# Ancillary Services Measurement Handbook

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EPRI Project Manager
N. Abi-Samra

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

**EPRIsolutions, Inc.**
**Encotech, Inc.**
**LCG Consulting**

## ORDERING INFORMATION

Requests for copies of this report should be directed to EPRI Customer Fulfillment, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2.

# CITATIONS

This report was prepared by

EPRIsolutions
3412 Hillview Avenue
Palo Alto, CA 94304

Principal Investigator
N. AbiSamra
J. Platt

Encotech, Inc.
207 State Street
Schenectady, NY 12301

Principal Investigator
J. Kure-Jensen

LCG Consulting
4962 El Camino Real, Suite 112
Los Altos, CA 94022

Principal Investigators
R. Albert
C. Lund
N. Brown
M. Macatangay

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# REPORT SUMMARY


In the deregulated electric utility industry, it is anticipated that many ancillary services (A/S) will be sold by “generators” to operating authorities (OAs) or independent system operators (ISOs). Such trade in A/S will require contractual agreements, and these agreements will need to specify quality and quantity of service to be supplied. This, again, means it will be necessary to certify or measure the quality of an A/S to be supplied, as well as the quantity actually supplied. Towards that end, this report describes methodologies for measurements of six ancillary services.

## Background

EPRI initiated a Measurement of Ancillary Services in 1999. By the time the project got underway, the North American Electric Reliability Council (NERC) had organized a task force on “Interconnected Operations Services” (IOS), which is the name used for the equivalent of FERC’s A/S. NERC’s early drafts of Policy 10 on IOSs (Ref. 2 and 3 are the latest revisions) included recommended ways of measuring IOSs for certification and for performance. Consequently, the EPRI measurements proceeded to demonstrate the recommended procedures.

The A/S considered here have been supplied for many years by utilities. But the supply was probably established in a less formal way than now planned. For example, the load-following capability of a unit was established by a utility or control area from experience and programmed into the utility’s or area generation control’s dispatching algorithm. In the future, the OA or ISO will not own any of the generating units or direct them to supply the required A/S. Rather, they must contract and purchase the necessary A/S of the correct performance and, in the required amount, make sure that reliability and performance will stay within applicable criteria.

## Objectives

To summarize lessons learned from the previous EPRI tests on six A/S from generators and demonstrate certification and performance measurements in the field for each of the six services; to provide structured methodologies and practical procedures for performing the six tests; to provide detailed checklists and procedures for performing the tests using, to greatest possible extent, existing station instrumentation; to update the previous EPRI tests for A/S to the latest NERC requirements since NERC has updated its requirements after the tests have been completed; to contrast the testing and qualification requirements at different ISOs; and, to estimate the contribution to power plant earnings from energy and A/S for specific plants and regions.

## Approach

The project team reviewed all six previous tests performed in 1999 and 2000 and compared them against the new NERC requirements. The team highlighted lessons learned from the previous tests and provided structured methodologies and detailed checklists to conduct the six tests and

analyze their results. Team members also contrasted requirements at different ISOs to the testing performed. To illustrate the value of participating in A/S markets, investigators simulated the income that would be received by specific representative baseload, mid-merit, and peaking units in New York, New England, Texas, and California. The simulation was based on year 2000 actual hourly energy and A/S prices in those regions.

**Results**

This handbook provides guidance for future testing of A/S. The following items were covered: validation of the previous EPRI tests against the new version of the NERC IOS document; summary of lessons learned from all six tests; recommendation for increased effectiveness of future testing; examples of checklists for tests that will facilitate future testing of services (these included test procedures and data lists); data evaluation templates with sample test data; requirements of A/S testing and qualifications ISOs from across the nation: California, Texas, and New York; and, the issue of voltage control from generators and its provision from transmission systems equipment, such as Flexible AC Transmission System (FACTS). A/S may make an important contribution to income for all plant types in all regions. Baseload units capable of regulation or spin may earn up to 40% of their income from A/S, and mid-merit units may earn up to three-fourths of their income from A/S. Peaker units capable of ten-minute non-spinning reserve may earn up to 48% of their income from A/S.

**EPRI Perspective**

This report describes methodologies and procedures for measurements of six A/S (regulation, load following, black start, operating reserve—spinning and supplemental, and reactive power supply from generation resources due to their importance and potential profitability in competitive markets). It is anticipated that these, and other services, will be sold by “generators” to OAs or ISOs. Such trade in A/S will require contractual agreements, and these agreements will need to specify quality and quantity of service to be supplied.

**Keywords**

Ancillary services
Black start
CAISO, ERCOT, NTISO, NEISO
Load follow
Measurements methods
NERC policy 10
Power markets trading
Regulation
Voltage support

# ABSTRACT

This handbook updates the testing that has been performed by EPRI on the six generator-based ancillary services in 1999 and 2000 to the latest NERC requirements. Lessons learned from those tests and methods to increase effectiveness of future testing are presented. The handbook presents checklists for tests and details responsibilities of testing teams and generator owners. It reviews testing and qualification requirements at a number of independent system operators (ISOs) and contrasts them to the North American Electric Reliability Council (NERC) requirements and EPRI testing. Further, it presents the concept of supplying ancillary services from transmission system equipment, such as the Flexible AC Transmission System (FACTS). It also illustrates the financial importance of participating in ancillary services markets by contributions to income from selling energy and ancillary services for specific power plant configurations in four U.S. regions with competitive ancillary services markets.

# ACKNOWLEDGEMENTS

While the overall methods and principles applied to the measurements described in this report will easily be recognized by utility engineers, it required input and guidance from many sources to arrive at meaningful results. Their contributions are gratefully acknowledged, in alphabetical order:

- Gerry Cauley, NERC staff liaison to the IOSITF.
- Dave Evanoski of the New York Independent System Operator (NYISO).
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- Robert S. Henry of Duke Energy and current chair of the North American Electric Reliability Council's (NERC) Interconnected Operations Services Implementation Task Force (IOSITF).
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- Gail Pedersen for the assembling and formatting this document (EPRIsolutions, Inc.).
- Paul Spicer of Wisconsin Public Service Corporation, member of the IOSITF.

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# 1 INTRODUCTION

EPRI initiated a Measurement of Ancillary Services project in 1998 and focused initially focused on topic sketching out how these services, defined by FERC in its Order 888 in 1996 (Ref. 1), could be measured. By the time the project got underway, NERC had organized a task force on "Interconnected Operations Services" (IOS), which is the name used for the equivalent of FERC's Ancillary Services. NERC's early drafts of Policy 10 on IOSs (Ref. 2 and 3 are latest revisions) included recommended ways of measuring IOSs for Certification and for Performance. Consequently, when the measurement proceeded to demonstrate the recommended procedures.

The measurements are covered in several EPRI reports (Ref. 5-7). NERC's IOS task force introduced several changes in its draft Policy 10 on IOSs during the two years of the testing projects. Some of these changes came after the performance of a test and could not be accounted for. The tests that EPRI conducted revealed insights which need to be captured, and lessons learned. In addition this document contrasts the requirements for Ancillary Services testing at different ISO's and compares their requirements to the NERC policy 10 requirements as well as the tests that EPRI has performed over the last two years. For these reasons, this document has been prepared to produce update the project with a summary report, which is presented here.

It consists of the following sections:

Updating to Current Version of NERC IOS Document

Summary of the Six Tests and Lessons Learned

Effectiveness of Future Testing

Examples of Check Lists, Test Procedures and Data Lists

Data Evaluation Templates with Sample Test Data

Current Industry Measurements on Ancillary Services

Voltage Control

The Contribution of Energy & Ancillary Services to Net Income of Generating Units in U.S. Power System

Summary and Conclusions

Glossary of Terms

The Appendices to this handbook contain the following:

Appendix A: Voltage Control with Generators

Appendix B: Voltage Control with Transmission Equipment

Appendix C: NERC Reference Document Interconnected Operations Services, March 28-29, 2001

Appendix D: Excerpts from CAISO Management of Ancillary Services Certification Testing

Appendix E: Excerpts from ERCOT Protocols Ancillary Services

Appendix F: Abstracts of EPRI Publications on Ancillary Services

Appendix G: Abstracts of IEEE and CIGRE Recent Publications on Ancillary Services

# 2

# UPDATING TO CURRENT VERSION OF NERC IOS DOCUMENT

NERC's draft Policy 10 on IOS (Ref. 2 and 3) was in various stages during the 1999 - 2000 testing. The Policy contained requirements both for the supplier of IOSs[1] (generating units) and for the Operating Authority. Testing of six IOSs was conducted per draft Policy 10 only as specified for the supplier of IOS, not as specified for the Operating Authority. Consequently all the following observations apply only to requirements against the IOS supplier.

NERC's Policy 10 draft was not adopted as a policy as expected, but issued as a "Reference Document" March 28-29, 2001, (Ref. 4), contained in the Appendix. Some revisions were introduced by NERC's IOS Taskforce to draft Policy 10 during the two years of testing. Other changes were made by the taskforce in rewriting it to a Reference Document. Most changes are minor. The more significant ones are reviewed below.

## Sample Standards

### *Regulation and Load Following*

In the Sample Standard[2] for this IOS it is now recommended to establish numerical values for max. and min. load and for maneuverability in the form of ramp rates. For the testing done in 1999, we had anticipated this need.

Quoting from Ref. 4 page 15:

> ***Declaration of LOAD FOLLOWING Response Capability. An IOS SUPPLIER providing LOAD FOLLOWING shall declare to the OPERATIING AUTHORITY the IOS RESOURCE's:***
>
> 6.1. *Maximum and minimum outputs that define the LOAD FOLLOWING range of the IOS RESOURCE.*
>
> 6.2. *The ramp rate and acceleration of the IOS RESOURCE.*
>
> 6.3. *The minimum time period between requests for load changes*

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1 IOS -"Interconnected Operations Services"- is NERC's terminology for services similar to FERC's Ancillary Services. The two terms are used interchangeably in this report.

2 "Reference Document" refers to NERC' Reference Document, Interconnected Operations Services (Formally Known as NERC Policy 10) Dated March 28, 2001

For the testing done in 1999, we had anticipated the above need. Such limits were declared for the unit, and the testing observed these limits.

### Contingency Reserves – Spinning and Supplemental

- In the Sample Standard for this IOS, there are now similar requirements for capacity and ramp rates. Our testing included such limits. Also, a new term, TDCS , is introduced. It is the time allowed by the Disturbance Control Standard (DCS) for activation of reserves. It will vary from region to region.

The details of these will appear from the following quotation from Ref. 4 page 17.

> *Provision of CONTINGENCY RESERVES.* ***In response to the instructions of the OPERATING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall:***
>
> *9.1. Provide between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING within ($T_{DCS}$ – X) minutes of a call by the OPERATING AUTHORITY requesting CONTINGENCY RESERVE. X is the number of minutes agreed to in advance by the OPERATING AUTHORITY and IOS SUPPLIER that allows for the OPERATING AUTHORITY to respond to a contingency and call for deployment of CONTINGENCY RESERVE.*
>
> *9.2. Maintain between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING for at least 15 minutes subsequent to ($T_{DCS}$ – X).*
>
> *9.3. Return to the non-contingency scheduled output (or consumption) +/- 10% of the requested amount of CONTINGENCY RESERVE, within ten minutes of instructions from the OPERATING AUTHORITY to do so. Alternatives to the +/- 10% bandwidth and the ten-minute period may be established by the Operating Authority through an open process defined in Requirement 2-Section 3.1-Operating Authority Requirements.*

Testing in 2000 was performed against a value for TDCS of 10 min.
Finally, the duration of full reserve capacity has been changed, from 20 to 15 min.
These changes do not appear to invalidate the method or experience gained from the testing.

### Reactive Power Supply from Generation Sources

In the Sample Standard for this IOS, it is now stated that tolerances and times for deployment of this IOS must be established and recommended values are listed.

When the testing was done, there were no values available.

### Frequency Response

A Sample Standard for this new IOS has been included. At the time of testing, Frequency Response was not defined as an IOS; and no testing was done for Frequency Response. The recommended testing is, however, very similar to the testing recommended in other standards, e.g. IEEE 122 (Ref. 8), and AMNSI/ASME PTC 20.1 (Ref. 9). Such testing is, for example, carried out by turbine manufacturers. Hence testing should not present significant new challenges.

The Sample Standard for this IOS contains several changes. One is that a generating unit that can withstand loss of all connections to the grid and continue to operate in a stable mode, can also qualify as a black start unit. Another is that the testing of black start capability is separated into two sections:

9. Starting of the unit up to a stable point, and

10. line energizing and application of load from a unit to be started with the help of the black start unit. This change has no impact on the experience from the testing reported on in 1999, which went through both sections.

### *Black Start*

The Sample Standard for this IOS contains several changes. A significant one is that a generating unit that can withstand loss of all connections to the grid and continue to operate in a stable mode, can also qualify as a black start unit. Another is that the testing of black start capability is separated into two sections:

9. Starting of the unit up to a stable point, and

10. line energizing and application of load from a unit to be started with the help of the black start unit.

These changes are described in Ref. 4 page 21 as follows:

> *IOS RESOURCE Capabilities. An IOS SUPPLIER of SYSTEM BLACK START CAPABILITY shall provide the following:*
>
> *7.1. Capability to start a self-starting unit within a time specified, from an initial dead station and auxiliary bus condition. Alternately, a SYSTEM BLACK START RESOURCE may be a generating unit that is able to a) safely withstand the sudden and unplanned loss of synchronization with the BULK ELECTRIC SYSTEM and b) maintain generating capacity for a specified period of time.*
>
> *7.2. Capability of re-energizing, within a time specified, the plant auxiliaries necessary to start one or more additional units, if the SYSTEM BLACK START CAPABILITY unit is planned as a cranking source for one or more of these additional units.*
>
> *7.3. Capability of picking up external load within a specified time.*

This change has no impact on the experience from the testing reported on in 1999, which went through all sections.

## Measurement and Certification Methods

The Reference Document on IOSs (Ref. 4) contains samples of possible metrics for all services. For some services, these are more specific than was the case when our testing was done. Following is a review of some of these.

## Performance Measurements

### Regulation and Load Following

- A very detailed specification for the scheduled load, Ps is provided in the form of a flow chart. This accounts for allowable ramp rates, R, and jerk rates, J.
- A flow chart for the calculation of Supplier Control Error, SCE, is also provided, and the use of 10 min. averages, |SCE|10 is recommended.

These two specifications were anticipated in our testing in 1999, and the data were evaluated as recommended. The recommended limits for acceptance are more specific now. But the experience from the testing remains completely valid. Only the performance of a unit might now be classified differently according to revised criteria.

### Operating Reserve – Spinning and Supplemental

- Instead of a fixed time of (10 - X) minutes for ramping up to the declared reserve capacity, a time (TDCS – X) minutes has been introduced, where TDCS is the same as described above.
- The tolerance for the delivered reserve has been revised from 100 – 110% to 100 – 120%. These changes do not have impact on the test method and experience gained.

### Reactive Power Supply from Generation Sources

New requirements are:

- For the case when the IOS supplier is providing voltage control, a new measure, Voltage Supply Error, VSE, has been introduced together with limits therefore. VSE = (Va – Vs), (actual Voltage – scheduled Voltage) is to be determined for each 10 min. period, and 98% of values of VSE must be within +/- 2% of scheduled voltage.

For the case when the IOS supplier is providing VAR control, a deviation (VARa – VARs) shall be determined for each 10 min. period, and must in 95% of cases be within +/- 10% of scheduled value.

- The automatic voltage regulator, AVR, must be in service at least 98% of the time.

These metrics do not affect the validity of measurement methods demonstrated in year 2000, nor the experience gained.

### Frequency Response

Performance testing of this response was only defined after the completion of the demonstration tests. Please refer to the comments under Sample Standards above.

### Black Start Capability

- The IOS task force has acknowledged the great complexity added to the testing of this service in its draft policy 10 (ref. 2&3) by requiring that it must include the element of surprise.
- The Reference Document now refers measurements of the performance to observations during a real restoration emergency or to a staged demonstration at an arranged time.

This change has no impact on the experience from the testing reported on in 1999.

## Certification Measurements

### Regulation and Load Following

In the current version of the Reference Document no certification testing is required for these services. This is justified by the fact that these IOSs are measured continuously, so that poor performance of a unit will be obvious.

### Contingency Reserves

The requirements are the same as for the testing performed in year 2000 with the exception of the introduction of the time limit TDCS described above, and a revised requirement that the measured reserve must be within 100% to Y% of the declared amount, where Y is an interconnection-specific factor. These changes do not affect the methodology demonstrated and the experience gained. They may alter the degree of qualification demonstrated.

### Reactive Power Supply from Generation Sources

The performance of the AVR must be tested per NERC Planning Standards, as must the reactive capacity of a unit. There are no new requirements for these measurements relative to the time of testing in year 2000. But new metrics are suggested, as specified in the NERC Planning Standards “System Modeling Data Requirements, Generation Equipment.” Sections 2B, Measurement 4, and 2B, Measurement 6.

### Frequency Response

Certification testing of this response was only defined after the completion of the demonstration tests. Please refer to the comments under Sample Standards above.

### Black Start Capability

In the Reference Document, the certification requirements are separated more sharply than they were in draft Policy 10. They now consist of:

- Basic Starting Test
- Line Energizing Test which includes a Basic Starting Test
- Load Carrying Test that includes both a Basic Starting and Line Energizing Test
  the requirements for each of these tests have not been revised significantly. There are revised recommendations for the frequency of these tests.

The revisions do not affect the methodology and the conclusions from the test reviewed in 1999.

