oscillate above and below the exponential curve. At a given instant, various points of the interconnected area will have different frequencies.

These actual system performance characteristics are illustrated by Figure 1, a record of frequencies at San Francisco on the Pacific Gas and Electric Company (PG and E) system and at Vincent Substation on the Southern California Edison Company (SCE) system for a historical WSCC breakup of August 4, 1972. Note that at 0.5 second, the frequency difference between these two locations exceeded 0.2 Hz.

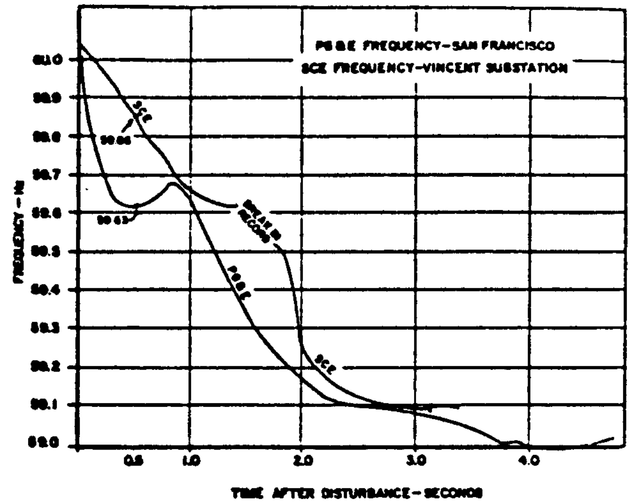


Fig. 1 Recorded frequencies at two separated points on an islanded California-Arizona-interconnection that occurred at 1757 hrs. August 4, 1972 when the AC Pacific Intertie was separated at Malin and Arizona and Utah were separated by the rate-of-change-of-power relay on the Four Corners-Eldorado Line.

A 1974 Heavy Summer (1974 HS) stability study which includes load shedding in a digital simulation illustrates the difference in frequency that occurs even when the initial disturbance is relatively small (Figure 2).

In this case, the southwest systems were separated by opening the dc intertie and the two 500 kV ac intertie lines in northern California, causing a 9.69 percent overload on the remaining southwest generation. Note that the freqquency difference at centrally located load buses in widely separated locations, such as Tesla and Mesa, (Fig. 2e) is relatively small, but at those buses that are close to generating stations or are on the periphery of the system, such as Four Corners or Moss Landing, (Fig. 2d) the frequency differences are relatively large.

Differences in frequency that occur over a wide geographical area may result in minor inequities in load shedding between individual systems in an interconnected area. Also, underfrequency relays located near generator buses will see short-period frequency fluctuations significantly different from those at distribution or transmission buses. See Fig. 2c Hoover 16.5 kV.

The load shedding modeled in the stability study was the load shedding schedule in effect during 1974 in the southwest: 10 percent steps at 59.1 Hz, 58.9 Hz, and 58.6 Hz. In this particular case, when the frequency decayed to 59.1 Hz, 2,363 MW was shed after 0.2 seconds by digital relays and 1,280 MW was shed after 0.4 seconds by electromechanical relays. Due to the differences in frequency at various points in the area, the actual shedding occurred at different times:

New Mexico at approximately 1.96 seconds,
Arizona at approximately 2.03 seconds,
California at approximately 2.2 seconds.

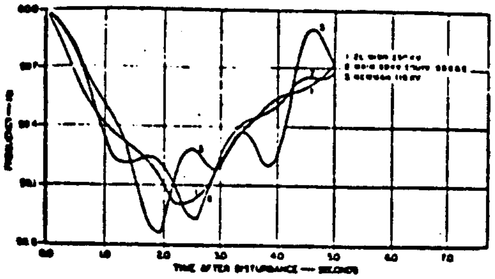


Fig. 2a

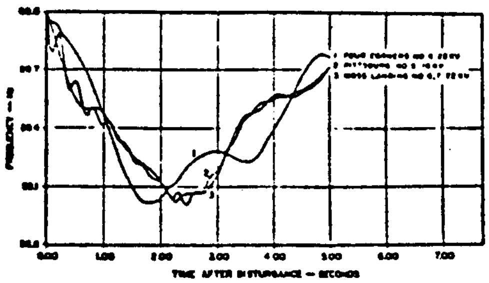


Fig. 2d

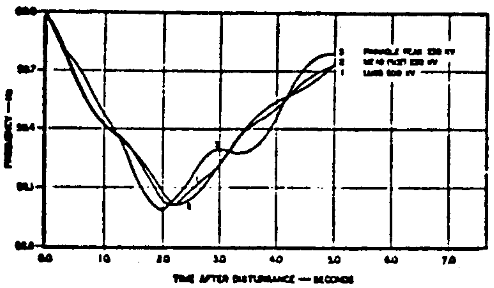


Fig. 2b

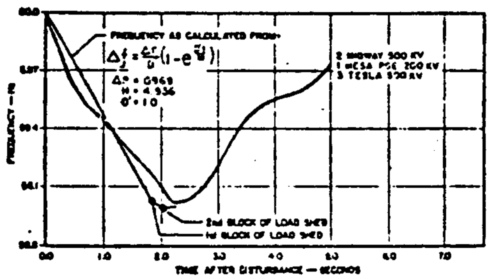


Fig. 2e

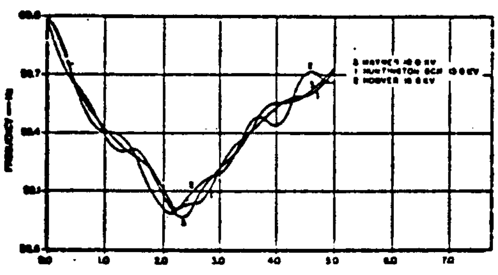


Fig. 2c

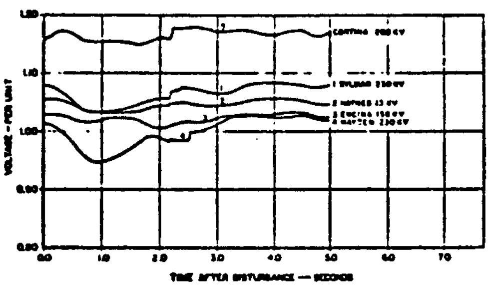


Fig. 2f

Fig. 2 System frequencies and voltages taken from PG&E staff WSCC 1974 Heavy Summer Loading Case with load shedding.
Pre Disturbance Loading:
AC Pacific Intertie 2000 MW N to S
DC Pacific Intertie 1300 MW N to S
Disturbance: Open AC & DC Interties
Subsequent Action:
Open Four Corners - Shiprock 230kV
Open Four Corners - Huntington 345kV
Open Glen Canyon 345/230kV
Shed Load as per 1974 Underfrequency Load Shedding Survey

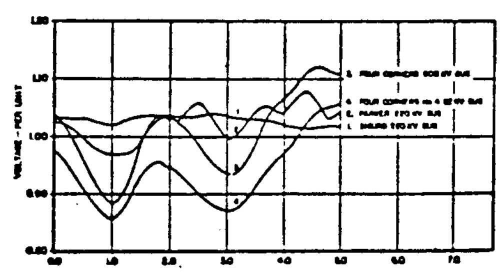


Fig. 2g

Figure 2 shows recovery after load shedding at about 2 seconds. Since the amount shed was only slightly in excess of the generation loss, it appears that governor action was responsible for the rapid recovery and would be expected at about this time.

Figures 2f and 2g show the voltage conditions over the system from this stability study. Two conditions are worth noting in these plots: first, the large voltage changes at Four Corners which would be of concern in coordinating voltage sensitive frequency relays; and second, the voltage rise at Cortina, between 0 and 0.5 seconds, which has an effect on the rate of frequency decay in the area. This increase in voltage increases the resistance component of area load and causes the faster rate of decay that occurs in this area relative to that in other areas where the voltage remains constant or decreases.

The small differences in frequency that occur in the actual system must be recognized but do not prevent the realistic coordination of load shedding programs.

A simple means of predicting the system frequency decay will greatly facilitate the design of load shedding programs. The equation derived in reference 9 for this purpose is as follows:

$$\Delta f = \frac{\Delta P}{D'}\left(1 - e^{\frac{-D't}{M}}\right)$$

Figure 2e illustrates a plot of frequency versus time for a centrally located station, as calculated from the equation and the results from the dynamic stability study case, 1974 HS. The agreement of these curves confirms the usefulness of this equation. In the next section, the system parameters used in this equation will be considered.

B. System Parameters

The basis for applying underfrequency relays is the expected decay of the system frequency following a loss of generation in the system. The geographical area of the system considered may be large, such as the California Power Pool area, or small, such as that of only one operating company within the WSCC area. Regardless of the size, there are certain fundamentals that determine the characteristic decay of frequency.