# 3
# SUMMARY OF THE SIX TESTS AND LESSONS LEARNED

During 1999 and 2000 the EPRIsolutions team, conducted demonstration tests according to the then existing versions of NERC draft Policy 10 on Interconnected Operations Services, IOSs (Ref. 2 and 3 show latest revisions). The six IOSs tested were:

In 1999:

1. Regulation, reported in Ref. 5
2. Load Following, reported in Ref. 5
3. Black Start, reported in Ref. 6

In 2000:

1. Operating Reserve – Spinning, reported in Ref. 7
2. Operating Reserve – Supplemental, reported in Ref.7
3. Reactive Power from Generation Resources, reported in Ref. 7

Following is a summary of each of these tests listing such factors as; objectives, practicality, effort and cost, benefits and "lessons learned".

## Regulation and Load Following

As suggested in draft Policy 10, these two IOSs were evaluated together. For details of these tests, please see Ref. 5. A one-line diagram of the test configuration may be found at the end of this section.

### *Objectives*

- To interpret the certification requirements and performance testing in draft Policy 10 into practical procedures that can be performed routinely on a generating unit, using to greatest possible extent existing station instrumentation.
- To demonstrate the testing method and procedures in the field for each IOS.

- To evaluate the data and report on the testing in a format that can be used by “generators” as guide to performing the testing at their own installations.

### Test Site

- Testing was conducted on a 180 MW coal fired unit operating at 1850 psig, 1000/1000°F, equipped with modern coordinated boiler-turbine control.
- It was possible to conduct the testing when the unit was in its normal operating mode and testing was done within the normal, maximum limits for its participation in Regulation and Load Following.

### Preparations

- A detailed, step-by-step test plan and a detailed checklist had been prepared and reviewed by all concerned. (Details of preparations, including Test Plan and Check List are included in Ref. 5; the latter two are also reproduced in the Appendix).
- The preparations included determining the range and ramp rates of regulation and load following to be evaluated, and the operating mode and dispatch signals required.
- Also included was evaluating the plant data acquisition system and ascertaining that all the test data needed were being acquired and stored at the required intervals.

### Instrumentation

- The station instrumentation was reviewed, including calibration records, and was found adequate.
- No special instrumentation was used.
- All required data were stored in the plant data acquisition system (PI) at the required time intervals (4-6 s) and extracted later for evaluation.

### Testing

- Because testing involved fairly rapid and large load swings, testing was done at a time of the daily cycle (night), selected by the AGC, during which the load swings could readily be accommodated by other units operating under its control.
- The AGC also initiated the testing and transmitted simulated dispatch signals to implement the declared load ranges and ramp rates.

### Effect on Unit and Grid

- Significant parameters affecting the unit, such and steam pressure and temperatures, drum level, were watched carefully.
- All stayed within allowed limits. All unit protective systems were in service during the testing.

- There were no alarms or upsets. The testing caused two small violations of CPS 2 leading to 94.4% compliance during the test period.

### Results

- The data were evaluated in the form of SCE (supplier control error) per NERC draft Policy 10 in effect at the time.
- Data were acquired at 6 s intervals from which 1 min averages were calculated.
- All the recommended, normal statistic measures were calculated.
- The unit performed very well as evaluated by all the metrics recommended by NERC.

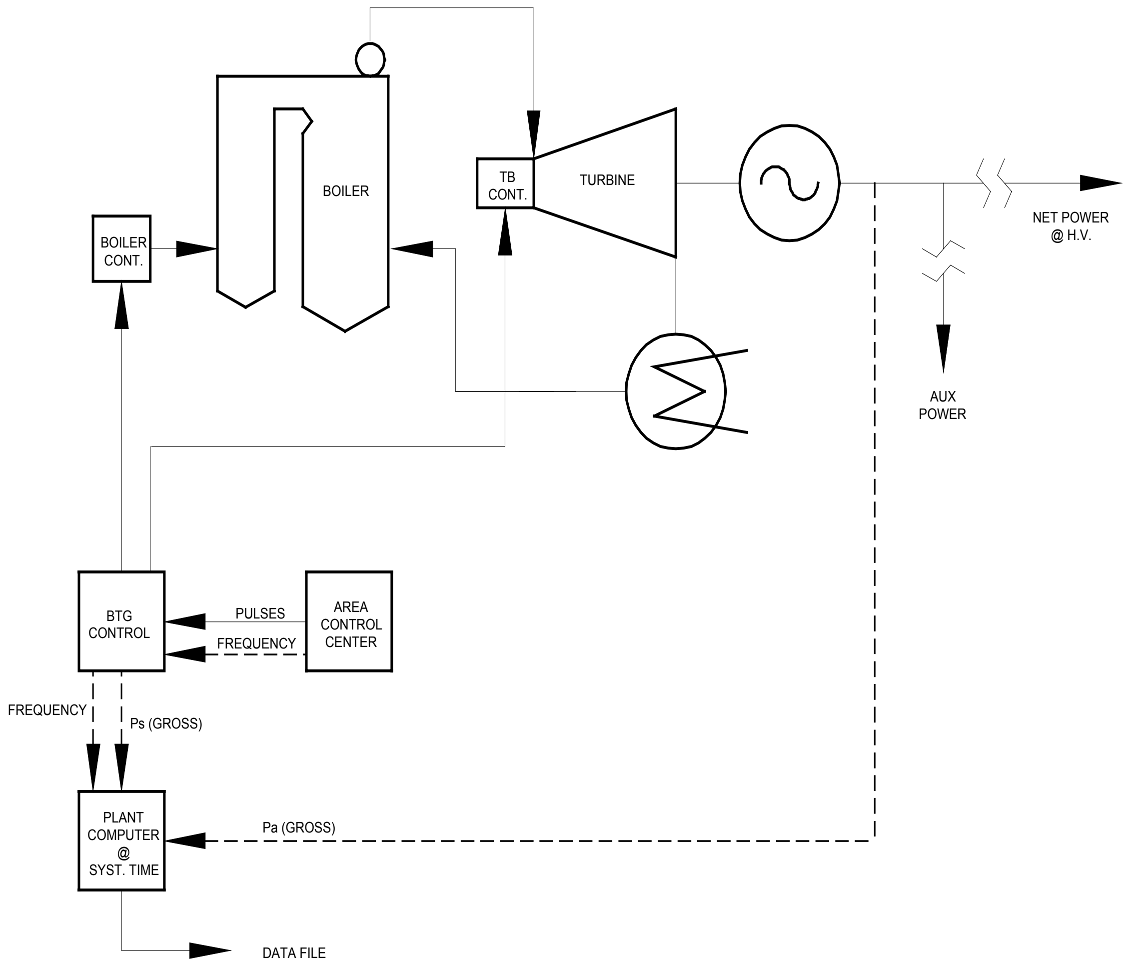
### Effort

- A performance engineer whose total involvement was approx. 40 hours led the utility's participation.
- EPRIsolutions' applied time was about 120 hours including report writing.
- This can be expected to be reduced significantly for future testing due to the experience gained and reusable documents and evaluation templates.

### Benefits

- Testing on-line was easy to implement, requiring only station instrumentation and caused no upsets to the unit or the grid.
- The metrics recommended by NERC could readily be calculated and performed a fine evaluation of the unit's performance.
- The station personnel and the utility gained good confidence in the units' maneuverability which had been surmised earlier, but never demonstrated rigorously.
- When dispatched within the declared MW range, ramp and acceleration rates the unit performed flawlessly.

The utility felt confident that it would be able to comply with any future dispatch limits and that the unit would meet requirements of an independent Operating Authority for supplying Regulation and Load Following.




The figure above illustrates the test configuration for 1. Regulation and 2. Load Following, in a one-line diagram. In principle, the same configuration was used for tests 4. Operating Reserve – Spinning and 5. Operating Reserve – Supplemental.

## Black Start

The requirements of draft Policy 10 turned out to be so demanding and require so much advance preparation that it was not possible to schedule a test within the allocated time or find a utility that was willing to undergo the expense, time, and effort. Instead we found a utility that had recently conducted a black start test (including energizing of lines to two other stations and startup of units in these stations), and applied NERC's criteria to the test results. For details, please refer to Ref. 5 and 6.

### Objectives

To interpret the certification requirements and performance testing in draft Policy 10 into practical procedures that can be performed routinely on a generating unit, using to greatest possible extent existing station instrumentation.

- To demonstrate the testing method and procedures in the field for each IOS.
- To evaluate the data and report on the testing in a format that can be used by "generators" as guide to performing the testing at their own installations.
- Because the testing had already been planned and conducted by the utility, there was no opportunity to apply specific details of draft Policy 10. But it turned out that the testing had been conducted almost exactly as if the NERC requirements had been known.
- Due to the complexity of the requirements it turned out not to be possible to include the element of surprise prescribed in draft Policy 10.

### Test Site

Testing included three power stations, a substation and interconnecting lines. The power stations were:

- Station A: 2 hydro units, the black start units — 13 MW each
- Station B: 1 steam unit, started with power from A — 284 MW
- Station C: 1 steam unit, started with power from A — 140 MW

### Preparations

- The utility had prepared a detailed test plan extracted from its restoration plan.
- The plan was reviewed with participating personnel, and a few drills were conducted. Because three stations and interconnecting lines had to be shut down, no element of surprise could be included.
- The test had to be conducted at a time that permitted the elaborate preparations.

### Instrumentation

- The entire procedure was in principle performed with the help of existing instrumentation and communication equipment. This must obviously be so, because the objective of the testing is to demonstrate that this equipment is adequate.
- A few strip chart recorders had been added to record frequency, voltage, MW and MVAr at strategic points.

### Testing

- Test procedures were in principle conducted by the operating personnel that would have to perform these procedures in case of a real restoration situation.

- Data and observations were taken by test personnel.
- The test commenced at 7:00 AM, all four units were off and lines disconnected at 7:45 AM.
- The restoration began at 8:00 AM and was completed at about 5:45 PM.

### *Effect on Units and Grid*

- These effects were obviously very significant.
- The testing was conducted at a favorable time of year when taking units and lines out of service did not create a shortfall.

### *Results*

- The overall result was satisfactory to the utility.
- And the review of the testing against draft Policy 10 requirements concluded that the black start unit could have been certified as capable.
- The testing revealed a number of problems in the equipment, such as insufficient power sources for communication equipment, faulty frequency measurements making synchronization difficult.
- Also the need for periodic training of personnel in procedures that are performed infrequently stood out.

### *Effort*

- The utility's expenditure of time, resources and manpower was significant.
- A major effort is to create and update the restoration plan.
- No information was obtained about the magnitude of the utility's efforts, but it is estimated to be many manweeks of effort.

### *Benefits*

- Testing demonstrated that Station A was capable of performing black start and support the cranking of two steam units that are part of the utility's restoration plan.
- Several areas needing attention were found as mentioned above under Results.

## Operating Reserve – Spinning and Operating Reserve – Supplemental

Draft Policy 10 states: "Testing for Contingency Reserve Spinning and Supplemental may be conducted individually or as one test". The latter was done for the testing reviewed here. For details please see Ref. 7.

### Objectives

- To interpret the certification requirements and performance testing in draft Policy 10 into practical procedures that can be performed routinely on a generating unit, using to greatest possible extent existing station instrumentation.
- To demonstrate the testing method and procedures in the field for each IOS.
- To evaluate the data and report on the testing in a format that can be used by "generators" as guide to performing the testing at their own installations.

### Test Site

- Testing was performed on a 500 MW, coal fired reheat steam unit, operating at sub-critical pressure (2000 psig, 1000/1000 F), powered by a drum boiler.
- The unit was equipped with a modern coordinated boiler turbine control system implemented in digital electronics.

### Preparations

- A detailed, step-by-step procedure had been prepared and reviewed with the utility's plant performance engineer well in advance.
- This included a specific list of data to be recorded and the preferred time interval between readings. This procedure and checklist are included in Ref. 7.
- Of particular concern was the determination of the reserve capability to be demonstrated. Because this was a large coal fired unit, supplemental reserve could only be delivered from a synchronized condition within the time limit for this type of reserve. This made the spinning and supplemental reserve capability identical.
- It was determined to demonstrate the capability only from a single power level, selected to be about 60% of rated. The reserve was set at a rate of 6 MW (=1.2% of rated capacity) per minute for 10 minutes for a total of 60 MW, which is a fairly ambitious performance for a large reheat steam unit.

### Instrumentation

- Existing station instrumentation and a new data acquisition system were completely adequate for the testing.
- The existing station instrumentation recorded about 2000 parameters at down to 10 s intervals. No modifications or special instrumentation were required. The only special effort was to write a template for data extraction from the standard station log.

### Testing

- Because testing involved fairly rapid and large load swings, it was done at a time of the daily cycle (night), selected by the AGC, during which the load swings could readily be accommodated by other units operating under the AGC.

- In this power station, reserve capacity would normally be requested by phone call from the AGC in response to which the operator would initiate the reserve on the BTG board.
- This method was followed for the test by the operator selecting the ramp rate and target load as input to the coordinated boiler turbine control system.
- The performance of the unit in delivering the reserve capacity and maintaining voltage and other parameters was monitored on CRT screens.

### Effect on Unit and Grid

- Significant parameters affecting the unit, such as steam pressure and temperatures, and drum level were watched carefully. All stayed within allowed limits.
- All unit protective systems were in service during the test. There were no alarms or upsets. The grid absorbed the load swings without any disturbances.

### Results

- The first test run was initiated at a time when the unit was not stable. The delivery of reserve was disappointing.
- The achieved ramp rate was about half the declared one and after reaching the declared load, it could not be sustained in a stable manner for the time required.
- After some adjustment (tuning) of the coordinated boiler turbine control system, a new run was made in which the unit almost achieved the declared ramp rate up and down.

### Effort

A performance engineer whose total involvement was about 40 hours led the utility's participation. Normal shift operators performed the testing in the plant without disturbance to their duties. The consultant's applied time was about 120 hours including report writing. The latter is expected to be cut reduced significantly for future testing thanks to the experience gained and reusable documents and evaluation templates.

### Benefits

- The utility learned how to conduct a rigorous test of a unit's reserve capability. In this case the following specific lessons were learned.
- The unit could not achieve the expected loading rate when it was not in a stable condition at the time of reserve initiation.
- Even after tuning of the coordinated boiler turbine control system, the expected ramp rates were barely reached and the reserve load could not be maintained within the tolerance specified by NERC.

## Reactive Power from Generation Resources

- The testing of the automatic voltage regulator (AVR) requires both off-line and on-line testing, the latter with significant step changes.
- The testing required to determine the gross and net reactive capability of a generator also requires large perturbations in the reactive output of the generator.
- Within the time available, it was not possible to find a utility that was willing to perform these demanding tests.
- Our conclusion, based on the utilities we contacted, is that these two tests are very demanding because they require taking a unit out of service as well as a lot of preparations and instrumentation.
- Owners are unlikely to perform these tests other than when mandated. Consequently, the only reactive power testing performed was the response to change in scheduled reactive power. Objectives and procedure are described in Ref. 7.

### *Test Site*

Testing was performed on a 588 MVA, two pole, hydrogen cooled generator equipped with AVR and MVAR control capability.

### *Preparations*

A detailed, step-by-step procedure had been prepared and reviewed with the utility's plant performance engineer well in advance. This included a specific list of data to be recorded and the preferred time interval between readings. This procedure and checklist are included in Ref. 7. Since the unit normally operates under VAR control, the client only wished to test this performance. Initially, the procedure called for a step change of 30 MVA from about 110 to 80 MVAR. A later run used a different step change.

### *Instrumentation*

Existing station instrumentation and a new data acquisition system were completely adequate for the testing. It recorded about 2000 parameters at down to 10 s intervals. No modifications or special instrumentation were required. The only special effort was to write a template for data extraction from the standard station log.

### *Testing*

As for the other testing involving significant changes in operating parameters, this testing was done at night when the grid was not highly loaded and other units could compensate for the sudden changes imposed. The first test consisted of the operator rapidly changing the MVAR setting by about 30 MVA from 110 to 80 MVAR on the BTG board followed by a period of no change in the set point. As observed in real time on a CRT, the unit responded rapidly, as expected, completing the VAR change in about 30 s. But when analyzed by the recorded data, the unit did not seem to have responded correctly. A repeat test was run a few weeks later consisting of a step change from 30 MVAR to 90 MVAR and back to 40 MVAR 15 minutes later.

The steady state performance of the VAR regulator was also recorded for about 10 min.

### *Effect on Unit and Grid*

No adverse effects were noted on the generator operating parameters. No upsets were reported by the AGC.

### *Results*

When the first test run was analyzed by means of the data recorded every 10 s, the unit appeared to have taken almost 3 min (170 s) to complete the 30 MVAR change, different from observation during the test. Detailed investigation revealed that the MVAR data recording was set to be "by exception" with a 12 MVA dead band. This meant that variations inside the dead band would not be recorded; only the previous value would be repeated. This made the change of 30 MVAR appear as two partial step changes occurring each time the value had change more than the dead band of 12 MVAR.

During the later run with a change from 30 to 90 MVAR, the dead band had been set very low, and the unit responded as expected, completing the MVAR change within 30 s.

This response met the requirements of NERC draft policy 10 and the recommended metrics in the Reference Document.

The variation in reactive power at a steady MVAR set point was also recorded. Analysis shows it to be within +/- 2 MVAR of the set point of 90 MVAR. This meets the metrics of the Reference Document discussed earlier in this report under Performance Measurements of +/- 10% of scheduled value at least 95 % of time.

### *Effort*

The utility's participation was led by a performance engineer whose total involvement was about 20 hours. Normal shift operators performed the testing in the plant without disturbance to their duties. The consultant's applied time was about 80 hours including report writing. The latter is expected to be considerably less for future testing thanks to the experience gained.

### *Benefits*

Discussions with potential test participant showed the testing recommended by NERC to be very demanding and something they would only perform if forced to. Only the testing of the continuous Voltage or VAR control was judged simple enough for regular demonstration of satisfactory performance. The metrics for this service, now suggested in NERC's Reference Document, could be met by the generator tested.

A lesson learned was that data recording "by exception", i.e. only recording data when a value goes outside a preset dead band, can give a very distorted picture if the dead band is set too large for the study being conducted.

# 4
# EFFECTIVENESS OF FUTURE TESTING

Based on experience from the tests described above EPRI has found that effective testing can be promoted by clear description and understanding on the items discussed below. Use of this template should get the process pointed in the right direction.

It is strongly recommended to achieve clear definition or understanding of the following areas. Each one is discussed in some detail below.

## Definition and Objective of Testing

1. IOS (ancillary service) to be evaluated, NERC definition, document and rev. date.
2. Certification and or Performance test; metrics to be used
3. Unit to be tested

Owner's responsibilities:

1 Preparations, instructions to power plant, pre-test visit by subcontractor required?

2 Designate test leader and support personnel

3 Instrumentation, data acquisition and recording

4 Schedule

EPRI's team responsibilities:

a. Test procedure and instructions

b. Check-out list

c. Personnel on site for test, if required

d. Data analysis and report

## Terms of Testing

Contract issued by owner using normal terms and conditions; must limit consultant to conducting test without guarantee of unit performance and cover:

a. Liability for plant and equipment, (test to be conducted by owner at his risk)

b. Terms for EPRI's team personnel admittance to plant

c. Confidentiality of proprietary information

d. Terms of payment including provisions for delays

### IOS (Ancillary Service) To Be Evaluated, NERC Definition, Document And Rev. Date

Terminology is not consistent between FERC and NERC even for the same services. For example: Load Following and Black Start are not considered Ancillary Services by FERC. NERC has issued several drafts of Policy 10, which is currently classified as a "Reference Document". At the time of writing, NERC's task force is continuing its work on this document and may issue revisions later. Hence it may be important to note revision date of the Reference Document when planning a test.

### Certification and or Performance Test

Certification testing has the objective to demonstrate the capability of a generating unit to deliver an ancillary service according to requirements defined by the receiver of the service, (Operating Authority, Independent System Operator or similar). A contract on providing an ancillary service may require certification.

Performance testing has the objective to demonstrate, over a period of time, the quality of service provided. The metrics to be used may have significant impact on the measured quality. A contract on providing an ancillary service may have payment provisions tied to the performance. It is important for a successful test that all parties have a clear understanding of what the test is expected to demonstrate.

### Unit To Be Tested

The owner should be encouraged to clarify the performance criteria to be used. An example will best explain this: for Load Following, the maximum loading and un-loading rate must be defined as well as the load range within which these can be met. Possibly also required are maximum acceleration rates and jerk rates up and down. Further to be defined is the operating mode for the unit, for a steam unit for example fixed or sliding pressure, and settings for a coordinated boiler turbine generator control system.

### Owner's Responsibilities

There is sometimes inadequate communication between a regional or headquarters organization wishing to conduct the test and the personnel in the power plant.

Items a.-d. are areas that our experience has shown to require careful attention.

a. Preparations, instructions to power plant, pre-test visit:

A successful test depends strongly on above factors. It is particularly important to gain the plant's acceptance of a directive from "headquarters". The best way to clarify these factors is during a pre-test visit. If this can not be arranged, several hours must be scheduled before the actual test to go over the items listed.

b. Designated test leader and support personnel:

It is very beneficial if the test leader has some business or personal interest in the outcome of the test. Communication with the plant should go via this person.

c. Instrumentation, data acquisition and recording:

Instrumentation in modern power plants can be very refined and include very fast recording of hundreds or even thousands of data points. For a successful test it is necessary to pay close attention to such items as: label or "tag" of each variable; is it the one that needs to be recorded? - frequency of recording; watch out for data compression techniques, e.g. recording only when a variable goes outside a dead band. Generate and check out a data template before the test.

d. Schedule:

Testing may strain the plant and/or the local grid. Make sure the plant and its transmission system (AGC) understand the magnitude and rate of load changes and have them select a time of day during which they can be accommodated.

### *EPRI's responsibilities.*

Section 6 contains a sample of test procedures and checkout list. It is our experience that these must be carefully tailored and reviewed by the test leader.

### *Terms of testing.*

a. Most utilities recognize that testing of the type offered here must take place at their risk and that they must carefully review all planned operational procedures, and changes in load and other operating parameters. But at one utility clearing up these terms took a very long time and delayed the test.

b. It must be made absolutely clear that the unit is under the control of the owner at all times and he must have agreed to all steps of the testing in advance. All operational inputs are to be made by plant personnel. The owner can and must refuse to perform procedures with which he does not agree, and he can terminate a test procedure at any time.

c. The terms for EPRI team personnel's presence in the plant must be cleared up. Our personnel must follow established rules for subcontractors and other visitors. But we cannot accept any liability for damage to the plant and equipment or any adverse effect to the grid, nor for any other consequential damage. Nor can we be responsible for the unit achieving expected performance or meeting certification requirements.

d. Testing may disclose performance limitations or discrepancies that affect a unit's economic or contractual performance. Some utilities, especially those in a deregulated environment, may not wish such information disclosed by word of mouth or in written reports. When this is the case, definition and handling of proprietary information must be covered contractually.

## Data Reduction

### Regulation and Load Following

For this IOS the data analysis was fairly demanding. Details, together with a template suitable for implementation in spreadsheet format, may be found in Section 6. This calculation system is also available on CD-ROM, with annotations, ready for loading into a PC (equipped with Excel™) for use in evaluating new test results. To obtain, contact Nick Abi-Samra at nabisamr@epri.com, or 650 855 1022.

### Contingency Reserves – Spinning and Supplemental

The data analysis for this IOS consisted in plotting and comparing the achieved load reserves to those declared. Examples of the "Target" and actually achieved reserves may be found in Appendix C.

### Reactive Power Supply from Generation Sources

The data were captured at one-second intervals and transferred to an Excel™ file whose plotting routine was used to create a graph of the data and evaluate the rate of changes. An example of MVAr response is shown in Appendix C.

### Black Start

Because this test had been performed independently before EPRI's interest in the testing, we did not gain any experience in the data acquisition or reduction. The data were acquired mostly with existing instrumentation and sequence of event recorders, supplemented by pen or digital recorders. For details, please refer to the original report, Ref. 5.

# 5
# EXAMPLES OF CHECK LISTS, TEST PROCEDURES AND DATA LISTS

## Regulation and Load Following Measurements

| | |
|---|---|
| Note: | These lists were written for use by the generator (unit) owner in preparing for certification and performance testing. |

## Objectives

The Testing shall demonstrate compliance of a generating unit to supply Regulation and Load Following IOS (Integrated Operation Service = ancillary service) in accordance with NERC "Reference Document Interconnected Operations Services, date March 28-29, 2001. Following successful testing, the owner of the generating unit should have a procedure, knowledge and practice to enable him to qualify additional units without EPRI or consultant support. Assuming prior understanding with the Operating Authority (AO), the testing could lead to certification.

## Check Lists

### *Pre-Test Check List*

- Is tele-metering of actual power output (MW or kW) to Control Area in service and capable of transmitting data at required interval and accuracy (Recommendation: equal or better than integer MW for units over 100 MW)?
- Is communication link between unit and Control Area operational and capable of receiving load command signals and transmitting maximum and minimum output available as well as service status of unit?
- Is voice communication link between unit and Control Area in service and capable of providing primary (load following) and backup communication
- Is unit in an operating mode that can respond automatically to changes in load demand (MW)?
- Is unit in an operating mode that enables it to change load at the declared rates (and accelerations, if applicable) and between the declared upper and lower limits?
- Is the data acquisition system in service and capable of storing the required data (such as time stamped load commands, load changes, actual load, and unit status) at required interval and accuracy and can the data be accessed and extracted in machine readable form?

- Is there agreement with the Control Area to perform the testing and accept the load changes as well as the risk of unexpected load responses?

### General Testing Steps

Regulation and Load Following testing are similar. Quoting from the “Reference Document”: “The principal difference is the duration of the test and the frequency and period of signal changes.”

#### Regulation Certification Check List

Has the 60-minute test period been agreed upon between the unit and the Control Area?

Has the character (raise, hold, lower) of load command signal to be transmitted to the unit been agreed upon? Including the requirement that each signal shall remain unchanged for at least 1 minute and that the command signal must stay within the capability limits of the unit (high, low, ramp rate)?

Is it intended that a real certification shall result from this test? In that case, has the Operating Authority agreed to this?

#### Load Following Certification Check List

Has the 150+ minute test period been agreed upon between the unit and the Control Area?

Has the character (random raise, hold, and lower) of load command signal to be transmitted to the unit been agreed upon? Including the requirement that each signal shall remain unchanged for at least 10 minutes and that the command signal must stay within the capability limits of the unit (high, low, ramp rate)?

Is it intended that a real certification shall result from this test? In that case, has the Operating Authority agreed to this?

### Regulation and Load Following Performance Evaluation

The quantity to be evaluated is the SCE = Supplier Control Error = Pa – Ps, where:

- Pa = Actual metered power (MW), and
- Ps = Sum of all schedules transmitted to the unit at each sampling period.

To ascertain that the SCE can be calculated, the following should verified:

### Performance Evaluation Check List

Check that that the recordings of the data acquisition system are synchronized and accurate to allow the formation of instantaneous and time averaged values of SCE (i.e. 1, 10 minute and 1 hr averages).

Has a test sample been taken (for example during normal dispatched operation) for evaluation and verification, in the results template, of satisfactory resolution in the data?

Is there an understanding between the unit and the Control Area about min. and max load, limits on up and down rates and limits on up and down acceleration rate, so that the actual command signals received can be checked to verify that they are within the criteria?

### Data to be Acquired

The data to be acquired are identical for Regulation and Load Following. The difference between these two IOSs lies in the command signals received and evaluation of performance. Following signals are needed:

1. Time stamp for each load demand or load pulse received from the AGC (every 4-6s), preferably given in "system time". Same time stamp applied to data items 5) – 9) below.
2. Status signal that the unit (IOS source) is in "automatic" and ready to respond to AGC commands.
3. AGC demand signal to the unit (IOS source) in kW, or
4. AGC pulse change signal (governing signal) in +/- kW.
5. Unit (IOS source) set point in kW.
6. Unit (IOS source) actual power in kW.
7. Unit auxiliary power in kW, or in place of 6) and 7):
8. Unit (IOS source) net kW delivered to system..
9. System frequency measured at unit (IOS source).
10. Unit (IOS source) current maximum capability, kW.
11. Unit (IOS source) current minimum capability, kW
12. If applicable, recording of verbal Load Following schedule signals in kW, with nearest half-minute time indication.

### Specific Test Steps

The main steps are as follows, adapted as appropriate, for Regulation and Load Following

1. Complete pre-test check list.
2. Define minimum and maximum capabilities (kW) for the unit (IOS source) to be evaluated.
3. Define ramp rate limits up as well as down (kW/min).

4. Define acceleration limits in both directions (kW/min$^2$). Note: for items 2), 3) and 4) it should be kept in mind that these limits must be realistic, attainable and not put undue strain on the unit or pose significant risk of malfunction.

5. Agree with system operator about times for the testing, including the duration of each test, min. 60 minutes for Regulation, min. 150+ minutes for Load Following.

6. Ascertain that the system operator recognizes the load change requirements, i.e. 1 minute steady for Regulation, 10 minutes steady for Load Following (may be transmitted by voice).

7. Work with the system operator to define the "sequence of random control signals" to be sent to the unit, judiciously to ensure that signals will actually place the unit under test in sufficiently demanding load changes. This to ensure that the unit truly is certifiable.

8. Place the unit in the specified operating mode (turbine and boiler) at the agreed upon time for Regulation. Make sure data acquisition system is ready and initialized, and await the begin of test signals.

9. During the test period, supervise the procedure and take corrective action if required.

10. Do similar for the Load Following test.

11. Extract data from data acquisition system and make preliminary evaluation to ensure that data is satisfactory.

### Deliverables

The unit owner will make available, free of charge, the following equipment/ instrumentation, services and data:

- All instrumentation of "station type" for measurement of quantities specified, identified per unit nomenclature and tag as judged necessary. One-line diagram of the test set-up.
- Calibration records of instrumentation used to ensure satisfactory accuracy.
- Data acquisition equipment with sufficient speed, accuracy and storage capability for the data during the test sequences specified.
- All test personnel and any extra shift personnel deemed necessary for the testing.
- Participation in pre-test and post test meetings as required.
- Test instructions, as required, to participating utility personnel.
- Data files on machine readable medium, in mutually agreed upon format for loading into Excel™ evaluation templates prepared by the subcontractor.
- Summary of effort expended by the utility on testing.
- Any limitations on subcontractor's use of the data in report(s) on the Ancillary Measurement Project to be delivered to the utility per contracts between EPRI, unit owner and subcontractor.

Subcontractor will deliver to the unit owner the following services and data/reports:

- Participation in pre-test meeting to review detailed test plan and asses accuracy of proposed instrumentation, if required.
- Attend actual testing if judged necessary.
- Post-test meeting (if required) to evaluate satisfactory data.
- Test plans and data lists mutually agreed upon.
- Data reduction per NERC's recommended criteria for preliminary evaluation by the unit owner.
- Unit specific report on testing demonstrating that the unit met certification and performance criteria or identifying shortcomings as the case may be. Included will also be special experiences or recommendations resulting from the testing.

## Operating Reserve-Spinning and Supplemental

### *Step-by-Step Procedure*

#### Preparations

- Ascertain that the Metering and Communication specified in draft Policy 10 (Appendix 10B items 1.1, 1.2 and 1.3) are available and active.
- Select the reserve capacity to be demonstrated based on achievable loading rate for 10 minutes; for example 6 (MW/min) * 10 (min.)= 60 MW. Also determine the load range within which this reserve capacity can be achieved, for example between 300 and 430 MW for a 500 MW unit. Determine the approximate load level at which the demonstration of reserve shall take place; for example 350 MW.
- If the reserve is to be implemented by dispatch signal from the AGC (area generation control), arrange with the AGC for the loading ramp (10-X minutes), maintaining of reserve (20 minutes), unloading ramps (10 minutes), and maintaining prior load (at least 20 minutes) to be generated and dispatched to the unit at an agreed upon time. Total duration of this sequence is about 60 minutes. Two test sequences are desired.
- If the reserve is to be implemented locally, following verbal command from the AGC, select the proper load ramp and load target commands to be input by the operator on the local control panel. Obtain assurance from the AGC that the load changes will not upset the system.
- Determine the operating mode for the unit during the test, for boiler and turbine and the coordinated BTG control (if available), as well as for the generator voltage control. Make sure all sensors are active and calibrated satisfactorily, and that control systems are well lined up and tuned.
- Arrange for the required data to be measured and recorded by the unit computer or data acquisition system (often located in the "DCS"), at intervals as specified below.

- Make the testing known to interested and affected people and organizations. Instruct operators and other participating people. Review any risks with relevant people and agree upon action if the unit should not perform as expected.

### Implementation

1. Complete pre-test check list.
2. Bring the unit to be tested to the load from which the reserve is to be demonstrated. Put the controls and interfaces into the proper modes.
3. Make sure all boiler and TG supervisory and protection systems are active and working correctly.
4. Activate the data acquisition and recording system. Obtain some steady state data to verify that everything is working.
5. Verify that the AGC is ready for the test. Initiate test sequence (if reserve is activated locally) or wait for AGC to determine suitable time for initiation as agreed upon.
6. Monitor visually on instrumentation the progress of the testing to see that the loading and unloading sequence is being implemented.
7. Observe boiler and turbine supervisory instrumentation. Note abnormal or extreme values of critical parameters such as steam pressures and temperatures, boiler drum level. Take corrective action if an unacceptable situation occurs.
8. Extract data from the data acquisition system and verify that all required data were recorded, and if so, proceed to next test or terminate testing and return unit to normal service.

### Data to be Acquired

The data to be acquire are identical for Spinning and Supplemental Reserve. Following signals are required:

1. Time stamp on each load demand or load pulse received from AGC (preferably in the range of every 5-10 sec.). Same time stamp must be applied to all data items 3-8 below.
2. Status signal that the unit is in “automatic” and ready to respond to AGC commands, or that the unit is in suitable local control mode.
3. AGC load command signal to the unit in kW, or
4. AGC pulse load change signal (governing signal) in +/- kW, or
5. Loading ramp and target load if reserve is activated locally.
6. Unit load set point in kW/MW

7. Unit actual load in kW/MW

8. System frequency measured at the unit, Hz.

9. Declared current maximum capability of unit, MW.

10. Declared current minimum capability of unit, MW.

11. Declared loading/unloading rate, MW/min for Operating Reserve.

12. Record of any verbal communication between AGC and unit used to implement load sequence.

13. Recording of extreme values of critical steam and boiler parameters, as agreed upon or observed.

Note: "Unit Load" (items 3-6 above) is to be understood in the terms used between the unit (power station) and the dispatch control (AGC). For the reporting of the testing, the role of the unit (power station) auxiliary power consumption must be understood. Is the unit auxiliary power subtracted from the nominal "unit load" or not? How is the station general auxiliary load handled? Is it part of the "system" load?