Frequency excursions sufficiently serious to require underfrequency load shedding are highly unlikely unless preceded by a disturbance that causes a breakup and islanding of the interconnected systems. This has been verified, both historically and by study. To date, all disturbances where the WSCC system remained intact have produced a frequency decline of less than 0.5 Hz. A recent 1978 stability study (Swing Study 78J01) performed by Bonneville Power Administration showed a maximum drop in frequency of 0.53 Hz for the loss of 7,000 MW of generation at Grand Coulee, Hanford, and Chief Joseph. Therefore, the coordination of load shedding schedules between systems can be limited to those groups of systems that will be islanded together after an interconnection breakup.

Certain system parameters are particularly important in determining the frequency decay characteristic, once an islanded system with overloaded generation has been defined:

a) System Inertia Constant, H

The system inertia constant H represents the total kinetic energy of rotation of the generators which are overloaded and hence slowing down under a decelerating torque. The rate of change of speed of the generators is inversely proportional to the constant; i.e., the larger the H constant, the lower will be the rate of decay in speed and frequency for a given overload.

The inertia constant H of a generator is defined as megawatt-seconds per MVA and is calculated from the moment of inertia of the rotating mass of the generator and prime mover, and the generator rating.

The manufacturer's performance specification for a generator includes the H constant and the MVA rating; therefore, the inertia constant for a particular group of generators can be calculated. The H constant of each machine multiplied by the MVA rating gives the megawatt-seconds of inertia of each machine.

An equivalent machine inertia constant can be calculated by totaling the individual machine MW-sec. ratings and dividing by the total of the machine MVA ratings; i.e.,

$$\text{Machine Equivalent H} = \frac{\Sigma\,\text{MW-Sec.}}{\Sigma\,\text{Rated MVA}}$$

The system equivalent H constant is calculated by taking the MW sec. of all spinning machines and dividing by the system base MVA; i.e.,

$$\text{System Equivalent H} = \frac{\Sigma\,\text{MW-Sec. Spinning}}{\text{Base MVA}}$$

where the system base MVA is the total input to the system by the remaining generation.

An approximate system H can be calculated by using the machine equivalent H and correcting this by a ratio of total spinning MVA ratings to load-carrying generation:

System H = Machine Equivalent H times the ratio

$$\frac{\text{Total MVA Spinning}}{\text{Total Load-Carrying Generation}}$$

The inertia of rotating machines such as spinning reserve, motors, and synchronous condensers is included in the total MW-sec. of inertia; but, since these machines do not contribute to the system generation, their MVA ratings are not included in the base quantity. This results in an increase in the effective inertia constant and will have a significant effect on the rate of frequency decay of the system.

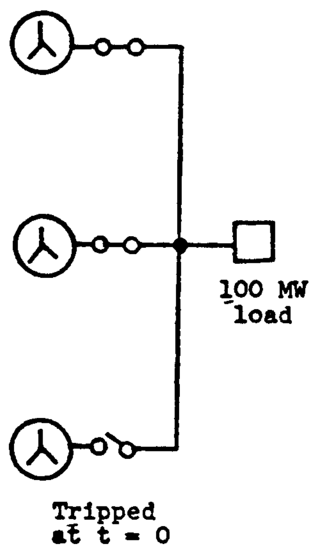
The following examples may help to clarify this concept. Note that the inertia remaining in each case is the same, and hence the rate of decay of frequency will be the same for the same overload.

Example 1)

H = 4
37.5 MVA rating
unloaded

H = 3
50 MVA rating
at 50 MW load

H = 6
50 MVA rating
at 50 MW load



After t = 0

system load = 100 MW

system generation = 50 MW

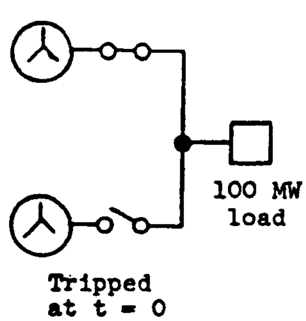
Summing the inertias of the remaining machines and dividing by the MW of remaining generation to obtain the equivalent H constant of the system:

$$\text{Equiv. System H} = \frac{4 \times 37.5 + 3 \times 50}{50} = 6$$

Example 2)

H = 3
100 MVA rating
at 50 MW load

H = 6
100 MVA rating
at 50 MW load



After t = 0

system load = 100 MW

system generation = 50 MW

Again, dividing the inertias of the remaining machines by the MW of remaining generation to obtain the equivalent H constant of the system:

$$\text{Equivalent System H} = \frac{3 \times 100}{50} = 6$$

In Example 1, above, the effect of an unloaded machine is to increase the equivalent system H. This will reduce the rate of decay of frequency as discussed previously. In this example, if the unloaded machine were not connected, the equivalent system H would be 3 rather than 6. The initial rate of decay for the unconnected case would be twice that of the connected case. This illustrates the importance of unloaded machines.

The system equivalent H constant can be calculated to within a few percent accuracy by considering each and every machine in the overloaded area for a specific condition. However, where designing load shedding programs, this accuracy is not generally necessary. For this purpose, it is sufficient to know the machine equivalent H constant in a particular area and the ratio of total spinning machine MVA to load carrying generation in the overloaded area. Then the machine equivalent H for the area multiplied by the ratio will give an approximate value for the equivalent system H for the overloaded area.

The value obtained for the system equivalent H will generally fall in the range 3 to 7; however, individual generating units or those of special design may have a constant considerably higher or lower. For example, in the PG&E system, the H constant for a modern 750 MVA thermal unit is 2.65, and for an older thermal unit it is 10. The equivalent machine H constant for PG&E's total generation is 3.6. The actual constant for the entire southwest, used in the stability study, Case 1974 HS, was 4.96.

b) Overload on Remaining Generation, ΔP

The imbalance of load over generation is the most significant condition that must be considered in determining the expected frequency decay characteristic of the system. This overload is the driving force that causes the system frequency to drop, and it must be reduced to zero to halt the frequency decay. Together with the inertia constant, it directly determines the rate of frequency decline.

The per unit overload is defined by the relation:

$$\Delta P = \frac{\text{Generation - Load}}{\text{Generation}}$$

Note that this definition differs from the equation for ΔP in references 6, 9, and 11. ΔP is defined in this manner so that the sign for ΔP will agree with the accelerating torque equations of reference 11 and also so that the sign of ΔP will be negative for excess load and positive for excess generation. Note that 1.0 per unit overload results from an 0.5 per unit loss of generation as defined here.

By use of these two system constants, H and ΔP, the initial rate of change of frequency can be estimited from the relation:

$$\frac{df}{dt} = \frac{\Delta P}{2H} \qquad 6,\ 9,\ 11$$

where $\frac{df}{dt}$ = per unit rate of change of frequency

ΔP = per unit overload on the remaining generation

H = system inertia constant

Thus, for a 50% or 0.5 per unit overload and a H of 4,

$$\frac{df}{dt} = \frac{-0.5}{2 \times 4} = -0.0625 \text{ per unit/sec}$$

$$-0.0625 \times 60 = -3.75 \text{ Hz/sec}$$

c) Frequency Sensitivity of Load and Generation

The deceleration of the system results from a net imbalance in torques of the input to the generating machines and the torque of the load. If these torques were constant, the decline in frequency would be constant and continue until some control action is taken. However, both the load and generator torques vary with the frequency and result in a natural leveling out of the frequency decline at some lower frequency at which the torques balance. References 6, 9, 11 include discussion and derivation of equations for including these effects.

The load sensitivity is denoted by the symbol d and is the ratio of percent load change to percent frequency change. The value of d = 2 has been used for many years; however, measurements have been made that indicate lower values may be more correct.[9] A value of d = 1.5 has been assumed as reasonable and is used in this guide.

The generator torque varies inversely as the frequency under the assumption that the power output remains constant.

Both of these effects are included in an overall damping factor denoted by D' which is calculated from d and ΔP by the equation:

$$D' = d(1 - \Delta P) + \Delta P$$

The sign of ΔP may be positive or negative; positive for excess generation, negative for excess load.

If underfrequency relaying is applied to operate within the first two seconds following a disturbance, the effect of d is relatively unimportant. If underfrequency relaying takes 4 or 5 seconds to operate, the effect of d is more significant, but its effect may be overshadowed by machine governor action. Note that the constant d affects the per unit overload ΔP more rapidly than it affects the total system load; however, d does not have significant effect until the frequency has decayed appreciably.

The equation which describes the frequency change for an imbalance of load and generation is:

$$\Delta f = \frac{\Delta P}{D'}\left(1 - e^{\frac{-D't}{M}}\right) \qquad 9$$

where Δf = the per unit frequency change from the starting frequency

$\Delta P = \dfrac{\text{Generation - Load}}{\text{Generation}}$

and is negative for overload

$D' = d(1 - \Delta P) + \Delta P$,

the overall damping factor

H = the system inertia constant

M = 2H

This equation can be solved for t to obtain the time required for the frequency to change by Δf.

$$t = \frac{-M}{D'} \ln\left(1 - \frac{D' \Delta f}{\Delta P}\right)$$

The maximum decline in frequency can be estimated from the equation for Δf if t is infinite:

$$\Delta f = \frac{\Delta P}{D'}$$

This equation can be used to calculate the ultimate frequency decline and the change in load by load shedding to limit this decline to some selected amount.

For example, if a system is overloaded 10% or -0.1 per unit and the load sensitivity d = 1.5

$$D' = 1.5\,[\,1 - (-0.1)\,] + (-0.1)$$

$$= 1.55$$

and $\Delta f = -0.1/1.55 = -0.0645$ per unit

or $\Delta f = -0.0645 \times 60 = -3.87$ Hz

for a 60 Hz system.

Also, if a maximum allowable frequency decline is selected, such as 1.6 Hz, the permissible overload can be determined, and hence, the amount of load that must be shed to limit the decline to the selected value.

In this case of 10% overload, if Δf is to be limited to 1.6 Hz or 1.6/60 = 0.0267 per unit and d = 1.5, the required ΔP can be calculated from:

$$\Delta f = \frac{\Delta P}{D'} = \frac{\Delta P}{d\ (1 - \Delta P) + \Delta P}$$

solving for ΔP:

$$\Delta P = \frac{\Delta f\ (d)}{1 + \Delta f\ (d - 1)}$$

$$= \frac{-0.0267\ (1.5)}{1 + (-0.0267)(1.5-1)} = -0.0406 \text{ per unit}$$

ΔP must be less than 0.0406 per unit or reduced to this value from its initial value by shedding load. The load that must be shed to accomplish this is calculated from:

$$\Delta P = \frac{\text{Generation - Load}}{\text{Generation}}$$

For example, in this case, if original load = 11000 MW and generation = 10000 MW, then the original ΔP was

$$\Delta P = \frac{10000-11000}{10000} = -0.1 \text{ per unit.}$$

to obtain the new $\Delta P = -0.0406$

$$-0.0406 = \frac{10000\text{-New Load}}{10000}$$

New load = 10000 + 10000 (.0406) = 10406 so the load that must be shed is 11000 - 10406 = 594 MW.

d) Governor Action

In the time period 0-2 seconds after the disturbance that causes the frequency decay in a system, there is little significant governor action, due to the inherent delays in the mechanical and steam or hydraulic system. This is the period in which load shedding must take action to ensure minimum system disturbance, presuming that the disturbance is large enough to require load shedding to arrest the frequency decay.

In these considerations, governor action is not included and, therefore, this study is confined to the period 0-2 seconds.

VI. UNDERFREQUENCY RELAY CONSIDERATIONS

A. RELAY TYPES

Protective relays used for underfrequency load shedding may be divided into three main types: solid state digital relays, high speed (induction cylinder or cup) electromechanical relays, and low speed (induction disc) electromechanical relays.

a. Solid State Digital Underfrequency Relays

The digital underfrequency relay is an electronic relay which measures frequency accurately. It accomplishes this by counting the number of pulses from an internal crystal controlled oscillator between voltage zero crossings. A trip output is produced if the number of pulses is in excess of the number corresponding to that particular frequency setting. Anything which affects the time between zero voltage crossings such as change of phase angle or harmonics will cause inaccurate measurements. For this reason, the relay design provides for counting pulses over several crossings. An adjustable timer is included to permit additional fixed time. A total of six cycles (0.1 seconds) from the time the system frequency crosses the set point until the relay gives a trip output is the recommended minimum time delay.

Digital relays are easy to apply because they are stable and predictable in their response. The set point of a digital relay may be expected to remain within 0.005 Hz over a voltage range of of approximately 50 to 130 volts and a temperature range of -20 C to +60 C.

Since the trip time after reaching the relay setting is independent of the rate of decline of the system frequency, the trip time is predictable under dynamic system conditions. See Figure 3.

Digital relays however, are complex electronic devices with hundreds of components and are more subject to internal malfunction which will prevent the relay from tripping than are electromechanical relays. Failures in certain circuits can also cause false trip outputs.

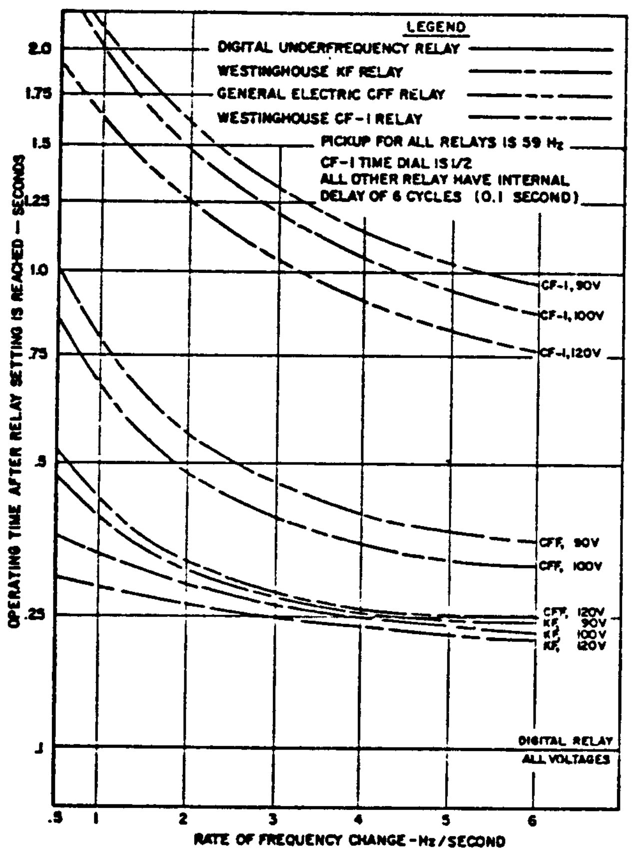


Fig. 3 Operating time for various underfrequency relays as a function of voltage and rate of frequency change.

b. High Speed Electromechanical Underfrequency Relays

The high speed electromechanical underfrequency relay employes induction cup or induction cylinder design and is normally adjustable over a frequency range of 54.0 to 59.5 Hz. The accuracy of the frequency setting is a function of voltage and temperature. The relay trip time after the frequency setting is reached is a function of voltage and rate of change of frequency. This is illustrated in Figure 3.

To overcome undesirable operations due to mechanical shock, voltage dips, or other system transient conditions, a minimum time delay of 6 cycles (0.1 sec.) is recommended.

The high speed electromechanical underfrequency relay has been used successfully in load shedding programs for over 15 years. It can continue to provide satisfactory service if the above characteristics are taken into consideration. However, its use is not recommended for new installations because of the complexity of application.

c. Low Speed Electromechanical Underfrequency Relays

Induction disc underfrequency relays have been applied for years and are still in service in many locations. However, they are slow, the operating time is a function of rate of change of frequency, they are voltage sensitive and some of them are sensitive to temperature. It is not possible to coordinate these relays with high-speed electromechanical relays or solid state digital relays. With a frequency setting of 59 Hz and time lever 1/2, the CF-1 relay operating time varies between 0.75 seconds and 1.9 seconds with rates of frequency decay between 6 Hz/second and 0.5 Hz/second. See Figure 3.

Past performance has proved that these relays will shed load and preserve islanded systems consisting of hydro and older steam plants. The addition of new equipment including gas turbines, modern steam turbines, and nuclear plants, which are more sensitive to underfrequency conditions, makes high speed load shedding imperative. Therefore, induction disc relays should be replaced in areas where unnecessary loss of generation facilities could be prevented by shedding load sooner, or when coordination with high-speed relays is necessary.

B. RELAY RELIABILITY

In any load shedding program there is a conflict between the requirements of the two elements of reliability: security and dependability. The configuration of the system, the size and type of load being shed, and the method of shedding the load are important determining factors in security versus dependability considerations.

Where critical loads are to be shed, one practice has been to use two relays in series to improve security. Improved security is achieved at the expense of reduced dependability but this is justifiable when there are several relay installations shedding blocks of load at each frequency. If two digital relays are to be used in series, maximum security may be obtained by using relays of different design. If an electromechanical relay is used in series with a digital relay, the electromechanical relay should be set sufficiently above the digital relay setting to permit the digital relay to control the tripping.