## Reactive Power Supply Test Procedure

1. Determine that the required telemetry is provided to the Operating Authority.

2. Confirm that primary and alternate means exist for the Operating Authority to convey operating schedules.

3. Arrange for collection of the data required to assess the performance of the testing.

4. Determine the dynamic model data for the excitation control system. Testing is best performed at a variety of operating points in both open-circuit and on-line conditions. A number of industry standards and practices are relevant to these tests (refs. 6 to 9).

    a. Determine and validate mathematical definitions for each function within the AVR (or power factor controller, etc.). Manufacturer's literature generally provides equations or graphs that can be used to interpret hardware settings. However, more precise definitions can be obtained by testing. Variations in equipment operation due to aging and failures can be resolved by testing. Many of the AVR functions may be tested with the generator shut down if suitable power sources and test equipment is available. Voltage-driven functions may be tested with the generator on open-circuit where voltage and frequency can be changed more easily. Current-driven functions can be tested with the generator shut down and then validated at suitable operating points with the unit on-line. Many of the functions can be tested on line with reduced settings assuming off-line testing determines the mathematical relationships for the settings.

b. Determine and validate mathematical definitions for each function with the PSS (or other supplementary control). The tests to determine these definitions can typically be performed at normal load but with the PSS out of service.

c. Record the open-circuit step response of the excitation control system including at least the responses of generator field voltage and generator terminal voltage (include the exciter field voltage and field current when applicable). Responses of damping or stabilizing functions can be very useful in model parameter selection if they are available.

d. Record the on-line step response of the excitation control system recording the same data points specified for Step (C). Care must be exercised if large steps are used to force the exciter to ceiling.

e. Record the maximum and minimum values for each excitation control system quantity when driven by a low frequency sinusoidal source producing a small (1 to 3 percent) change in generator terminal voltage. If time permits, record this data in both open-circuit and normal load conditions. The results are more important for normal load conditions.

f. Record the on-line frequency response of the excitation control system for the PSS input to the AVR. This is the uncompensated response used in PSS adjustment. It is performed with the PSS out of service.

g. Record the on-line frequency response of the PSS with all compensation parameters installed. This is a response of just the PSS block of the excitation control system. It is used to validate the PSS model.

h. Record the compensated frequency response of the PSS and the excitation control system with the input to the PSS driven by the test equipment and disconnected from the transducer.

i. Record voltage deviation and frequency deviation for several minutes during normal operation (with real power near full load if possible).

5. Determine the gross and net reactive power capability. Values selected for real power output must be distributed over the range of normal operation. The operating conditions should be as close to normal as possible. Coordination with other units may be required to maintain scheduled voltage. Testing should be scheduled during periods when system conditions can accommodate the variations in real and reactive power. Testing should be scheduled recognizing the risk of unit load rejection associated with such testing.

   a. Determine the maximum sustained reactive power capability as a function of real power output, generator and system voltages, and rotor and stator temperatures. At over-excited operating points the tests must be conducted for a minimum of two hours or until temperatures have stabilized. At under-excited operating points the tests must be conducted until unit output has stabilized.

   b. Determine the factor limiting reactor power output for step A. Be aware of limits imposed external to the excitation control system (including supervisory computer control).

   c. Record the real and reactive power requirements of auxiliary loads for step A.

   d. Record pertinent system, unit and operating conditions.

e. Repeat steps A. through D. at three over-excited operating points and at three under-excited operating points.

6. Determine the response to a change in schedule (either voltage or reactive power schedule).

   a. Do not make any changes in the scheduled value for a period of 15 minutes prior to the change scheduled for step (B).

   b. Make a change in the voltage or reactive power schedule. The size of the change should be large enough to produce a response significantly larger than any background variations in voltage or reactive power. Steps of 2 or 3 percent in voltage of 5 to 10 percent of rated MVA in reactive power are typical.

   c. Repeat steps (A) and (B) with a change in the opposite direction.

   d. Repeat Steps (A) through (C) at least once. The objective is to ensure that a typical response is recorded.

   e. If there is any suspicion of excitation control system instability (or "hunting") it may be necessary to monitor generator voltage and/or reactive power output with equipment that can accurately reproduce frequencies to 10 Hertz or higher. Repeat steps (A) through (D) as necessary.

## Reactive Power Supply Data Collection Requirements

The table on the following page identifies the data associated with each test. Only the data collected using existing station instrumentation is included in the table.

**Table 5-1**
**Data Points for Reactive Power Supply Testing**

| Data Point | Reactive Capability (Step 5) | Dynamic Model (Step 4) | Schedule Response (Step 6) |
|---|---|---|---|
| Gross Reactive Power Output | X | X | X |
| Gross Real Power Output | X | X | |
| Generator Terminal Voltage | X | X | X |
| System Voltage | X | X | |
| Auxiliary Reactive Power Load | X | | |
| Auxiliary Real Power Load | X | | |
| Scheduled Voltage | | X | X |
| Scheduled Reactive Power | | X | X |
| Scheduled Real Power | | X | X |
| Ambient Air Temperature | X | | |
| Rotor Temperature | X | | |
| Stator Temperature | X | | |
| Rotor/Stator Coolant Temperatures (optional) | X | | |

Other information is required in addition to the data in the table. The temperature rise for which the generator rotor and stator was designed is required. Existing capability curves are required. Excerpts from operator's logs and from event recording systems are required for the period of the certification testing. It is especially important to record any special conditions that may influence the results of the testing. A listing of the excitation control system settings is required including settings for each AVR and PSS module. The settings of protective devices, such as under-frequency or loss-of-field devices, are required. The details of supervisory control equipment operation are required including block diagrams of limiting and controlling functions. It is best to disable such supervisory control during the testing if possible.

The required machine parameters are: armature resistance, field resistance, armature time constant, quadrature-axis sub-transient open-circuit time constant, direct-axis sub-transient open-circuit time constant, direct-axis transient open-circuit time constant, direct-axis transient short-circuit time constant, direct-axis sub-transient short-circuit time constant, direct-axis synchronous reactance, direct-axis transient reactance, direct-axis sub-transient reactance, quadrature-axis synchronous reactance, quadrature-axis transient reactance, negative sequence reactance, zero sequence reactance, and leakage reactance.

# 6
# DATA EVALUATION TEMPLATES WITH SAMPLE TEST DATA

## Regulation and Load Following Measurements

The data from the certification testing were evaluated in spread sheet templates prepared in Excel™ format. Following are descriptions of the template columns and data included in this Appendix.

To hold all the measurements acquired (e.g. 2 ½ hours of readings taken every 6 s = 1500 entries) the column depth of the spread sheet is so large that it can not be reproduced in this report. Also, the row length is so large that the spread sheet takes several pages to reproduce. In the following are only shown the headings of all columns and a small sample of data. Below is a detailed description of the template, identified by the heading of each sheet.

## Ancillary Services – Regulation

### *Regulation Summary Sheet*

- IOS Supplier requirements – this is a check-list of the Policy 10 requirements together with site findings.
- Test Method – shows the duration and period between each load command (pulse).
- Performance Criteria – declared, scheduled and actual load, ramp rate and acceleration are summarized for comparison here.
- Statistical Results – show the value of quantities specified in Policy 10.

### *Sample Test Data*

This sheet shows a few minutes of data as acquired from the station data logging computer.

### *Data Entry Processing*

The columns of this sheet are:

1. 1 min. Period Identifier - number used to identify each minute for averaging.

2. Number of entries/1 min. period - used in determining 1 min. averages
3. Logtime. - Time stamp for each data entry.
4. Pa Actual Gen. MW. – Power measurement for each data point.
5. Ps Scheduled Gen. MW. – Scheduled power for each data point.
6. SCE=Pa-Ps, Supplier Control Error, MW – column 4 minus column 5
7. |SCE| MW – absolute value of column 6.

### *Data Evaluation – 1 min. period*

The columns of this sheet are:

1. Average (Pa) MW – average of Pa for the minute identified in column 2 above.
2. Average (Ps) MW - average of Ps for the minute.
3. Average (SCE) MW – average supplier control error for the minute.
4. StDev(SCE) MW – standard deviation of SCE for the minute.
5. Ps max MW – maximum of Ps during the minute.
6. Ps min MW – minimum of Ps during the minute
7. |SCE| max MW – maximum absolute value of supplier control error during the minute.
8. |SCE| min MW – minimum absolute value of supplier control error during the minute.
9. Ps Ramp rate MW/min – scheduled ramp rate during the minute.
10. Ps Acceleration rate MW/min2 – scheduled acceleration rate during the minute.
11. Pa Ramp rate MW/min – actual ramp rate during the minute.
12. Pa Acceleration rate MW/min2 – actual

### *Data Evaluation – 1 hr test period*

The columns of this sheet are:

1. Correlation coefficient – between Pa and Ps calculated for the hour, in per unit (p.u.).
2. Pa max MW – maximum actual load during the hour.
3. Pa min MW – minimum actual load during the hour.

4. Ps max MW – maximum scheduled load during the hour.
5. Ps min MW – minimum scheduled load during the hour
6. |SCE| max MW – maximum absolute value of supplier control error during the hour.
7. |SCE| min MW – minimum absolute value of supplier control error during the hour
8. Ps max Ramp rate MW/min – maximum scheduled ramp rate during the hour.
9. Ps min Ramp rate MW/min – minimum scheduled ramp rate during the hour.
10. Ps max Acceleration rate MW/min2 - maximum scheduled acceleration rate during the hour.
11. Ps min Acceleration rate MW/min2 - minimum scheduled acceleration rate during the hour.
12. Pa max Ramp rate MW/min – maximum actual ramp rate during the hour.
13. Pa min Ramp rate MW/min – minimum actual ramp rate during the hour.
14. Pa max Acceleration rate MW/min2 – maximum actual acceleration during the hour.
15. Pa min Acceleration rate MW/min2 – minimum actual acceleration during the hour.
16. Avg. SCE MW – average supplier control error during the hour.
17. StDev(SCE) MW – standard deviation of supplier control error during the hour.
18. Avg. |SCE| MW – average of absolute value of supplier control error during the hour.
19. StDev(|SCE|) MW – standard deviation of absolute value of supplier control error during the hour.

### PS Ramp rate (dt) and Acceleration rate, columns 1 and 2

This tabulation shows a 3 minute sample of scheduled rates calculated for each dt (6 s). It illustrates the extreme values achieved over very short periods. The acceleration rates are within the declared limits of the unit (+/- 5 MW/min), but the acceleration rates are occasionally far outside the declared limits (+/- 10 MW/min2).

### Pa Ramp rate (dt) and Acceleration rate, columns 3 and 4

This tabulation shows equivalent values for actual rates. The unloading ramp rates are steeper than the declared capability of the unit. Both negative and positive acceleration rates exceed the declared numerical capability of the unit.

### Scheduled Output and Actual Output

This graph illustrates the two outputs versus time over one hour.

### Supplier Control Error (SCE) MW versus Time

This graph illustrates the swing of SCE between positive and negative values as the scheduled load ramps up and down.

**Ancillary Services - Regulation**

**Certification Criteria**

| **IOS Supplier requirements** | | |
|---|---|---|
| Responsive to instructions of Operating Authority (automatic) | y/n | y |
| Responsive raise/lower signals of Operating Authority | y/n | y |
| Approved communication service between IOS Resource control interface and Control Area | y/n | y |
| Approved voice communication service between IOS Resource operator and Control Area operator | y/n | y |
| Data acquisition system capable of storing data at required intervals | y/n | y |

| **Test Method** | | |
|---|---|---|
| Test duration | min | 60 |
| Period between signal change requests (signal rate or dt) | sec | 6 |

**Performance Criteria**

| | | Declared | Recorded |
|---|---|---|---|
| Minimum actual output (Pamin) | MW | 130 | 0.0000 |
| Maximum actual output (Pamax) | MW | 170 | 0.0000 |
| Minimum scheduled output (Psmin) | MW | | 0.0000 |
| Maximum scheduled output (Psmax) | MW | | 0.0000 |
| Abs. Minimum Supplier Control Error(\|SCE\|min) | MW | | 0.0000 |
| Abs. Maximum Supplier Control Error(\|SCE\|max) | MW | | 0.0000 |

| | | Declared | Scheduled | Actual |
|---|---|---|---|---|
| Ramp down limit (Rmax) | MW/min | -5 | 0.0000 | 0.0000 |
| Ramp up limit (Rmin) | MW/min | 5 | 0.0000 | 0.0000 |
| Maximum acceleration down (Jmin) | MW/min^2 | -10 | 0.0000 | 0.0000 |
| Maximum acceleration up (Jmax) | MW/min^2 | 10 | 0.0000 | 0.0000 |

**Statistical Results (during test period)**

| | | |
|---|---|---|
| Avg. \|SCE\| | MW | 0.0000 |
| StDev(\|SCE\|) | MW | 0.0000 |
| Avg SCE | MW | 0.0000 |
| StDev(SCE) | MW | 0.0000 |
| Correlation Coefficient between Avg. Ps and Avg. Pa | | 0.0000 |

**Figure 6-1**
**Ancillary Services Regulation**

*Data Evaluation Templates With Sample Test Data*

| Logtime | Set Point MW | Gross Output MW | Aux. Load MW | Net output MW | Frequency Hz | Max load MW | Min Load MW | AGC in Automatic |
|---|---|---|---|---|---|---|---|---|
| | LDC10101 | AI10284 | AI10285 | AO10873 | AI10286 | AO10875 | AO10876 | DO12161 |
| 29-Sep-99 10:00:00 | 135.2951965 | 135.1997375 | 8.218424797 | 126.9875 | 59.88555527 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:06 | 135.2992249 | 135.4112396 | 8.221804619 | 127.2073 | 59.87334824 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:12 | 135.3032532 | 135.3279114 | 8.225185394 | 127.1157 | 59.87639999 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:18 | 135.3072815 | 135.148468 | 8.22856617 | 126.9326 | 59.87945175 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:24 | 135.3113098 | 134.9369812 | 8.231945992 | 126.7251 | 59.87334824 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:30 | 135.3153381 | 134.8728943 | 8.235326767 | 126.6457 | 59.87304688 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:36 | 135.3193665 | 134.8857117 | 8.238706589 | 126.6396 | 59.87273788 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:42 | 135.3193665 | 134.9497986 | 8.242087364 | 126.6823 | 59.87243271 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:48 | 135.3193665 | 134.8344421 | 8.24546814 | 126.5542 | 59.87212372 | 179.996 | Over Range | on |
| 29-Sep-99 10:00:54 | 135.3193665 | 134.5524445 | 8.248847961 | 126.2978 | 59.87182236 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:00 | 135.3193665 | 134.5716705 | 8.179265976 | 126.3344 | 59.87151718 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:06 | 135.3193665 | 134.5075836 | 8.16736412 | 126.2978 | 59.87121201 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:12 | 135.3193665 | 134.9369812 | 8.155461311 | 126.7617 | 59.87090302 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:18 | 135.3193665 | 134.9113464 | 8.143559456 | 126.7373 | 59.87060547 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:24 | 135.3193665 | 135.3855896 | 8.131656647 | 127.2256 | 59.87029648 | 179.996 | Over Range | on |
| 29-Sep-99 10:01:30 | 135.3193665 | 135.6419525 | 8.131656647 | 127.4819 | 59.8699913 | 179.996 | Over Range | on |

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| | | **Data Entry Preprocessing** | | | | |
| **1 min. Period Identifier** | **Number of entries/ 1 min. period** | **Logtime** | **Pa Actual Gen. MW** | **Ps Scheduled Gen. MW** | **SCE=Pa-Ps Supplier Control Error MW** | **\|SCE\| MW** |
| 0 | | 29-Sep-99 10:00:00 | 135.1997375 | 135.2951965 | -0.0954590 | 0.0954590 |
| 0 | | 29-Sep-99 10:00:06 | 135.4112396 | 135.2992249 | 0.1120147 | 0.1120147 |
| 0 | | 29-Sep-99 10:00:12 | 135.3279114 | 135.3032532 | 0.0246582 | 0.0246582 |
| 0 | | 29-Sep-99 10:00:18 | 135.1484680 | 135.3072815 | -0.1588135 | 0.1588135 |
| 0 | | 29-Sep-99 10:00:24 | 134.9369812 | 135.3113098 | -0.3743286 | 0.3743286 |
| 0 | | 29-Sep-99 10:00:30 | 134.8728943 | 135.3153381 | -0.4424438 | 0.4424438 |
| 0 | | 29-Sep-99 10:00:36 | 134.8857117 | 135.3193665 | -0.4336548 | 0.4336548 |
| 0 | | 29-Sep-99 10:00:42 | 134.9497986 | 135.3193665 | -0.3695679 | 0.3695679 |
| 0 | | 29-Sep-99 10:00:48 | 134.8344421 | 135.3193665 | -0.4849244 | 0.4849244 |
| 1 | 10 | 29-Sep-99 10:00:54 | 134.5524445 | 135.3193665 | -0.7669220 | 0.7669220 |
| 0 | | 29-Sep-99 10:01:00 | 134.5716705 | 135.3193665 | -0.7476960 | 0.7476960 |
| 0 | | 29-Sep-99 10:01:06 | 134.5075836 | 135.3193665 | -0.8117829 | 0.8117829 |
| 0 | | 29-Sep-99 10:01:12 | 134.9369812 | 135.3193665 | -0.3823853 | 0.3823853 |
| 0 | | 29-Sep-99 10:01:18 | 134.9113464 | 135.3193665 | -0.4080201 | 0.4080201 |
| 0 | | 29-Sep-99 10:01:24 | 135.3855896 | 135.3193665 | 0.0662231 | 0.0662231 |
| 0 | | 29-Sep-99 10:01:30 | 135.6419525 | 135.3193665 | 0.3225860 | 0.3225860 |
| 0 | | 29-Sep-99 10:01:36 | 135.7701263 | 135.3193665 | 0.4507598 | 0.4507598 |
| 0 | | 29-Sep-99 10:01:42 | 135.8983154 | 135.3193665 | 0.5789489 | 0.5789489 |
| 0 | | 29-Sep-99 10:01:48 | 135.8085785 | 135.3193665 | 0.4892120 | 0.4892120 |
| 1 | 10 | 29-Sep-99 10:01:54 | 135.6611786 | 135.3193665 | 0.3418121 | 0.3418121 |
| 0 | | 29-Sep-99 10:02:00 | 135.6868134 | 135.3193665 | 0.3674469 | 0.3674469 |
| 0 | | 29-Sep-99 10:02:06 | 135.7252655 | 135.3193665 | 0.4058990 | 0.4058990 |
| 0 | | 29-Sep-99 10:02:12 | 135.6739960 | 135.3193665 | 0.3546295 | 0.3546295 |
| 0 | | 29-Sep-99 10:02:18 | 135.4112396 | 135.3193665 | 0.0918731 | 0.0918731 |
| 0 | | 29-Sep-99 10:02:24 | 135.3407288 | 135.3193665 | 0.0213623 | 0.0213623 |
| 0 | | 29-Sep-99 10:02:30 | 135.3086853 | 135.3193817 | -0.0106964 | 0.0106964 |
| 0 | | 29-Sep-99 10:02:36 | 135.2766418 | 135.3193665 | -0.0427247 | 0.0427247 |
| 0 | | 29-Sep-99 10:02:42 | 135.2189636 | 135.3193817 | -0.1004181 | 0.1004181 |
| 0 | | 29-Sep-99 10:02:48 | 135.3150940 | 135.3193665 | -0.0042725 | 0.0042725 |
| 1 | 10 | 29-Sep-99 10:02:54 | 135.1420593 | 135.3193665 | -0.1773072 | 0.1773072 |
| 0 | | 29-Sep-99 10:03:00 | 135.1164246 | 135.3193665 | -0.2029419 | 0.2029419 |