Where the loads being shed are of a less critical nature, particularly industrial loads where interruptable contracts prevail, security usually becomes a secondary consideration to dependability. This is particularly true where a single large load is being shed which may be a major portion of the particular utility's load shedding program. Failure to shed this one load may result in a system black-out while an unnecessary outage to the customer may cause no significant loss. In this case dependability and accuracy are primary factors which would indicate the use of a single digital relay, or two digital relays of different design connected in parallel.

Security and dependability are both magnified when the load being shed by a single relay installation is a major portion of the total load shedding program and no discrimination has been possible as to the critical nature of the aggregate parts of the load to be shed. These conditions will exist when load shedding is accomplished by tripping a radial transmission line to which several distribution substations are connected. In these cases it may be desirable to improve security and dependability by the use of three underfrequency relays with their three outputs connected in a matrix such that any two trip outputs will result in load shedding.

Incorrect tripping can occur from any of the above relay systems when the voltage source connected to the underfrequency relays is subject to decelerating motor load or other conditions which generate false low frequency voltages. Where this condition exists, a high dropout voltage relay connected to the underfrequency relay voltage source or a current relay connected to the source current transformers may be used to supervise the trip output of the underfrequency relays.

When two or more high speed electromechanical relays are used for security, separate voltage sources should be used to prevent misoperation on loss of voltage.

C. RELAY COORDINATION

Underfrequency excursions below 59.5 Hz are not likely to occur on the WSCC System as long as the system remains intact. Coordination plans can therefore be limited to those groups of systems that will be islanded together following a disturbance and inter-connection breakup. The probable configurations of the islands can be determined from historical breakup data. Computer studies can and should be used to determine future breakup patterns as the WSCC System grows in order to keep the load shedding plans current.

C. RELAY COORDINATION (Continued)

Coordination as used here has a different meaning from that used in protective relaying. As used here, coordination means that for a maximum assumed overload, only those load blocks are dropped that are necessary to arrest the frequency decay before the minimum permissible frequency is reached. An example of this type of coordination is given in the sample problem in the Appendix.

The burden of load shedding should be borne equitably by the utilities that are islanded together. This means that at any given frequency during a frequency decay, each utility should have shed approximately the same percent of its load. Plots of percent load shed by each islanded utility versus frequency for various frequency decay rates will indicate the equitability of the load shedding plan.

Within each given area where a load shedding program is implemented, coordination with underfrequency relays on generators is vital. The best of load shedding programs are useless unless they are coordinated with the underfrequency protection of the generating unit. Some steam and gas turbines have limited capability in operation at reduced speed and are sometimes equipped with underfrequency relays.[13] If proper coordination is not attained between underfrequency load shedding and generator underfrequency dropping, generation will be dropped at a very critical time with possible disastrous results to the system. If further load shedding is required at frequencies below underfrequency generator dropping, sufficient load must be also simultaneously shed to compensate for the loss of generation dropped. A much better solution is to complete all load shedding at frequencies well above generator drop frequencies. This will minimize the amount of load shedding required.

The type of underfrequency relays used by the islanded utilities will affect both the maximum overload for which coordination can be achieved and the equitableness of the load shedding plan. The exclusive use of digital relays offers, at this time, the best means of achieving coordination under most overload conditions and for achieving equitableness. The use of digital relays will also make setting up a load shedding plan easier since the trip time is constant. The exclusive use of electromechanical high speed relays or a mixture of digital relays and electromechanical high speed relays can be used, but there are some inherent difficulties. The setting of the electromechanical relays varies with voltage and temperature producing a range of uncertainty which must be accounted for in the load shedding plan. Electromechanical relays have slower trip times than digital relays and the trip time is different for different frequency decay rates. See Figure 3. For an assumed overload and resulting frequency decay, electromechanical relays must be set higher than digital relays in order to have the same operating point. See Figure 4. For lower frequency decay rates, the higher set electromechanical relays will operate first resulting in inequitable load shedding.

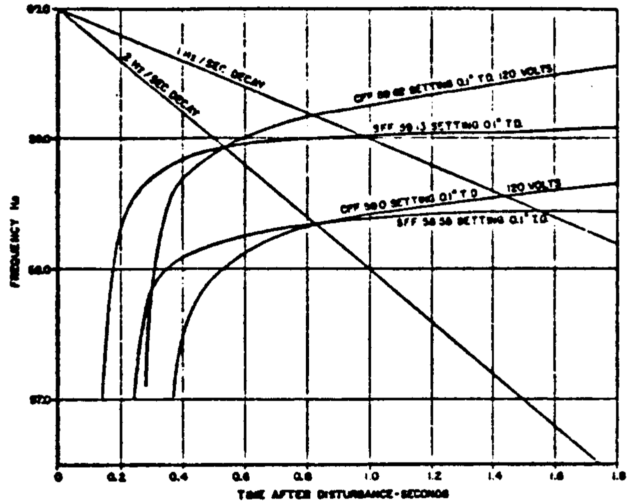


Fig. 4 Time to operate after start of frequency decline for digital SFF relays and electromechanical CFF relays with various settings -- illustrates difficulty of coordination with mixed relay types.

D. LOAD RESTORATION

After sufficient load has been shed to arrest the decay in system frequency by balancing load and generation, the frequency will begin to recover to 60 Hz by governor action on spinning reserve generation or by the addition of other generation. This recovery will be much slower than the decay and may extend over several minutes.

As the frequency recovers toward 60 Hz, the load that has been shed may be restored manually or automatically but only to the extent that generation and load remain balanced. Continued recovering toward 60 Hz is a necessary condition before additional load can be restored.

The size of the blocks of load shed, the availability of remote control or station operators, the number of stations at which load shedding is done, and the suitability of the frequency relays for automatically restoring load are all factors that must be considered in planning a load restoration system.

If the blocks of load being restored are large, such as 2 to 3 percent of the total system load, the frequency at which they are restored must be higher and the time between restoration steps longer than if the blocks of load are smaller.

If full supervisory control or station operators are available at load shedding stations, then manual restoration is practicable, but even in these cases automatic restoration may be justified.

D. LOAD RESTORATION (Continued)

If the total load is shed in only a few large blocks, considerable care must be taken in selecting the time and frequency at which the blocks are restored to ensure that the frequency continues to recover toward 60 Hz. If the load is shed in many smaller blocks, then there is less risk in automatic restoration since there is a built-in diversity in timing of equipment; however, additional restoration time delay may also be desirable.

The frequency relays used for a combined shedding and restoration program should have independent outputs for shedding and restoration. This will permit different frequency settings for the two functions and allow close control of both actions.

When the load shedding is accomplished by tripping distribution feeders, it is possible to include automatic restoration by frequency control of the reclosing relays.

VII. DETERMINATION OF RELAY SETTINGS

The determination of relay settings for an underfrequency load shedding program should begin with a review of system conditions. The first step is to determine the maximum loss of generation to be designed for, the system load and spinning MVA at the time of this overload, the minimum frequency to be permitted and the number and size of load shedding steps. Second, relay settings are then calculated so that a minimum of load may be shed for light overloads and and yet the most severe overload can be relieved before reaching the minimum permissible frequency.

The number and size of load shedding steps is a function of the amount of load to be shed and the frequency range between the highest frequency which may be used for load shedding and the minimum permissible frequency. Experience has shown that three to five load shedding steps will provide coordination. The actual number and size of the steps is somewhat arbitrary. In the example in the Appendix, three steps of 10 percent, 10 percent, and 15 percent were chosen but other combinations totaling approximately 35 percent could have been used. The load shed at each step should be distributed over a number of locations on the system to minimize power swings or overloading transmission facilities.

The frequency of the first load shedding step for firm loads should be below any frequency from which the system could recover without dropping load and without damaging equipment. Most load shedding programs use a frequency of 59.0 to 59.4 Hz for the first step because steam turbines can operate continuously at a frequency of 59.4 Hz. and up to 90 minutes at 58.8 Hz. However, gas turbines and nuclear plants may have more stringent frequency requirements.

The setting of the next load shedding step is chosen at a low enough frequency to prevent its operation for overload conditions that could have been relieved by the operation of the first step. In the example in the Appendix, the first load shedding step consists of shedding 10 percent of the system load at a relay setting of 59.1 Hz. Because of time delays, however, the circuit breaker will not open until the frequency has declined to 59.02 Hz. Obviously, the next step should be below 59.02 Hz with some coordinating margin.

Frequency oscillations of 0.1 Hz are not unusual on an overloaded system and frequency differences of 0.25 Hz between various buses have been reported. (Figures 1 and 2) Therefore, it is desirable to have at least 0.1 Hz margin between the frequency at which the circuit breaker opens for one step and the setting of the next load shedding relay.

The relay setting of the second step should also be low enough to provide coordinating margin so that overloads slightly above the load shed in step one can be relieved by the load sensitivity factor without shedding additional load. For instance, in the example in the Appendix, the first step of load shedding is 10 percent at 59.1 Hz and the second step frequency setting is at 58.9 Hz. The overload that corresponds to a "settle out" frequency at 58.9 Hz is 2.77 percent. When this is mathematically combined with the 10 percent load shed by the 59.1 Hz step it results in a 14.5 percent overload. In other words, if the system experiences a 14.5 percent overload, and 10 percent of the load is shed, the system frequency will not go below 58.9 Hz, so no additional load should be shed.

The last load shedding step must also have some coordinating margin to assure that the circuit breaker is open before the frequency goes below the minimum permissible frequency.

A detailed example of a load shedding calculation is included in the Appendix.

VIII REFERENCES

1. Lokay, H.E., and Burtnyk, V., "Application of Underfrequency Relays for Automatic Load Shedding," IEEE PAS, Vol. 87, No. 3, March 1968, pp 776-783.

2. Fountain, L. L., and Blackburn, J. L., "Application and Test of Frequency Relays for Load Shedding," AIEE Trans. PAS, Vol. 73, February 1955, pp 1, 660-1, 664.

3. Maliszewski, R. M., Dunlop, R. D., and Wilson, G. L., "Frequency Actuated Load Shedding and Restoration, Part I: Philosophy, "IEEE PAS-90 No. 4, July/August 1971, pp 1,452-1, 459.

4. Horowitz, S. H., Politis, A., and Gabrielle, A. F. "Frequency Actuated Load Shedding and Restoration, Part II: Implementation, "IEEE PAS, Vol. 90, No. 4, July/August 1971, pp 1,460-1,468.

5. IEEE Committee Report, "The Effect of Frequency and Voltage on Power System Load," presented at the IEEE Winter Power Meeting, New York, New York, January 30 through February 4, 1966.

6. Dalziel, C. F., and Steinbach, E. W., "Underfrequency Protection of Power Systems for System Relief, Load Shedding-System Splitting, " AIEE Transactions PAS, Vol. 78, December 1959, pp 1,227-1,238.

7. Crary, Selden B., Power System Stability, Vol. II, Transient Stability, (New York, John Wiley & Sons, Inc., 1947).

8. Bauman, H. A., Hahn, G. R., and Metcalf, C.N. "The Effect of Frequency Reduction on Plant Capacity and on System Operation," AIEE Transactions PAS, Vol. 74, pp 1,632-1,637.

9. Berry, Brown, Redmond, and Watson, "Underfrequency Protection of the Ontario Hydro System, " 1970, Cigre Paper 32-14.

10. IEEE Committee Report, "Survey of Underfrequency Relay Tripping of Load Under Emergency Conditions," IEEE PAS, Vol. 87 No. 5, May 1968, pp, 1362-1,366.

11. Berdy, J., "Load Shedding Application Guide," General Electric Trans 1968.

12. "Panel on Load Shedding and Bail-Out Frequencies, " EEI System Planning Committee, February 13-14, 1969, Remarks by C. Concordia, General Electric Company, Schenectady, New York.

13. Berdy, J., Brown, P. G., and Goff, L. E., "Protection of Steam Generators During Abnormal Frequency Conditions", 1974 Conference for Protective Relay Engineers, Texas A&M University.

IX APPENDIX

SAMPLE CALCULATION OF RELAY SETTINGS

Assume the requirement is to design a load shedding scheme for a group of companies in an operating pool.

It is required to shed enough load, based upon the most pessimistic loss of generation expected for the pool, to prevent the frequency deteriorating to a value below a minimum permissible frequency.

DATA GIVEN

Maximum pool load	= 20000 MW
Minimum pool load	= 10000 MW
Equiv. Mach. Inertia Const. H	= 4.0
Spinning MVA (Maximum System)	= 25000 MVA
Spinning MVA (Minimum System)	= 17000 MVA
Load sensitivity factor d	= 1.5
Minimum permissible frequency	= 58.4 Hz
Generation Lost	= 3333 MW
Spinning MVA Lost	= 5000 MVA

PRELIMINARY CALCULATIONS

As pointed out in the section on system parameters, the inertia constant H determines the initial rate of decline of frequency for a given overload, and that rotating unloaded machines tend to increase this inertia constant. The H constant given in the data would be modified by the ratio of the spinning MVA divided by the system MW. This results in an Equivalent System H for the minimum system of:

$$\text{Equiv. Min. System H} = \frac{4 \times (17000-5000)}{(10000-3333)} = \frac{4 \times 12000}{6667} = 7.2$$

and an Equivalent System H for the maximum system of:

$$\text{Equiv. Max. System H} = \frac{4 \times (25000-5000)}{(20000-3333)} = \frac{4 \times 20000}{16667} = 4.8$$

To determine the worst case it is necessary to look at both the minimum and maximum system.

The overload for the minimum system would be:

$$\Delta P = \frac{-3333}{6667} = -0.5 \text{ per unit}$$

H (Minimum system) = 7.2

The initial rate of frequency decline is:

$$\frac{df}{dt} = \frac{\Delta P}{2H} = \frac{-0.5}{14.4} = -0.0347 \text{ per unit/sec}$$

$$-0.0347 \times 60 = -2.08 \text{ Hz/sec}$$

The overload for the maximum system would be:

$$\Delta P = \frac{-3333}{16667} = -0.2 \text{ per unit}$$

H (Maximum system) = 4.8

The initial rate of frequency decline is:

$$\frac{df}{dt} = \frac{\Delta P}{2H} = \frac{-0.2}{9.6} = -0.0208 \text{ per unit/sec}$$

$$-0.0208 \times 60 = -1.25 \text{ Hz/sec.}$$

Since the 2.08 Hz/sec. rate of frequency decline for the minimum system is the worst case, the balance of this example will be based upon this minimum system.

While it is theoretically possible to take advantage of the load sensitivity factor to arrest the frequency decline without shedding a full 33 percent of the load, the more conservative approach is recommended. For this example, assume that 35 percent of the load is to be shed.

Also assume all load is to be shed with digital underfrequency relays with a time delay of 0.1 second and a circuit breaker time of 0.1 second (total time of 0.2 second).

Since the overload must be relieved before the frequency decays to 58.4 Hz, it appears that a three-step load shedding scheme will be required to allow time for coordination between steps. For a first trial the three steps will be 10 percent, 10 percent, and 15 percent of the load.

The frequency of the first step should be as low as possible consistent with the requirement of protecting generating equipment and shedding 35 percent of the load prior to the system frequency reaching 58.4 Hz.

Several methods have been described in the literature for obtaining the plot of the system frequency decline under overload conditions, 1, 2, 11. Also these dynamic system curves may be obtained from computer studies. (Figure 2). This example describes a simple graphic solution followed by a mathematical solution.

GRAPHICAL SOLUTION

Figure 5 depicts the rate of change of frequency vs overload for a load sensitivity d of 1.5 for a range of frequencies from 54 to 60 Hz. Using Figure 5 construct a set of curves, in three steps. (Figure 6). These curves represent the dynamic system frequency decline for three overloads, corresponding to the three steps selected above. This is necessary to determine that coordination is obtained between steps.

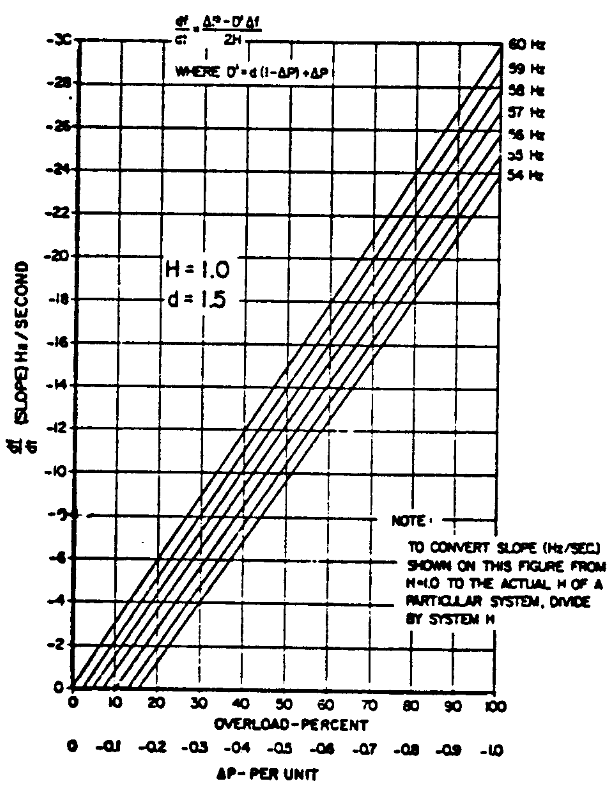


Fig. 5 Frequency rate of change due to system overload.