**Figure 6-2**
**Data Entry Preprocessing**

| | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| | | | | **Data Evaluation -1 min period** | | |
| **Logtime** | **Average (Pa) MW** | **Average (Ps) MW** | **Average (SCE) MW** | **StDev(SCE) MW** | **Psmax MW** | **Psmin MW** |
| 29-Sep-99 10:00:54 | 135.0120 | 135.3109 | -0.2989 | 0.2662 | 135.3194 | 135.2952 |
| 29-Sep-99 10:01:54 | 135.3093 | 135.3194 | -0.0100 | 0.5305 | 135.3194 | 135.3194 |
| 29-Sep-99 10:02:54 | 135.4099 | 135.3194 | 0.0906 | 0.2097 | 135.3194 | 135.3194 |
| 29-Sep-99 10:03:54 | 135.4064 | 135.3194 | 0.0871 | 0.5319 | 135.3194 | 135.3194 |
| 29-Sep-99 10:04:54 | 135.7528 | 135.2643 | 0.4885 | 0.4956 | 135.3194 | 135.2388 |
| 29-Sep-99 10:05:54 | 135.3757 | 135.2757 | 0.0999 | 0.6155 | 135.2791 | 135.2657 |
| 29-Sep-99 10:06:54 | 135.4942 | 135.2791 | 0.2152 | 0.5441 | 135.2791 | 135.2791 |
| 29-Sep-99 10:07:54 | 135.5109 | 135.2153 | 0.2956 | 0.6383 | 135.2388 | 135.1918 |
| 29-Sep-99 10:08:54 | 135.6525 | 135.3113 | 0.3412 | 0.1550 | 135.3194 | 135.2657 |
| 29-Sep-99 10:09:54 | 137.2964 | 137.7855 | -0.4890 | 0.2290 | 139.7305 | 135.9102 |
| 29-Sep-99 10:10:54 | 141.3401 | 142.3765 | -1.0364 | 0.2542 | 144.5203 | 140.2341 |
| 29-Sep-99 10:11:54 | 145.7885 | 146.7961 | -1.0076 | 0.6967 | 147.5726 | 145.0246 |
| 29-Sep-99 10:12:54 | 148.1720 | 149.0742 | -0.9022 | 0.5247 | 150.8625 | 147.5793 |
| 29-Sep-99 10:13:54 | 152.1035 | 151.6839 | 0.4196 | 0.5944 | 151.7823 | 151.2619 |
| 29-Sep-99 10:14:54 | 152.0388 | 151.6091 | 0.4297 | 0.4770 | 151.8293 | 150.8624 |
| 29-Sep-99 10:15:54 | 149.1099 | 148.7294 | 0.3805 | 0.3279 | 150.8624 | 146.6751 |
| 29-Sep-99 10:16:54 | 144.7503 | 144.2669 | 0.4834 | 1.0122 | 146.2835 | 143.0691 |
| 29-Sep-99 10:17:54 | 142.0608 | 142.9861 | -0.9253 | 0.1259 | 143.0473 | 142.9692 |
| 29-Sep-99 10:18:54 | 142.5719 | 143.2911 | -0.7192 | 0.3965 | 144.3095 | 142.9919 |
| 29-Sep-99 10:19:54 | 145.5568 | 146.4902 | -0.9334 | 0.5270 | 148.0493 | 144.5647 |
| 29-Sep-99 10:20:54 | 150.3798 | 150.7446 | -0.3648 | 0.3990 | 152.5410 | 148.5710 |
| 29-Sep-99 10:21:54 | 154.9817 | 154.9654 | 0.0163 | 0.8585 | 156.9387 | 152.9237 |
| 29-Sep-99 10:22:54 | 160.8635 | 159.2638 | 1.5997 | 0.6325 | 160.8597 | 157.4154 |
| 29-Sep-99 10:23:54 | 162.8534 | 160.8776 | 1.9758 | 0.3923 | 160.9515 | 160.8597 |
| 29-Sep-99 10:24:54 | 161.7002 | 160.8861 | 0.8141 | 0.2440 | 160.9873 | 160.5240 |
| 29-Sep-99 10:25:54 | 160.5447 | 158.7126 | 1.8321 | 1.0865 | 160.0607 | 157.3952 |
| 29-Sep-99 10:26:54 | 155.5012 | 155.6695 | -0.1684 | 0.4369 | 156.9118 | 154.3853 |
| 29-Sep-99 10:27:54 | 153.5109 | 154.3376 | -0.8267 | 0.6925 | 154.3766 | 154.3010 |
| 29-Sep-99 10:28:54 | 153.8272 | 154.6639 | -0.8367 | 0.4004 | 155.7369 | 154.2665 |
| 29-Sep-99 10:29:54 | 157.9885 | 157.9498 | 0.0386 | 0.5100 | 159.8526 | 156.2404 |
| 29-Sep-99 10:30:54 | 162.5276 | 162.1974 | 0.3301 | 0.6569 | 164.4834 | 160.0607 |
| 29-Sep-99 10:31:54 | 165.8935 | 166.5926 | -0.6991 | 0.3302 | 168.0035 | 164.9639 |
| 29-Sep-99 10:32:54 | 169.2303 | 170.4830 | -1.2527 | 0.7198 | 171.6199 | 168.5406 |

**Figure 6-3**
**Data Evaluation (Part 1)**

| 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|
| **\|SCE\|max MW** | **\|SCE\|min MW** | **Ps Ramp rate MW/min** | **Ps Acceleration rate MW/min^2** | **Pa Ramp rate MW/min** | **Pa Acceleration rate MW/min^2** |
| 0.7669 | 0.0247 | 0.0269 | 0.0298 | -0.7192 | -0.7991 |
| 0.8118 | 0.0662 | 0.0000 | 0.0000 | 1.2106 | 1.3451 |
| 0.4059 | 0.0043 | 0.0000 | 0.0000 | -0.6053 | -0.6725 |
| 0.8609 | 0.0630 | 0.0000 | 0.0000 | 1.1180 | 1.2422 |
| 0.9638 | 0.0211 | -0.0634 | -0.0705 | -1.4527 | -1.6141 |
| 1.1127 | 0.1755 | 0.0149 | 0.0166 | 1.8336 | 2.0374 |
| 0.8948 | 0.1225 | 0.0000 | 0.0000 | -0.5626 | -0.6251 |
| 1.2147 | 0.0015 | 0.0522 | 0.0580 | 0.7513 | 0.8347 |
| 0.5994 | 0.1816 | 0.0597 | 0.0663 | -0.3703 | -0.4114 |
| 0.8472 | 0.1468 | 4.2448 | 4.7164 | 3.9913 | 4.4348 |
| 1.4279 | 0.5353 | 4.7625 | 5.2917 | 4.0637 | 4.5153 |
| 1.9762 | 0.0226 | 2.8311 | 3.1457 | 3.9806 | 4.4229 |
| 1.8122 | 0.2219 | 3.6480 | 4.0533 | 3.3113 | 3.6792 |
| 1.2870 | 0.0133 | 0.5782 | 0.6424 | 1.2818 | 1.4242 |
| 1.0083 | 0.1024 | -1.0295 | -1.1439 | -0.1887 | -0.2097 |
| 0.9473 | 0.0870 | -4.6526 | -5.1695 | -4.6927 | -5.2141 |
| 1.6676 | 0.1315 | -3.5715 | -3.9684 | -4.9989 | -5.5544 |
| 1.1399 | 0.7655 | -0.0643 | -0.0715 | 0.0783 | 0.0870 |
| 1.2729 | 0.1077 | 1.4640 | 1.6267 | 0.8047 | 0.8941 |
| 1.5668 | 0.1471 | 3.8718 | 4.3020 | 5.2909 | 5.8788 |
| 1.0999 | 0.0164 | 4.4110 | 4.9011 | 3.3255 | 3.6950 |
| 1.3797 | 0.2500 | 4.4611 | 4.9568 | 5.4547 | 6.0608 |
| 2.3551 | 0.0873 | 3.8270 | 4.2522 | 5.0773 | 5.6414 |
| 2.7122 | 1.5009 | 0.1019 | 0.1133 | 0.4344 | 0.4826 |
| 1.2150 | 0.4953 | -0.4799 | -0.5333 | -0.4023 | -0.4470 |
| 3.4663 | 0.2228 | -2.9616 | -3.2907 | -4.5539 | -5.0599 |
| 0.7664 | 0.0308 | -2.8072 | -3.1191 | -3.6246 | -4.0273 |
| 1.6031 | 0.0021 | -0.0840 | -0.0933 | 0.1852 | 0.2057 |
| 1.5156 | 0.1221 | 1.6018 | 1.7798 | 0.9969 | 1.1077 |
| 1.1547 | 0.0262 | 4.0135 | 4.4594 | 4.2584 | 4.7315 |
| 1.3084 | 0.1104 | 4.9141 | 5.4601 | 4.9242 | 5.4713 |
| 1.2656 | 0.2897 | 3.3773 | 3.7525 | 2.2930 | 2.5477 |
| 1.9248 | 0.2066 | 3.4214 | 3.8016 | 5.5259 | 6.1399 |

**Figure 6-4**
**Data Evaluation (Part 2)**

| 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 |
|---|---|---|---|---|---|---|---|
| Pa Max. Ramp rate MW/min | Pa Min. Ramp rate MW/min | Pa Max. Acceleration rate MW/min^2 | Pa Min. Acceleration rate MW/min^2 | Avg. SCE MW | StDev(SCE) MW | Avg. \|SCE\| MW | StDev(\|SCE\|) MW |
| 6.1775 | -6.1739 | 6.8638 | -6.8599 | -0.0214 | 0.9138 | 0.7288 | 0.5508 |

Data Evaluation-1 hr test period

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Logtime | correlation coefficient | Pamax MW | Pamin MW | Psmax MW | Psmin MW | \|SCE\|max MW | \|SCE\|min MW | Ps Max. Ramp rate MW/min | Ps Min. Ramp rate MW/min | Ps Max. Acceleration rate MW/min^2 | Ps Min. Acceleration rate MW/min^2 |
| 29-Sep-99 10:59:54 | 0.9981 | 173.9351 | 134.5076 | 172.7100 | 135.1918 | 3.4663 | 0.0015 | 4.9141 | -5.2370 | 5.4601 | -5.8189 |

**Figure 6-5**
**Data Evaluation—1 Hour Test Period**

| | Ps Ramp rate & (dt) | Acceleration rate | Pa Ramp rate & (dt) | Acceleration rate |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| Logtime | Ramp rate MW/min | Acceleration rate MW/min^2 | Ramp rate MW/min | Acceleration rate MW/min^2 |
| 29-Sep-99 10:22:24 | 0.8057 | 25.5127 | 0.3845 | 18.5867 |
| 29-Sep-99 10:22:30 | 3.3569 | -16.7847 | 2.2432 | -0.0015 |
| 29-Sep-99 10:22:36 | 1.6785 | 67.8131 | 2.2430 | 0.0000 |
| 29-Sep-99 10:22:42 | 8.4598 | -76.5396 | 2.2430 | -14.7385 |
| 29-Sep-99 10:22:48 | 0.8058 | -8.0582 | 0.7692 | 21.1472 |
| 29-Sep-99 10:22:54 | 0.0000 | 0.0000 | 2.8839 | -17.3035 |
| 29-Sep-99 10:23:00 | 0.0000 | 0.0015 | 1.1536 | 6.4087 |
| 29-Sep-99 10:23:06 | 0.0002 | -0.0031 | 1.7944 | -7.0496 |
| 29-Sep-99 10:23:12 | -0.0002 | 0.0031 | 1.0895 | -29.4800 |
| 29-Sep-99 10:23:18 | 0.0002 | -0.0031 | -1.8585 | 39.0930 |
| 29-Sep-99 10:23:24 | -0.0002 | 0.0015 | 2.0508 | 22.4319 |
| 29-Sep-99 10:23:30 | 0.0000 | 0.0000 | 4.2940 | -7.0496 |
| 29-Sep-99 10:23:36 | 0.0000 | 8.7280 | 3.5890 | -55.1163 |
| 29-Sep-99 10:23:42 | 0.8728 | -8.2809 | -1.9226 | -43.5822 |
| 29-Sep-99 10:23:48 | 0.0447 | 0.0015 | -6.2808 | -2.2400 |
| 29-Sep-99 10:23:54 | 0.0449 | 0.0000 | -6.5048 | 33.3237 |
| 29-Sep-99 10:24:00 | 0.0449 | -0.0015 | -3.1725 | 15.0604 |
| 29-Sep-99 10:24:06 | 0.0447 | -0.0015 | -1.6664 | 20.5109 |
| 29-Sep-99 10:24:12 | 0.0446 | 0.0030 | 0.3847 | 8.3298 |
| 29-Sep-99 10:24:18 | 0.0449 | -0.0015 | 1.2177 | -23.7122 |
| 29-Sep-99 10:24:24 | 0.0447 | 0.0015 | -1.1536 | 2.5635 |
| 29-Sep-99 10:24:30 | 0.0449 | -0.0015 | -0.8972 | -0.0015 |
| 29-Sep-99 10:24:36 | 0.0447 | -42.7460 | -0.8974 | 21.7926 |
| 29-Sep-99 10:24:42 | -4.2299 | 38.2706 | 1.2819 | -0.0015 |
| 29-Sep-99 10:24:48 | -0.4028 | -42.2989 | 1.2817 | -15.0604 |
| 29-Sep-99 10:24:54 | -4.6327 | 42.2989 | -0.2243 | 0.0000 |
| 29-Sep-99 10:25:00 | -0.4028 | -46.3257 | -0.2243 | 18.2648 |
| 29-Sep-99 10:25:06 | -5.0354 | -0.0015 | 1.6022 | -12.1765 |
| 29-Sep-99 10:25:12 | -5.0356 | -0.0015 | 0.3845 | 4.4861 |
| 29-Sep-99 10:25:18 | -5.0357 | 46.3287 | 0.8331 | -64.7293 |
| 29-Sep-99 10:25:24 | -0.4028 | -8.7280 | -5.6398 | -72.4213 |
| 29-Sep-99 10:25:30 | -1.2756 | -29.5425 | -12.8819 | -5.1254 |