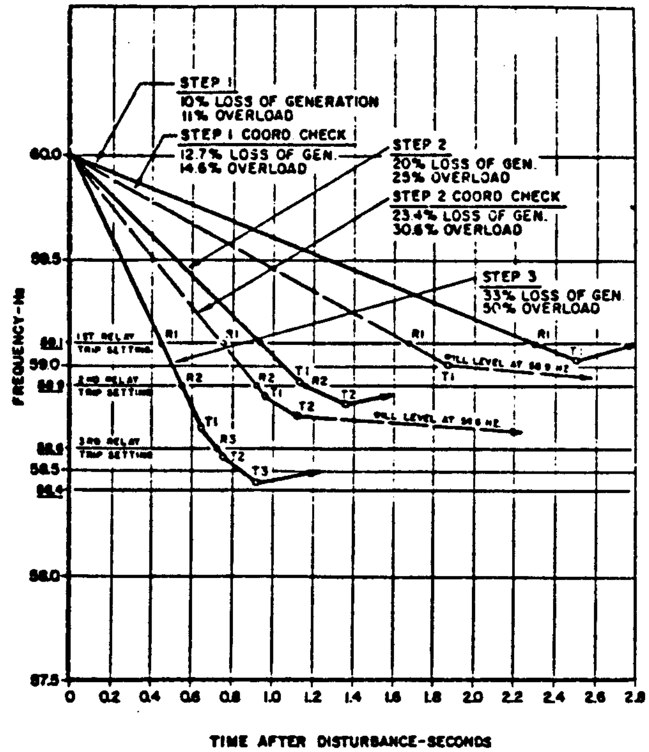


Fig. 6 Frequency decline due to system overload - determined graphically

For simplicity, it is assumed that the ratio of MVA of spinning machines remaining on the system after the disturbance divided by the MW of load carrying generation remaining on the system after the disturbance

$$\frac{\text{MVA spinning after disturbance}}{\text{MW generating after disturbance}}$$

is constant for the various overload conditions calculated in this example. This results in an equivalent system H of 7.2 for each of the overloads studied.

This assumption is valid for an isolated system where the generation lost consists one or more partially loaded generating plants.

If the overload is caused by a system being islanded that had been importing power, then the spinning MVA remaining on the islanded system after the disturbance would be constant and the system H would be different for the different overloads.

Step No. 1

For a first approximation, assume that the first step of load shedding will be 10 percent of the load at 59.1 Hz. The first step of the solution is to draw an overload curve equivalent to a 10 percent loss of generation to find the actual frequency at which the circuit breaker will open.

10000 MW System
\- 1000 MW of Generation Lost
9000 MW of Generation Remaining

$$\Delta P = \frac{-1000}{9000} = -0.11 \text{ per unit}$$

GRAPHICAL SOLUTON (Continued)

Using the data given, a curve similar to Figure 6 may be produced in the following manner:

Enter Figure 5 at 0.11 per unit overload and read 3.2 Hz/second rate of frequency change from the 60 Hz curve, and 2.4 Hz/ second from the 59 Hz curve for H = 1, and d = 1.5. This is an approximate solution using straight lines so use an average of 2.8 Hz/ second.

In this example the system H was 7.2, so the actual slope = 2.8/7.2 = 0.39 Hz/second. Draw a line, as shown on Figure 6, (Step 1) with a slope of 0.39 Hz/second and locate the relay frequency setting R1 at 59.1 Hz and T1 when the circuit breaker trips 0.2 seconds later. The system frequency when this circuit breaker opens is 59.02 Hz. To provide coordination between steps, the second step should be at least 0.1 Hz lower. Therefore, assume a relay setting for step two of 58.9 Hz.

Step No. 2

Draw an overload curve equivalent to a 20 percent loss of generation to find the actual frequency at which the second step circuit breakers open.

10000 MW System
\- 2000 MW of Generation Lost
8000 MW of Generation Remaining

$$\Delta P = \frac{-2000}{8000} = -0.25 \text{ per unit}$$

Enter Figure 5 at 0.25 per unit overload and read 7.5 Hz/second rate of frequency change for the 60 Hz curve and read 6.6 Hz/second from 59 Hz curve. The average slope = 7.0 Hz/ second.

The actual slope for this system = 7.0/7.2 = 0.97 Hz/second. Locate R1 at 59.1 Hz and T1 when the first circuit breakers trip 0.2 seconds later. This operation results in the shedding of 10 percent of the load or 1000 MW. The per unit overload is now:

$$\Delta P = \frac{-1000}{8000} = -0.125 \text{ per unit}$$

Enter Figure 5 at 0.125 per unit overload and read 2.8 Hz/second rate of frequency change from the 59 Hz curve. (Actually, the slope required is the average of 58.9 Hz and 58.8 Hz. However, an examination of Figure 5 reveals that the slope cannot be read closer than 59.0 Hz.) The slope for this system equals 2.8/7.2 = 0.39 Hz/second. Draw a line as shown on Figure 6, (Step 2) starting at T1 with a new slope of 0.39 Hz/second. Locate R2 at the assumed 58.9 Hz and T2 when the second circuit breakers trip 0.2 seconds later. The system frequency when the second step of load shedding occurs is 58.82 Hz. Since the next load shedding step R3, is to occur at least 0.1 Hz lower, assume the setting for the third step will be 58.6 Hz.

Step No. 3

Draw an overload curve for a 33 percent loss of generation to find the actual frequency that the third step circuit breakers open.

10000 MW System
-3333 MW of Generation Lost
6667 MW of Generation Remaining

$$\Delta P = \frac{-3333}{6667} = -0.5 \text{ per unit}$$

Enter Figure 5 at 0.50 per unit overload and read 15.0 Hz/second rate of frequency change from the 60 Hz curve and 14.0 Hz/second from the 59 Hz curve. The average slope equals 14.5 Hz/second. The actual slope for this system is 14.5/7.2 = 2.01 Hz/second. Draw a line with a slope of 2.01 Hz/second and locate R1 at 59.1 Hz and T1 0.2 seconds later when the first circuit breakers opens. This operation results in the shedding of 10 percent of the load or 1000 MW. The new per unit overload is now:

$$\Delta P = \frac{-2333}{6667} = -0.35 \text{ per unit}$$

Enter Figure 5 at 0.35 per unit overload and read 9.3 Hz/second rate of frequency change from the 58.5 Hz curve. The actual slope for this system equals 9.3/7.2 = 1.29 Hz/second. Draw a line starting at T1 with a slope of 1.29 Hz/second and locate R2 at 58.9 Hz and T2 0.2 seconds later. This operation results in the shedding of an additional 10 percent or 1000 MW. The new overload is:

$$\Delta P = \frac{-1333}{6667} = -0.2 \text{ per unit}$$

Enter Figure 5 at 0.20 per unit overload and read 4.6 Hz/second rate of change from 58.5 Hz curve. The actual slope for this system equals 4.6/7.2 = 0.64 Hz/second. Draw a line starting at T2 with a slope of 0.64 Hz/second. Locate R3 at the assumed frequency of 58.6 Hz and T3 0.2 seconds later. This operation results in the shedding of an additional 15 percent load, so the generation slightly exceeds the remaining load and the system will recover to 60 Hz. The system frequency at which this third set of circuit breakers opens is 58.44 Hz. This meets the criteria that was set, namely to shed enough load to recover from a 33 percent loss of generation before the frequency declined to 58.4 Hz.

In summary, for a 50 percent overload the relays will operate at 0.45 seconds, 0.54 seconds, and 0.72 seconds respectively after the loss of generation, with load shed at 0.65 seconds or 58.69 Hz, 0.74 seconds or 58.56 Hz, and 0.92 seconds or 58.44 Hz.