**Figure 6-6**
**PS Ramp Rate Acceleration Rate**

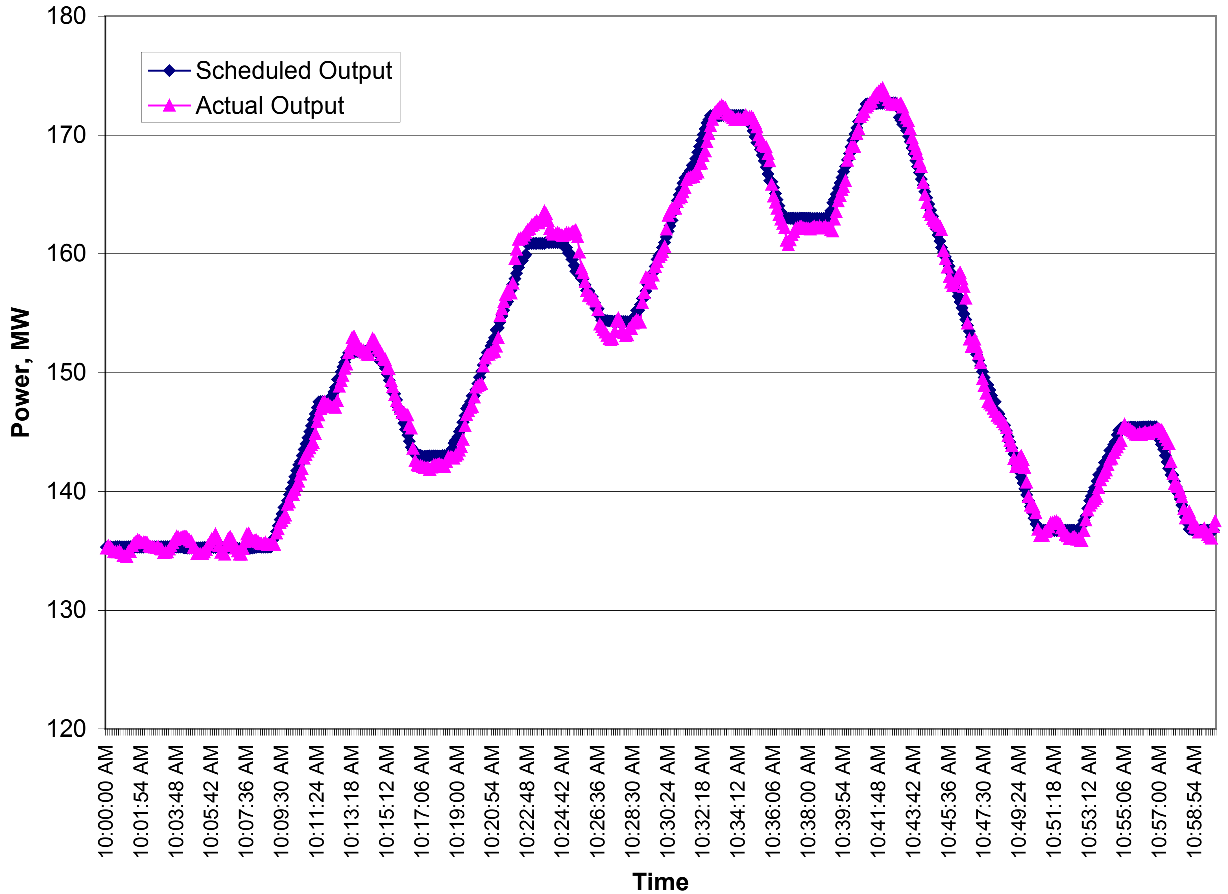



**Figure 6-7**
**Scheduled vs. Actual Output**

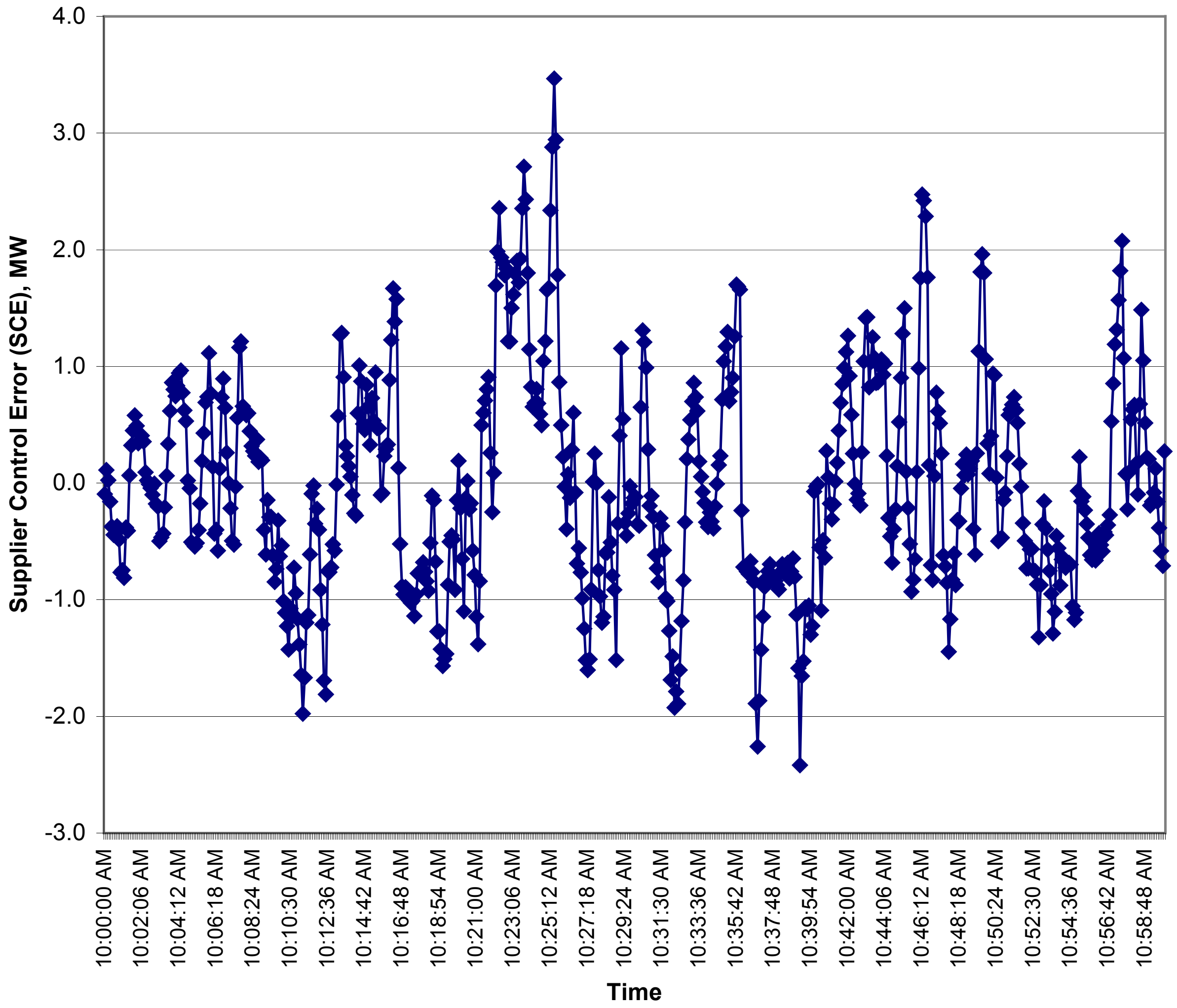



**Figure 6-8**
**Supplier Control Error (SCE)**

## Ancillary Services - Load Following

The template for this evaluation is identical to that for Regulation except it contains data for 150 minutes at 6 s interval. The individual sheets and columns are labeled exactly as for Regulation and need not be repeated. The comments on individual values given under Regulation are essentially also valid for Load Following. This is no surprise because the two tests were carried out with the same declared capabilities of the unit.

## Ancillary Services - Load Following

### Certification Criteria

| **IOS Supplier requirements** | | |
|---|---|---|
| Responsive to instructions of Operating Authority (automatic) | y/n | y |
| Responsive raise/lower signals of Operating Authority | y/n | y |
| Approved communication service between IOS Resource control interface and Control Area | y/n | y |
| Approved voice communication service between IOS Resource operator and Control Area operator | y/n | y |
| Data acquisition system capable of storing data at required intervals | y/n | y |

| **Test Method** | | |
|---|---|---|
| Test duration | min | 150 |
| Period between signal change requests (signal rate or dt) | sec | 6 |

### Performance Criteria

| | | Declared | Recorded | |
|---|---|---|---|---|
| Minimum actual output (Pamin) | MW | 130 | 134.9754 | |
| Maximum actual output (Pamax) | MW | 170 | 173.2365 | |
| Minimum scheduled output (Psmin) | MW | | 136.0781 | |
| Maximum scheduled output (Psmax) | MW | | 172.5355 | |
| Abs. Minimum Supplier Control Error(\|SCE\|min) | MW | | 0.0003 | |
| Abs. Maximum Supplier Control Error(\|SCE\|max) | MW | | 2.7751 | |
| | | **Declared** | **Scheduled** | **Actual** |
| Ramp down limit (Rmax) | MW/min | -5 | -5.2680 | -7.5625 |
| Ramp up limit (Rmin) | MW/min | 5 | 5.0428 | 7.7548 |
| Maximum acceleration down (Jmin) | MW/min^2 | -10 | -5.8533 | -8.4028 |
| Maximum acceleration up (Jmax) | MW/min^2 | 10 | 5.6031 | 8.6164 |

### Statistical Results (during test period)

| | | |
|---|---|---|
| Avg. \|SCE\| | MW | 0.6674 |
| StDev(\|SCE\|) | MW | 0.5034 |
| Avg. SCE | MW | -0.0289 |
| StDev(SCE) | MW | 0.8356 |
| Correlation Coefficient between Avg. Ps and Avg. Pa | | 0.9987 |

**Figure 6-9**
**Ancillary Services – Load Following**

**The sheets shown here should be aligned next to each other for comparison.**

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| | | **Data Entry Preprocessing** | | | | |
| **1 min. Period Identifier** | **Number of entries/ 1 min. period** | **Logtime** | **Pa Actual Gen. MW** | **Ps Scheduled Gen. MW** | **SCE=Pa-Ps Supplier Control Error MW** | **\|SCE\| MW** |
| 0 | | 29-Sep-99 12:30:00 | 159.3420258 | 159.3490448 | -0.0070190 | 0.0070190 |
| 0 | | 29-Sep-99 12:30:06 | 159.1241150 | 159.3490448 | -0.2249298 | 0.2249298 |
| 0 | | 29-Sep-99 12:30:12 | 159.1091614 | 159.3490448 | -0.2398834 | 0.2398834 |
| 0 | | 29-Sep-99 12:30:18 | 159.0942078 | 159.3490448 | -0.2548370 | 0.2548370 |
| 0 | | 29-Sep-99 12:30:24 | 159.0792542 | 159.3490448 | -0.2697906 | 0.2697906 |
| 0 | | 29-Sep-99 12:30:30 | 159.3035736 | 159.3490448 | -0.0454712 | 0.0454712 |
| 0 | | 29-Sep-99 12:30:36 | 159.2234650 | 159.3490448 | -0.1255798 | 0.1255798 |
| 0 | | 29-Sep-99 12:30:42 | 159.2779388 | 159.3490448 | -0.0711060 | 0.0711060 |
| 0 | | 29-Sep-99 12:30:48 | 159.4509735 | 159.3490448 | 0.1019287 | 0.1019287 |
| 1 | 10 | 29-Sep-99 12:30:54 | 159.4701996 | 159.3490448 | 0.1211548 | 0.1211548 |
| 0 | | 29-Sep-99 12:31:00 | 159.5855560 | 159.3490448 | 0.2365112 | 0.2365112 |
| 0 | | 29-Sep-99 12:31:06 | 159.3740692 | 159.3490448 | 0.0250244 | 0.0250244 |
| 0 | | 29-Sep-99 12:31:12 | 159.3099823 | 159.3490448 | -0.0390625 | 0.0390625 |
| 0 | | 29-Sep-99 12:31:18 | 159.3612518 | 159.3490448 | 0.0122070 | 0.0122070 |
| 0 | | 29-Sep-99 12:31:24 | 159.5983734 | 159.3490448 | 0.2493286 | 0.2493286 |
| 0 | | 29-Sep-99 12:31:30 | 159.5791473 | 159.3490448 | 0.2301025 | 0.2301025 |
| 0 | | 29-Sep-99 12:31:36 | 159.3997040 | 159.3490448 | 0.0506592 | 0.0506592 |
| 0 | | 29-Sep-99 12:31:42 | 159.2843475 | 159.3490448 | -0.0646973 | 0.0646973 |
| 0 | | 29-Sep-99 12:31:48 | 159.5086517 | 159.3490448 | 0.1596069 | 0.1596069 |
| 1 | 10 | 29-Sep-99 12:31:54 | 159.6368408 | 159.3490448 | 0.2877960 | 0.2877960 |
| 0 | | 29-Sep-99 12:32:00 | 159.6945190 | 159.3490448 | 0.3454742 | 0.3454742 |
| 0 | | 29-Sep-99 12:32:06 | 159.4381561 | 159.3490448 | 0.0891113 | 0.0891113 |
| 0 | | 29-Sep-99 12:32:12 | 159.2587128 | 159.3490448 | -0.0903320 | 0.0903320 |
| 0 | | 29-Sep-99 12:32:18 | 159.3163910 | 159.3490448 | -0.0326538 | 0.0326538 |

**Figure 6-10**
**Data Entry Process**

| Data Evaluation -1 min period | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Average (Pa) MW | Average (Ps) MW | Average (SCE) MW | StDev(SCE) MW | Psmax MW | Psmin MW | \|SCE\|max MW | \|SCE\|min MW | Ps Ramp rate MW/min | Acceleration r MW/min^2 | Pa Ramp rate MW/min | Pa Acceleration rate MW/min^2 |
| 159.247 | 159.349 | -0.102 | 0.146 | 159.349 | 159.349 | 0.270 | 0.007 | 0.000 | 0.000 | 0.142 | 0.158 |
| 159.464 | 159.349 | 0.115 | 0.132 | 159.349 | 159.349 | 0.288 | 0.012 | 0.000 | 0.000 | 0.057 | 0.063 |

**Figure 6-11**
**Data Evaluation**

| Ps Ramp rate & (dt)<br><br>Ramp rate MW/min | Acceleration rate<br><br>Acceleration rate MW/min^2 | Pa Ramp rate & (dt)<br><br>Ramp rate MW/min | Acceleration rate<br><br>Acceleration rate MW/min^2 |
|---|---|---|---|
| 0.000 | 0.000 | -2.179 | 20.296 |
| 0.000 | 0.000 | -0.150 | 0.000 |
| 0.000 | 0.000 | -0.150 | 0.000 |
| 0.000 | 0.000 | -0.150 | 23.927 |
| 0.000 | 0.000 | 2.243 | -30.443 |
| 0.000 | 0.000 | -0.801 | 13.458 |
| 0.000 | 0.000 | 0.545 | 11.856 |
| 0.000 | 0.000 | 1.730 | -15.381 |
| 0.000 | 0.000 | 0.192 | 9.613 |
| 0.000 | 0.000 | 1.154 | -32.684 |
| 0.000 | 0.000 | -2.115 | 14.740 |
| 0.000 | 0.000 | -0.641 | 11.536 |
| 0.000 | 0.000 | 0.513 | 18.585 |
| 0.000 | 0.000 | 2.371 | -25.635 |
| 0.000 | 0.000 | -0.192 | -16.022 |
| 0.000 | 0.000 | -1.794 | 6.409 |
| 0.000 | 0.000 | -1.154 | 33.966 |
| 0.000 | 0.000 | 2.243 | -9.612 |
| 0.000 | 0.000 | 1.282 | -7.051 |
| 0.000 | 0.000 | 0.577 | -31.404 |
| 0.000 | 0.000 | -2.564 | 7.692 |
| 0.000 | 0.000 | -1.794 | 23.712 |
| 0.000 | 0.000 | 0.577 | -16.663 |
| 0.000 | 0.000 | -1.089 | 14.526 |

**Figure 6-12**
**PS vs. PA Ramp Rate & Acceleration Rate**

| Logtime | Set Point MW | Gross Output MW | Aux. Load MW | Net output MW | Frequency Hz | Max load MW | Min Load MW | AGC in Automatic |
|---|---|---|---|---|---|---|---|---|
| | LDC10101 | AI10284 | AI10285 | AO10873 | AI10286 | AO10875 | AO10876 | DO12161 |
| 29-Sep-99 12:30:00 | 159.3490448 | 159.3420258 | 8.391888618 | 150.9629 | 59.87266541 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:06 | 159.3490448 | 159.124115 | 8.396197319 | 150.7187 | 59.87255859 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:12 | 159.3490448 | 159.1091614 | 8.40050602 | 150.7187 | 59.87244415 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:18 | 159.3490448 | 159.0942078 | 8.40481472 | 150.6974 | 59.87232971 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:24 | 159.3490448 | 159.0792542 | 8.409123421 | 150.676 | 59.87221527 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:30 | 159.3490448 | 159.3035736 | 8.413432121 | 150.9018 | 59.87210464 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:36 | 159.3490448 | 159.223465 | 8.417740822 | 150.8225 | 59.8719902 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:42 | 159.3490448 | 159.2779388 | 8.422049522 | 150.8774 | 59.87187576 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:48 | 159.3490448 | 159.4509735 | 8.426357269 | 151.0361 | 59.87176895 | 179.996 | Over Range | on |
| 29-Sep-99 12:30:54 | 159.3490448 | 159.4701996 | 8.430666924 | 151.0422 | 59.87165451 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:00 | 159.3490448 | 159.585556 | 8.43497467 | 151.1521 | 59.87154007 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:06 | 159.3490448 | 159.3740692 | 8.439283371 | 150.9262 | 59.87142944 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:12 | 159.3490448 | 159.3099823 | 8.474074364 | 150.853 | 59.871315 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:18 | 159.3490448 | 159.3612518 | 8.439283371 | 150.9018 | 59.87120056 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:24 | 159.3490448 | 159.5983734 | 8.474074364 | 151.1399 | 59.87108612 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:30 | 159.3490448 | 159.5791473 | 8.508865356 | 151.1032 | 59.87097168 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:36 | 159.3490448 | 159.399704 | 8.48029995 | 150.9201 | 59.87085724 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:42 | 159.3490448 | 159.2843475 | 8.451734543 | 150.8103 | 59.87075043 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:48 | 159.3490448 | 159.5086517 | 8.423168182 | 151.0422 | 59.87063599 | 179.996 | Over Range | on |
| 29-Sep-99 12:31:54 | 159.3490448 | 159.6368408 | 8.394602776 | 151.1826 | 59.87052536 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:00 | 159.3490448 | 159.694519 | 8.366037369 | 151.268 | 59.87041092 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:06 | 159.3490448 | 159.4381561 | 8.366037369 | 151.0239 | 59.87029648 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:12 | 159.3490448 | 159.2587128 | 8.366037369 | 150.8835 | 59.87018204 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:18 | 159.3490448 | 159.316391 | 8.366037369 | 150.9507 | 59.8700676 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:24 | 159.3490448 | 159.2074432 | 8.366037369 | 150.853 | 59.86996078 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:30 | 159.3490448 | 159.2437592 | 8.366037369 | 150.8917 | 59.86984634 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:36 | 159.3490448 | 159.2800903 | 8.366037369 | 150.9303 | 59.8697319 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:42 | 159.3490448 | 159.316391 | 8.366037369 | 150.969 | 59.86962128 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:48 | 159.3490448 | 158.9831238 | 8.366037369 | 150.6272 | 59.86950684 | 179.996 | Over Range | on |
| 29-Sep-99 12:32:54 | 159.3490448 | 159.0728455 | 8.366037369 | 150.7004 | 59.8693924 | 179.996 | Over Range | on |
| 29-Sep-99 12:33:00 | 159.3490448 | 159.2010345 | 8.366037369 | 150.853 | 59.86927795 | 179.996 | Over Range | on |
| 29-Sep-99 12:33:06 | 159.3490448 | 159.1049042 | 8.366037369 | 150.7492 | 59.86916351 | 179.996 | Over Range | on |
| 29-Sep-99 12:33:12 | 159.3490448 | 159.0087585 | 8.366037369 | 150.6455 | 59.86904907 | 179.996 | Over Range | on |

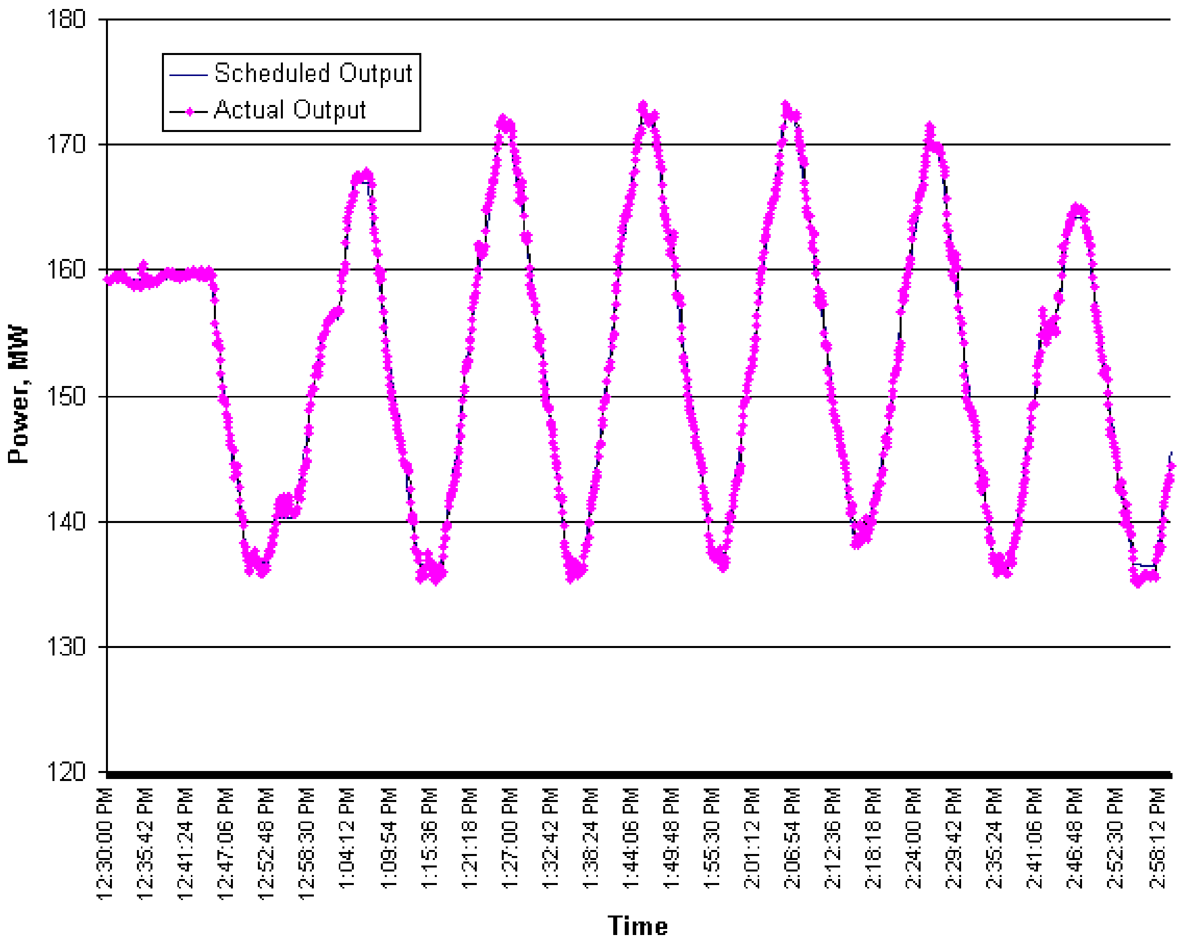



**Figure 6-13**
**Scheduled Output vs. Actual Output**

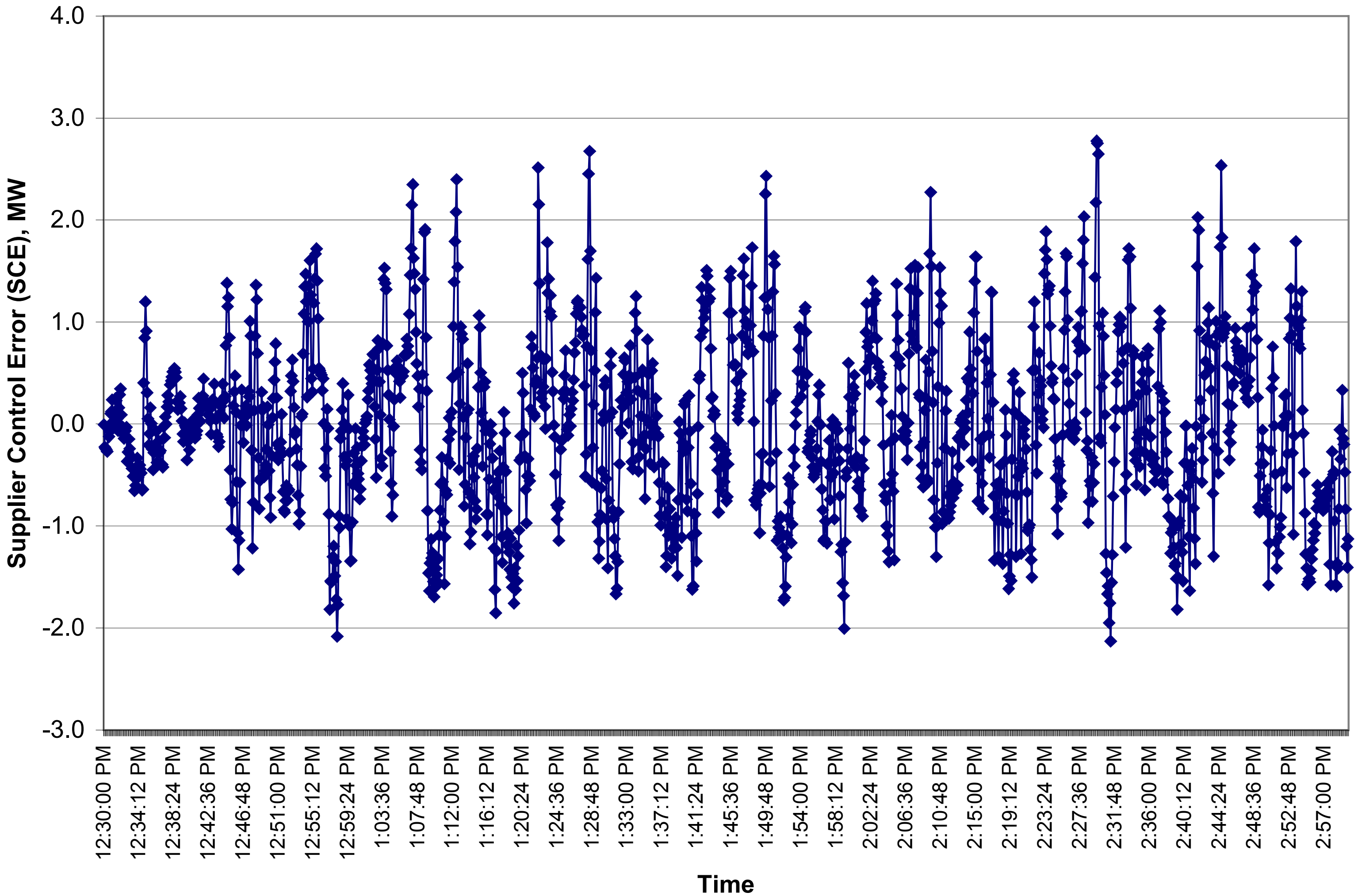



**Figure 6-14**
**Supplier Control Error (SCE)**

## Contingency Reserves – Spinning and Supplemental

All data were recorded in the station computer and retrieved later for analysis in the form of an Excel™ file. The plotting routine of Excel™ was used to plot the target reserves and the actually achieved performance as shown below. The ramp rates of the actual reserve performance were also determined with the help of the plotting routine

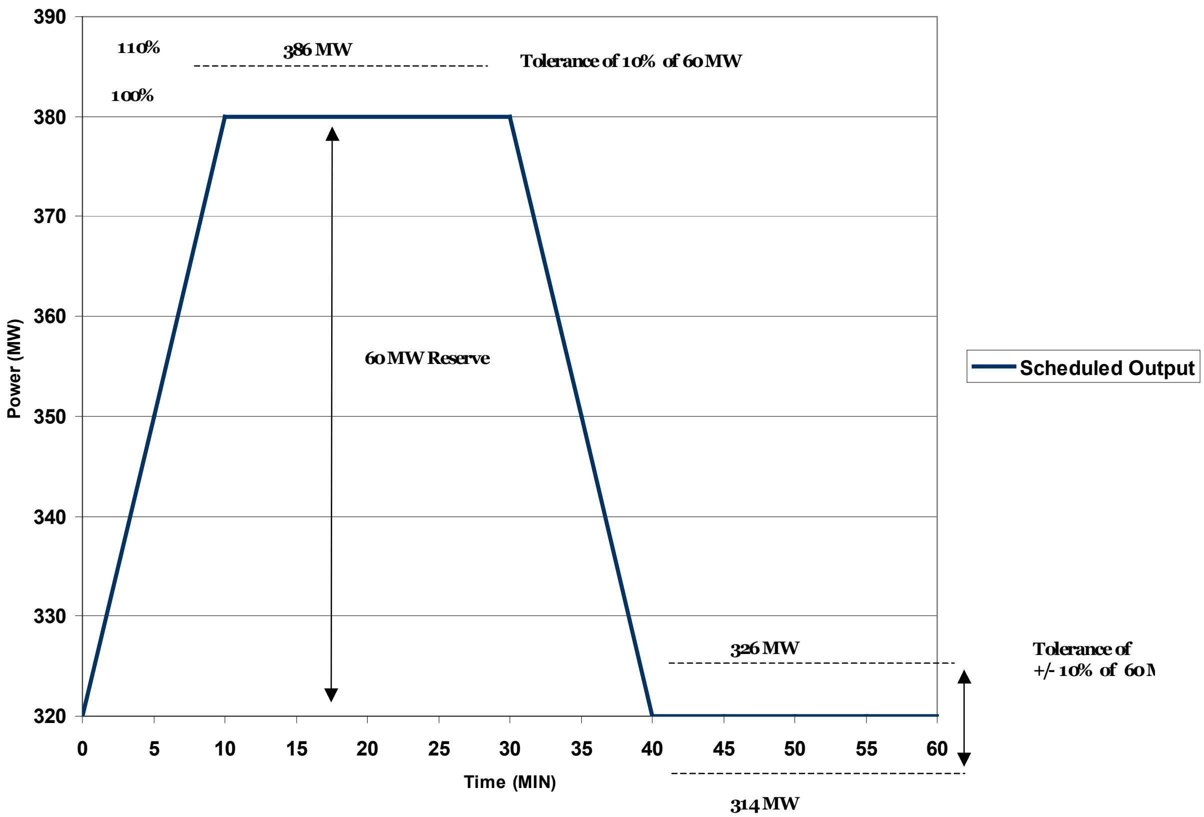



**Figure 6-15**
**Operating Reserve - Spinning & Supplemental "TARGET" with Tolerances per NERC Draft Policy 10.**

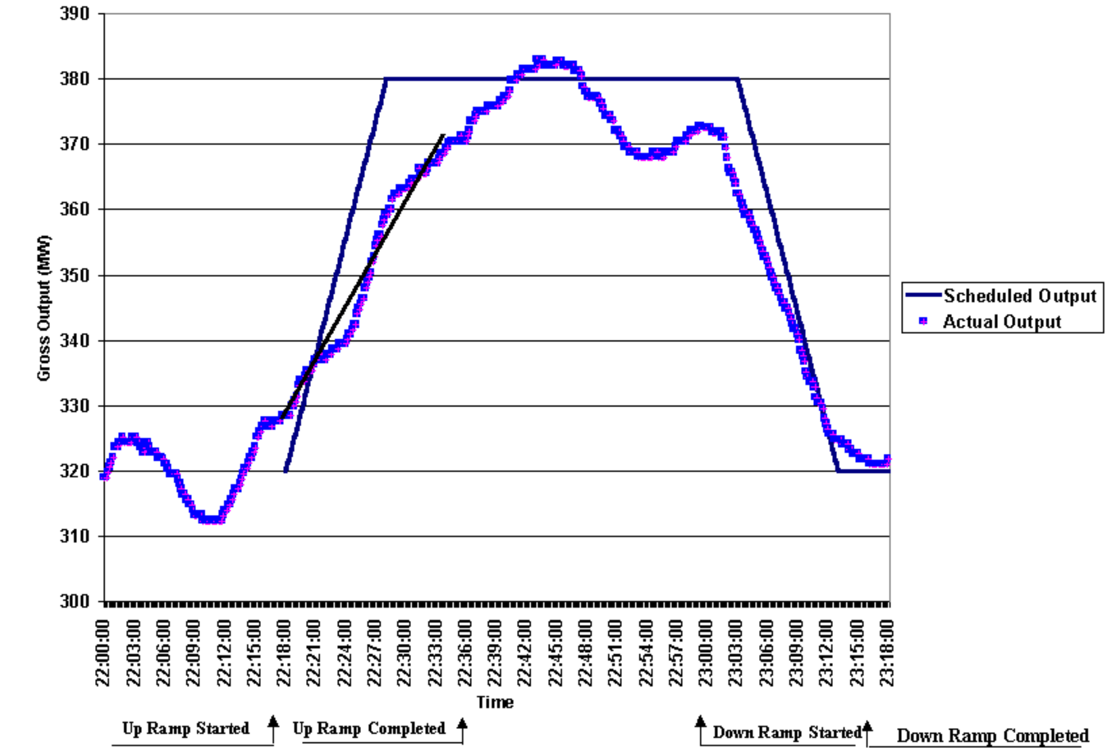



**Figure 6-16**
**First Operating Reserve Test**

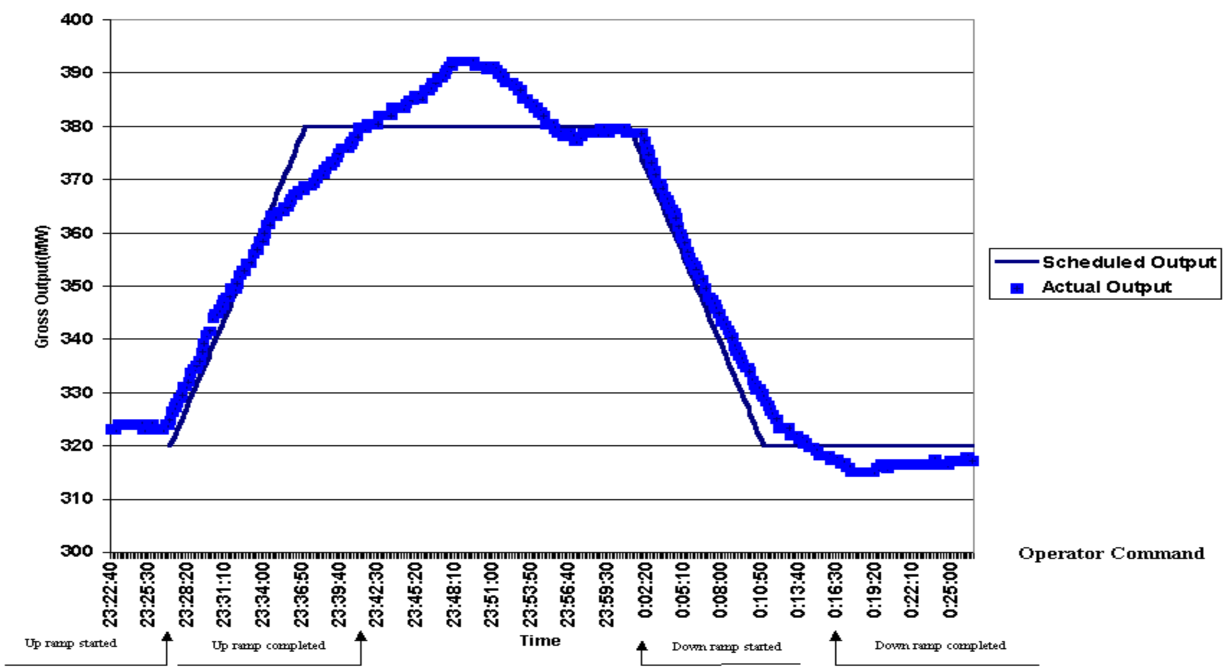



**Figure 6-17**
**Second Operating Reserve Test**

| Time | Boiler Master<br>164117-UK9461 | Gross MW<br>65120JHY800( | Gross MVARS<br>65120JXY800( | Gen Volts Ph R to W<br>165120-EY8006A | Gen Volts Ph W to B<br>165120-EY8006B | Volts Ph B<br>5120-EY800 | 4KV 1A SUPPLY<br>165320-JY8000A |
|---|---|---|---|---|---|---|---|
| 22:00:00 | 15.2837 | 319.039 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:00:10 | 15.2837 | 319.039 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:00:20 | 15.2837 | 319.836 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:00:30 | 15.2837 | 320.633 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:00:40 | 15.2837 | 321.313 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:00:50 | 15.2837 | 322.117 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:00 | 15.2837 | 323.719 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:10 | 15.2837 | 323.719 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:20 | 15.2837 | 323.719 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:30 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:40 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:01:50 | 15.2837 | 325.234 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:00 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:10 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:20 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:30 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:40 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:02:50 | 15.2837 | 325.117 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:00 | 15.2837 | 325.117 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:10 | 15.2837 | 325.117 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:20 | 15.2837 | 324.313 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:30 | 15.2837 | 324.313 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:40 | 15.2837 | 323.633 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:03:50 | 15.2837 | 322.836 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:04:00 | 15.2837 | 322.836 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:04:10 | 15.2837 | 323.633 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |
| 22:04:20 | 15.2837 | 324.438 | 99.4629 | 24.3511 | 24.3213 | 24.3091 | 6.71936 |

| 4KV 1B SUPPLY<br>165320-JY8000B | Net MW<br>5120RHY8( | Gen. Freq<br>165120-CY800( | Line Freq.<br>165130-CY800( | Line Voltage<br>165130-EY800 | Main Stm Pres<br>163611-XI94813 | Main Stm Temp<br>163611-TT-314- | Reheat Temp<br>1163612-TE--20- | FeedWtr Flow<br>164333-FI90608 | Blr Drum LVL<br>16433-XI90635 |
|---|---|---|---|---|---|---|---|---|---|
| 5.10022 | 306.742 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 250.266 | 4.51941 |
| 5.10022 | 306.742 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 250.266 | 4.51941 |
| 5.10022 | 306.742 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 256.836 | 4.51941 |
| 5.10022 | 306.742 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 256.836 | 4.51941 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 243.656 | 4.51941 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 243.656 | 13.4497 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 249.266 | 5.16907 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 255.488 | 5.16907 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 255.488 | 5.16907 |
| 5.10022 | 310.266 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 260.719 | 5.16907 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 260.719 | -3.67792 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 260.719 | -3.67792 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 266.789 | -11.9551 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 266.789 | -11.9551 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -11.9551 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -11.9551 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -3.00769 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -3.00769 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -3.00769 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -3.00769 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -3.00769 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 271.805 | -12.1062 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 277.273 | -12.1062 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 277.273 | -12.1062 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 265.969 | -3.98743 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 265.969 | -3.98743 |
| 5.10022 | 313.734 | 60.0098 | 60.0605 | 241.52 | 13.502 | 527.141 | 514.547 | 265.969 | -14.6116 |