COORDINATION BETWEEN STEPS

An examination of the curves just produced reveals that the frequency difference between the frequency trip point of one step and the relay set point of the next step is as follows:

Step 1 T1 to R2 = 59.02 Hz - 58.90 Hz = 0.12 Hz

Step 2 T2 to R3 = 58.82 Hz - 58.60 Hz = 0.22 Hz

Step 3 T3 to 58.4 Hz = 58.44 Hz -58.4 Hz = .04 Hz

COORDINATION BETWEEN STEPS (Continued)

The requirement of 0.1 Hz between steps 1 and 2 and between steps 2 and 3 is satisfied, so a check should be made to see if the overload for a "settle out" frequency of 58.9 Hz is relieved before the second step trips. (See section VI)

The overload that corresponds to a "settle out" frequency of 58.9 Hz is obtained by the equation:

$$\Delta P = \frac{d\ \Delta f}{1 - \Delta f + d\ \Delta f}$$

which is derived from the equation

$$\Delta f = \frac{\Delta P}{D'}$$

developed in section VB)c).

where ΔP is the per unit overload defined in section V B) b)

$$\Delta P = \frac{\text{Generation - Load}}{\text{Generation}}$$

ΔP can also be expressed in terms of the load and the generation lost by expressing the generation remaining as total generation minus the generation lost and then substituting load for total generation.

This manipulation will result in a variation of the equation for ΔP:

$$\Delta P = \frac{-\text{ Generation Lost}}{\text{Load - Generation Lost}}$$

By combining this equation for ΔP and the equation for ΔP in terms of Δf and D', above, a new equation, relating generation lost, frequency change, load sensitivity, and load can be derived.

$$\text{Generation Lost} = \frac{d\ \Delta f\ (\text{Load})}{\Delta f - 1}$$

This is the generation loss that will produce a settle-out frequency change, Δf.

The amount of load shed permits the loss of an equal amount of generation without exceeding the frequency change Δf, and should be added to this calculated value.

$$\text{Generation Lost} = \frac{d\ \Delta f\ \text{Load}}{\Delta f - 1} + \text{Load shed}$$

For the first step coordination check:

$d = 1.5$
Δf = -1.1 Hz or -0.0183 per unit
Load = 10000 MW or 1.0 per unit
Load shed = 1000 MW or 0.1 per unit at 59.1 Hz

$$\text{Generation Lost} = \frac{1.5\ (-0.0183)(1.0)}{(-0.0183) - 1} + 0.1 = 0.127 \text{ per unit}$$

The corresponding ΔF can be calculated from

$$\Delta P = \frac{-\text{ Generation Lost}}{\text{Load-Generation Lost}} = \frac{-0.127}{1-0.127} = -0.146$$

A 0.146 per unit initial overload results in an average initial frequency decay of 3.9/7.2 = 0.54 Hz/second and is plotted on Figure 6.

With a 0.146 per unit overload, the first step of load will be shed at 58.99 Hz. This is well above the 58.9 Hz setting of the second step.

Performing the same check between step 2 and step 3:

Δf for 58.6 = -1.4 Hz = -0.0233 per unit

Load = 10000 MW or 1.0 per unit
Load shed = 2000 MW or 0.2 per unit at 58.6 Hz

$$\text{Generation Lost} = \frac{1.5\ (-0.0233)\ (1.0)}{(-0.0233)-1} + 0.2$$

Generation Lost = 0.2342 per unit

and

$$\Delta P = \frac{-0.2342}{1.0 - (0.2342)} = -0.306$$

This overload (as shown in Figure 6) results in the first step of load being shed at 58.86 Hz and a second step of load shed at 58.76 Hz. This is well above the 58.6 Hz relay setting of the third step.

OPTIMIZING SETTINGS

Since there is no conflict between the various steps, consideration may be given to optimizing the settings.

The 0.22 Hz between step 2 T2 and R3 is slightly more than necessary and the 0.04 Hz between step 3 T3 and 58.40 Hz is a little less than desired.

There are four alternatives which should be considered.

1. Accept these results as satisfactory based upon the facts that the solution is approximate, uses estimated data, and represents an idealized situation.

2. Optimize the results by setting R2 at 58.88 and R3 at 58.56 Hz. This provides approximately 0.14 Hz coordinating margin between the frequency trip point of one step and the relay set point of the next step.

   These relay settings will permit a slight additional time delay in the relay to provide additional security if desired, but at the cost of a portion of the 0.14 Hz coordinating margin.

OPTIMIZING SETTINGS (Continued)

3. Repeat the above procedure, starting at 59.0 Hz for the first step. This would reduce the coordination margin between steps; but permit a lower setting for the first step.

4. Repeat the above procedure, starting at 59.1 Hz or higher, using four load shedding steps.

This study was based upon the use of digital underfrequency load shedding relays. If high speed electromechanical relays are used, the operating times become much longer as shown in Figure 3, and the first step may have to be raised to a considerably higher setting or the load may have to be shed in two steps in order to complete the necessary load shedding before reaching 58.4 Hz.

Slow speed electromechanical relays are not suitable for use in this type of load shedding program because of their excessive and indeterminate operating times.

DERIVATION OF FIGURE 5

The curves shown in Figure 5 were derived by using the fundamental equation:

$$\frac{df}{dt} = \frac{\Delta P - D'\Delta f}{2H} \quad 11$$

where ΔP = per unit overload on remaining generation

$D' = d\,(1 - \Delta P) + \Delta P$

Δf = per unit frequency change

For ΔP = -1.0 per unit

$D' = d\,(1-\Delta P) + \Delta P = 1.5\,[(1-(-1.0)] + (-1.0)$

$= 1.5 \times 2 - 1.0 = 2.0$

$$\frac{df}{dt} = \frac{\Delta P - D'\Delta f}{2H} = \frac{-1.0 - 2.0\,\Delta f}{2}$$

$= -0.5 - \Delta f$

Freq.	Δ f (per unit)	$\frac{df}{dt}$ (per unit/sec)	$\frac{df}{dt}$ (Hz/sec)
60	0.0000	-0.5000	-30.00
59	-0.0167	-0.4833	-29.00
58	-0.0333	-0.4666	-28.00
57	-0.0500	-0.4500	-27.00
56	-0.0567	-0.4333	-26.00
55	-0.0833	-0.4166	-25.00
54	-0.1000	-0.4000	-24.00

For ΔP = -0.20 per unit

$D' = d\,(1-\Delta P) + \Delta P = 1.5\,[1-(-0.20)] + (-0.20)$

$= 1.5 \times 1.2 - 0.20 = 1.6$

$$\frac{df}{dt} = \frac{\Delta P - D'\,\Delta f}{2H} = \frac{-0.2 - 1.6\Delta f}{2}$$

$= -0.1 \quad -0.8\Delta f$

Freq.	$0.8\Delta f$ (per unit)	$\frac{df}{dt}$ (per unit/sec)	$\frac{df}{dt}$ (Hz/sec)
60	0.0000	-0.1000	-6.00
59	-0.0133	-0.0867	-5.20
58	-0.0266	-0.0734	-4.40
57	-0.0400	-0.0600	-3.60
56	-0.0533	-0.0467	-2.80
55	-0.0667	-0.0333	-2.00
54	-0.0800	-0.0200	-1.20

ANALYTICAL SOLUTION

In this solution, the equations discussed under Section V B, System Parameters, are used to determine a trial load shedding schedule and the expected system frequency decay curve when this schedule is implemented. This decay curve is then compared with the intended results and, if necessary, adjustments are made to the schedule and the calculations repeated until the desired results are obtained. In this example, the calculations are made once and the results compared with the previous graphical solution.

1) The minimum system is selected as the worst case that must be solved since it has the highest rate of frequency decay. The conditions in this minimum system are as follows:

   Load = 10000 MW
   Generation = 6666 MW
   Load sensitivity factor = 1.5
   Equivalent System Inertia Constant H = 7.2

   From this, ΔP and D' are calculated:

   $$\Delta P = \frac{\text{Generation - Load}}{\text{Generation}}$$

   $$\Delta P = \frac{6666-10000}{6666} = -0.5$$

   $D' = d(1 - \Delta P) + \Delta P$

   $= 1.5\,(1 + 0.5) - 0.5 = 1.75$

2) The minimum amount of load that must be shed to ensure that the frequency decay does not exceed 1.6 Hz can be calculated from the equation for frequency change:

   $$\Delta f = \frac{\Delta P}{D'}\left(1 - e^{\frac{-D't}{M}}\right)$$

ANALYTICAL SOLUTION (Continued)

If t is infinite;

Then, $\Delta f = \frac{\Delta P}{D'}$

and the necessary value of ΔP may be calculated for a given value of D' and Δf.
These values are D' = 1.75, and Δf = -1.6 Hz = -0.0267 per unit

$$\Delta P = \Delta f \; (D')$$

$$= -0.0267\,(1.75) = -0.0467 \text{ per unit}$$

Therefore, the original overload, -0.5 per unit, must be reduced to -0.0467 per unit to limit the frequency decay to 1.6 Hz.

$$(-0.5) - (-0.0467) = -0.4533 \text{ per unit}$$

or, multiplying by the base, 6666 MW, gives 3020 MW.
This means that of the original load of 10000 MW, no less than 3020 MW or 30.2% must be shed. A more conservative estimate would be 35% and is recommended. A trial schedule of 10%, 10%, and 15% will satisfy this requirement.

3) The time for the frequency to drop from 60 Hz to the minimum permissible level, 58.4 Hz, can be estimated from the initial rate of decay that is calculated from the equation,

$$\frac{df}{dt} = \frac{\Delta P}{2H} = \frac{-0.5}{2 \times 7.2} = 0.0347 \text{ pu}$$

$$0.0347 \times 60 = 2.08 \text{ Hz/sec}$$

If no load is shed, the frequency will reach 58.4 Hz in

$$\frac{1.6 \text{ Hz}}{2.08 \text{ Hz/sec}} = 0.77 \text{ sec}$$

Within this period of time, the relays and breakers must operate, shedding load and arresting the decay in frequency.

A minimum time delay setting on the relay will allow maximum separation of the frequency settings of each step and a lower first step while limiting the decay to 1.6 Hz. A greater time delay setting will reduce the frequency separation of the three steps and also raise the setting of the first step.

For the trial schedule, assume that the relay will be set for the minimum time delay, 0.1 second, and allow 0.1 second for the operation of auxiliary relays and power circuit breaker of each step:

1000 MW at 59.1 Hz + 0.2 seconds
1000 MW at 58.9 Hz + 0.2 seconds
1500 MW at 58.6 Hz + 0.2 seconds

4) Calculate and plot the decay curve as shown in Figure 7 to at least 0.2 second after the frequency reaches 59.1 Hz. This is the point at which the first load is shed and which results in a reduction in the rate of frequency decay. The equation used to obtain this curve is:

$$\Delta f = \frac{\Delta P}{D'} \left(1 - e^{\frac{-D't}{M}}\right)$$

where
M = 2H = 2(7.2) = 14.4
D' = 1.75
ΔP = -0.5

t (sec.)	f (Hz)
0.1	59.79
0.2	59.59
0.3	59.34
0.4	59.19
0.5	58.99
0.6	58.79
0.7	58.60
0.8	58.41

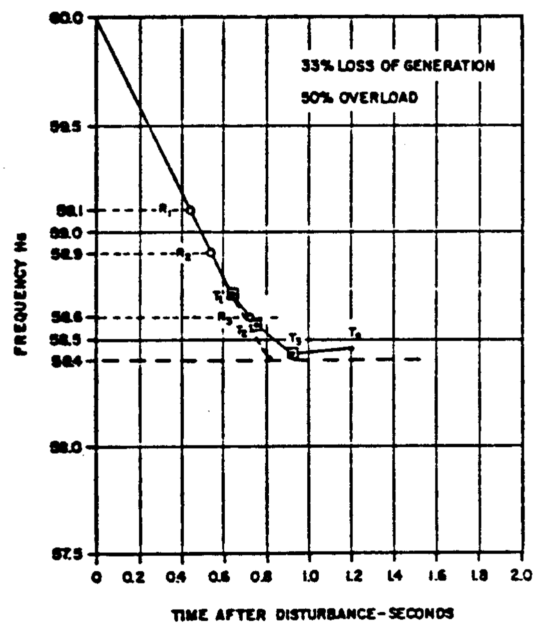


Fig. 7 Frequency decline due to system overload - determined analytically

5) Calculate the time at which the first relay operates or read from the above plot. It can be calculated from the equation:

$$t = \frac{-M}{D'} \ln \left(1 - \frac{D'\Delta f}{\Delta P}\right)$$

where Δf = -0.9 Hz = -0.015 per unit
ΔP = -0.5
D' = 1.75
M = 14.4

t_1 = 0.44 seconds and shown as R_1 in Figure 7.

The relay and breaker time added to this gives the time the first load is shed:

$T_1 = 0.44 + 0.1 + 0.1 = 0.64$ seconds

Note on the plot that the second step relay (58.9 Hz) has operated before the first block of load is shed.

Calculate this time as above:

$$t_2 = \frac{-M}{D'} \ln \left(1 - \frac{D' \Delta f}{\Delta P}\right)$$

$= 0.54$ sec

and shown as R_2 on Figure 7.
$T_2 = 0.54 + 0.1 + 0.1 = 0.74$ seconds

6) The frequency will decay to some frequency below 59.1 Hz before the first step of load is shed; this can be read from the plot or calculated from from the formula for Δf for the specific time 0.64 seconds and is equal to 58.71 Hz.

This point is plotted at T_1 in Figure 7.

After the load has been shed at point T_1 the decay in frequency will follow a new curve.

7) This new curve will be followed until the second load shedding point T_2 is reached. This is the interval from $T_1 = 0.64$ seconds to $T_2 = 0.74$ seconds. During this interval:

Load = 10000 - 1000 = 9000 MW
Generation = 6666 MW

$$\Delta P = \frac{6666-9000}{6666} = -0.35 \text{ per unit}$$

$$D' = 1.5\,(1 + .35) - 0.35 = 1.67$$

The frequency at $T_2 = 0.74$ seconds can now be calculated.

$$\Delta f = \frac{\Delta P}{D'} \left(1 - e^{\frac{-D't}{M}}\right)$$

where t is the interval, $0.74 - 0.64 = 0.10$ seconds, and Δf is the change of frequency, in per unit, between the starting frequency, 58.71 Hz, and the frequency 0.10 seconds later.

This calculation results in a frequency of 58.67 Hz for T_2 and is plotted in Figure 7.

Note that in this interval the relay for the third step operates at 58.6 Hz. The time at which it operates can be calculated from

$$t = \frac{-M}{D'} \ln \left(1 - \frac{D' \Delta f}{\Delta P}\right)$$

where

$$\Delta f = \frac{58.71 - 58.6}{58.71}$$

$= -0.00187$ per unit

$\Delta P = -.35$ per unit
$D' = 1.67$
$M = 14.4$

$t_3 = 0.07$ seconds after T_1

and shown as R3 in Figure 7

$T_3 = 0.64 + 0.07 + 0.2 = 0.91$ seconds

8) After additional load has been shed at point T_2 the frequency decay will follow a new curve between T_2 and T_3. This interval is $T_3 - T_2$ seconds, $0.91 - 0.74 = 0.17$ seconds.

During this interval

Load = 9000 - 1000 = 8000 MW
Generation = 6666 MW

$$\Delta P = \frac{6666 - 8000}{6666}$$

$= -0.2$ per unit

$$D' = 1.5\,(1 + 0.2) - 0.2 = 1.6$$

The initial frequency is 58.57 Hz and the frequency at T_3 can be calculated from

$$\Delta f = \frac{\Delta P}{D'} \left(1 - e^{\frac{-D't}{M}}\right)$$

$\Delta f = -0.00239$ per unit or -0.14 Hz

The frequency at T_3 is $58.57 - 0.14 = 58.43$ Hz.

9) After the last load shedding point of this schedule, T_3, the generation exceeds the load and the frequency will begin to recover.

Load = 8000 - 1500 = 6500 MW
Generation = 6666 MW

$$\Delta P = \frac{6666-6500}{6666} = +\,0.0249 \text{ per unit}$$

$D' = 1.5\,(1 - 0.0249) + 0.0249 = 1.49$
The initial frequency is 58.43 Hz.

ANALYTICAL SOLUTION (Continued)

Since a fourth step has not been considered, arbitrarily select an interval of time after T_3, calculate the frequency change, and plot the final point T_e.

Assume T_e = 1.2 seconds.
The interval, therefore, is 1.2 - 0.91 = 0.29 seconds.

Δf = 0.0005 per unit or 0.03 Hz.

The frequency at T_e is 58.43 + 0.03 = 58.46 Hz.

SUMMARY

A load shedding schedule has been selected and a verification made that this schedule will meet the requirements of a particular system overload condition. It was assumed that only digital relays were to be used and therefore the calculation was simplified.

The system condition considered was:

Load = 10000 MW
Loss of 3333 MW of generation resulting in 0.5 per unit overload, initially, on the remaining 6666 MW of generation.

It was found that a load shedding schedule of three steps: 59.1, 58.9, and 58.6 Hz shedding 1000, 1000, and 1500 MW of load, respectively, will arrest the decay in frequency before 58.4 Hz is reached.

Results calculated by both graphical and analytical methods are:

Analytical Calculation
Shows operation at

Step	Frequency (Hz)	Time (Seconds)
59.1	58.71	0.64
58.9	58.57	0.74
58.6	58.43	0.91

Graphical Calculation
Shows operation at

Step	Frequency (Hz)	Time (Seconds)
59.1	58.69	0.65
58.9	58.56	0.74
58.6	58.44	0.92