**Figure 6-18**
**Sample of Data from Operating Reserve Test**

## Reactive Power Supply from Generation Sources

The data were captured at one-second intervals and transferred to an Excel™ file whose plotting routine was used to create a graph of the data and evaluate the rate of changes. An example of MVAr response is shown below.

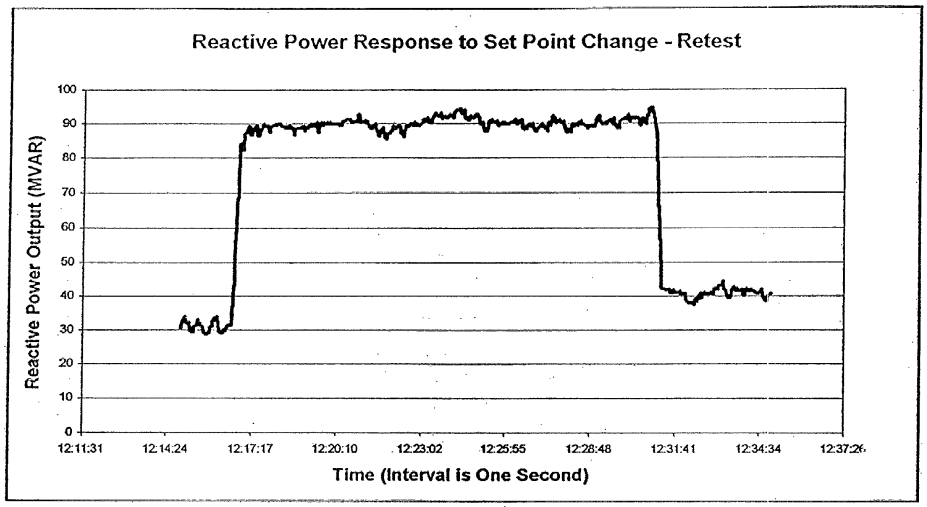



**Figure 6-19**
**Reactive Power Response to Set Point Change - Retest**

# 7
# CURRENT INDUSTRY MEASUREMENT PRACTICES REGARDING ANCILLARY SERVICES/IOS'S

The country is proceeding towards deregulated electricity supply at differing paths and speeds. The NERC draft Policy 10 has not been put into effect but rather been issued as a Reference Document. This suggests that there may be many different practices in the nation regarding IOS's. To gain some insight into these practices, we reviewed the practices of five regional ISO's (Independent System Operators: CAISO, NYISO, ERCOT, NEPOOL, and PJM) regarding certification and testing, as described in their documents titled Ancillary Services manual, protocol or similar. Below is a summary of findings and a comparison with the IOS's listed by FERC and NERC.

## Number of Ancillary Services

The following Ancillary Services were found listed in the documents studied. Note that many different names are used for what probably are similar or nearly identical services, a fact that complicates comparison.

- Scheduling, System Control & Dispatch Service (a FERC ancillary service)
- Regulation and Frequency Response Service (a FERC ancillary service)
- Regulation (a NERC defined IOS)
- Regulation Service – Down
- Regulation Service – Up
- Load Following (a NERC defined IOS)
- Energy Imbalance Service (a FERC ancillary service)
- Balancing Energy Service
- Operating Reserve – Spinning (a FERC ancillary service)
- Contingency Reserve – Spinning (a NERC defined IOS)
- Operating Reserve – Supplemental (a FERC ancillary service)
- Contingency Reserve – Supplemental (a NERC IOS)
- Operating Reserve Service
- Spinning Reserve

- Frequency Response (an on and off NERC IOS)
- Responsive Reserve Service
- Non-Spinning Response Service
- Replacement Service
- Reactive Supply and Voltage Control from Generation Sources (a FERC ancillary service)
- Reactive Power Supply from Generation (a NERC IOS)
- Voltage Support
- System Black Start Capability (a NERC IOS)
- Black Start Service
- Reliability Must-Run Service
- Out-Of-Merit Capacity or Energy Service

Most of this list with over two dozen services is fairly similar to one of the following half dozen, named by FERC and NERC. And they are also those covered by the EPRI sponsored testing described in this report. Thus a review of the requirements for these services should provide an overview of current IOS requirements.

| FERC name | NERC name |
|---|---|
| Regulation and Frequency Response | • Regulation<br>• Frequency Response<br>• Load Following |
| • Operating Reserve – Spinning<br>• Operating Reserve – Supplemental | • Contingency Reserve – Spinning<br>• Contingency Reserve – Supplemental |
| • Reactive Supply and Voltage Control from Generation Sources<br>• Black Start | • Reactive Power Supply from Generation Sources<br>• System Black Start Capability |

A lesson from this comparison is that in all work on measuring and testing Ancillary Services, it is very important to agree on a specific and clear definition before doing any work.

## Testing of Ancillary Services

As discussed earlier in this report, testing can have two purposes. One is to qualify a supplier of an ancillary service according to the ISO's requirements. The other is to demonstrate the capability (often max. and min. values) of a specific piece of generation equipment to supply an ancillary service. This distinction is found in nearly all the documents studied.

All ISO documents studied require qualification testing before the ISO will accept bids for or receive supply of an ancillary service. Some ISO's appear to make it possible for a supplier to conduct its own testing, coordinated with and supervised by the ISO, while at least one (CAISO) insists on conducting all initial certification testing as well as validation of existing certification:

> "The ISO will test resource capabilities for both initial certification and validation of existing certification to ensure the standards for performance and associated operating values are properly represented in the ISO operating system."

The procedure for the latter is very formal and strictly specified. It begins with a detailed written application to the ISO by the supplier to be tested, and is followed by details on responsibilities, information exchange and final approval, including time limits for the various steps. An example of this is the number personnel, functions and responsibilities designated for testing in the CAISO manual:

- Client Relations – Client Representative
- Contracts and Compliance - Compliance Analyst
- OSAT Test Administrator -
- Outage Coordination – Approve and Schedule testing
- Scheduling Coordinators
- Operations Engineering and Maintenance

In the following is a summary of testing required for each ancillary service or group of services.

### *Regulation*

All testing requirements are very similar to those recommended by NERC and consist of 10 min. ramps up or down, each followed by a pause. Station instrumentation and the PI (plant information) system are used for data acquisition. Generally, regulation up and regulation down ramp rates to be approved must be identical, equal to the lower of two test values.

The testing described in this handbook demonstrated the principle of above requirements fully.

### *Load Following*

For the ISO's that recognize this as different from Regulation, the test requirements are similar to NERC's recommendation. Testing is required to determine the ramp rates and the load range within which this service can be offered. Testing together with that for regulation, or interpretation of test data from regulation, is allowed. Quoting from CAISO: *" It is not always necessary to test for each A/S requested for certification as some test results can be used as demonstration for multiple A/S.."*

The testing described in this handbook demonstrated the principle of above requirements fully.

### *Contingency Reserve – Spinning*

The word "spinning" defines this reserve service unambiguously. All ISO's studied require the reserve to be ramped up in 10 min. which is the same as NERC's recommendation. The hold time is not always defined which is also the case for the ramp down time. NERC's recommendation of 15-20 min. hold time followed by a 10 min. down ramp would appear to meet all ISO's requirements. An example of tolerances as defined by ERCOT:

> "All measurements shall confirm the additional delivery of energy due to deployment of responsive service within five percent (5%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety-percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is within five (5%) of expected."

The tolerances on the post event power level are, similarly not mentioned by all ISO's. Again, NERC's recommended values (+/-10% of reserve capacity) would seem to meet all ISO's requirements.

The testing described in this handbook demonstrated the principle of above requirements fully.

### *Contingency Reserve – Supplemental*

The concept of reaching the declared reserve capacity within 30 min. from the call, as found in the NERC recommendations, seem to be included in all ISO requirements. NERC's requirement, that the increase in power output must be achieved in 10 min. is found in some ISO documents. But the tolerance for maintaining the power level (100-110% of declared reserve) and the tolerance for the post event power level appear unique to the NERC recommendations.

The testing described in this handbook demonstrated in principle the above requirements.

### *Reactive Power Supply from Generation Sources*

For the supply of this ancillary service, nearly all ISO documents have prominently the requirement to operate with the AVR (automatic voltage regulator) in service unless instructed otherwise. In CAISO's protocol on Ancillary Services we could find no mention of testing for this service. Another document (NYISO) is only concerned with testing to demonstrate the MVAR capability (lagging and leading) of the units that offer this service. Maximum capability must typically be demonstrated once per year, while capability over the entire load range must be demonstrated less frequently.

The off-line testing of the AVR per "NERC Planning Standards, System Modeling Data Requirements, Generation Equipment", Sections 2B, Measurement 4 and 2B and Measurement 6, recommended by the NERC's IOS Reference document is also found in ERCOT's manual. The "time interval not to exceed five years" is also adopted in this ISO manual.

These requirements were found too demanding for demonstration alone during the testing described in this handbook.

### *System Black Start Capability*

Most ISO's appear to treat this service as a part of their System Restoration Plan. Only one of the ISO ancillary service protocols examined (ERCOT's) covered testing of this service in any detail. The required testing was based on the same principles as the NERC Reference Document, i.e. it consists of three successive tests:

1. Basic starting test, followed by
2. Line energizing test, followed by
3. Load carrying test.

ERCOT's protocol stated: "Providers of Black Start Service shall meet the requirements specified in NERC policy."

The findings on black start testing made during the work described in this handbook will be completely relevant to the requirements described above.

## Failure To Test Or Achieve Required Test Results

All ISO documents examined contain elaborate sections on the financial and operational consequences of failure to demonstrate qualification to supply an ancillary service or maintaining the same. The FERC and NERC documents have no similar provisions.

### *Measurement of Ancillary Services*

The main purpose for performance measurements described in the ISO manuals studied is to provide the basis for the financial settlement for the specific Ancillary Services. This differs slightly from the objective of NERC's recommendations, which are more oriented towards finding a general quality or performance indications for an ancillary service. However, it is only a small step from a certain performance metric to a payments schedule. Thus the principles demonstrated with the measurements covered in this report are totally applicable and can be compared to those in the ISO manuals.

In the following is a summary of the measurements required for each ancillary service or group of services.

### *Regulation*

Several performance measurements are described for this service. Since they are the basis for payments, the measurements mostly must be averaged over considerable time. Practically all measures of performance make use of the Supplier Control Error, SCE=(Pa-Ps), where Pa is actual power and Ps is scheduled power. SCE was the primary quantity developed from the data taken during the EPRI sponsored testing. The SCE values can be evaluated statistically by calculating such quantities as Averages, (for example for one and ten minutes), Standard

Deviation, and Correlation Coefficient, all of which were determined for the data from our testing.

The association of payments with different degrees of performance is a subject for the contract on service delivery, and was not explored by the testing covered by this report.

### *Load Following*

The observations made above for Regulation are valid for Load Following. For both of these services at least one ISO's manual (ERCOT's) recognizes the role of the speed-load governor of the prime mover (turbine), stating that: *"Units providing Regulation must have their governors in service."* In evaluating unit response to remotely generated dispatch signals, it is also required to recognize the load response provided by the governor. The effect of a turbine governor was not included in our testing as all data were taken during constant system frequency.

### *Contingency Reserve – Spinning*

The quality of performance for this service is generally determined by how closely a service provider follows the declared ramp rate and reserve capacity declared when activated. For example, the service is satisfactory when: "Not less than 95% nor more than 120% of the requested reserve is provided within 10 minutes of instruction and maintained until recalled," and: "The reserve requested shall return to within 90% to 110% of its pre-deployment level…". Note the similarity to NERC's recommended requirements and demonstrated during the EPRI sponsored testing. For example, the service is satisfactory when:

1. "Not less than 95% nor more than 120% of the requested reserve is provided within ten (10) minutes of ERCOT's deployment Dispatch Instruction and maintained until recalled or expiration of the service obligation, and:

2. The reserve requested shall return to within 90% to 110% of its pre-deployment scheduled output, subject to the declared capabilities of the provider, within ten (10) minutes following a recall instruction from ERCOT."

Thus the quality of this service can only be measured when activated.

### *Contingency Reserve – Supplemental*

The above listed comments for spinning reserve are equally applicable for this service.

### *Reactive Power Supply from Generation Sources*

The quality requirements we found are simple. The AVR must be in service and operate automatically for a very high percentage of time (e.g. 98% required by ERCOT) as monitored by the ISO, and the response time for a change in set point for voltage or reactive power shall be less than a certain value (e.g. 2 minutes required by ERCOT). We note again the similarity to the NERC recommendations.

The response time for MVAR was part of the testing covered by this report.

### *System Black Start Capability*

Probably due to the nature of this service and the complexity of testing it, there does not appear to be any requirement for routine performance testing of this service. One ISO document emphasizes the obligation to "maintain qualified Black Start Capability… continuously except for periods allowed for routine maintenance."

The evaluation of this service done under EPRI sponsorship did not cover continuous performance evaluation.

## Detailed Specifications of Ancillary Services at CAISO and ERCOT

Sections 8.1 and 8.2, and Appendix C present the requirements of Ancillary testing and qualification at the CAISO. Appendix D presents the same for ERCOT.

## Conclusion

There is a wealth of names for Ancillary Services. Most of them fall in the categories specified by FERC and NERC. All five ISO's whose documents we reviewed have markets in Ancillary Services and specifications for qualification and performance testing. These requirements are very similar to, or strongly influenced by NERC's recommendations.

The EPRI sponsored testing demonstrated the majority of these requirements and the experience gained should be helpful to suppliers wishing to evaluate their units and obtain certification.

## 7.1 CASIO General Test Plan for Ancillary Services

The following represents the current California Independent Systems Operator (CAISO) test approach[1] for Ancillary Services and is intended to initially test the performance of resources of Ancillary Services in order to determine its capabilities.

## Forward

The current California Independent Systems Operator (CAISO) test approach is intended to initially test the performance of a resource wishing to provide Ancillary Services. The objective is to measure the response of these resources to a variety of dispatch instructions to determine the

[1] Source: CAISO General Test Plan for Ancillary Services. For updates, please refer to www.caiso.com.

successful capabilities. The results of such tests are intended to reveal the Ancillary Services the resource is capable of being certified for, the successful quantities tied to such certification, and the general limits of the resource including a units ability to meet the obligations of the power factor range under the CAISO Tariff. The time period typically required to perform such testing will be 1 hour. The CAISO, however, may determine the need to test a unit for the entire 2-hour period (as specified in the ASRP of the CAISO Tariff) for each specific Ancillary Service certification test.

## General Concepts

The CAISO will only procure Ancillary Services from resources larger than 10 MW.

The CAISO requires EMS visibility on all resources from which it will procure Ancillary Services capacity. This is to support the ability of the CAISO to calculate available operating reserves.

The CAISO does not expect any resource to exceed any manufacturers limitations as monitored by the resource. The CAISO will rely on the resource to notify the CAISO should a limitation arise either during the testing or be in immediate risk of occurring.

The objective of the test is to validate unit minimums, maximums, ramp rates, and if the system conditions support such, the VAR capabilities of the unit. The results of such testing may enable the CAISO to certify a unit for more than one Ancillary Service. Should the CAISO certify a unit for multiple services using this "integrated testing" approach, such certification for a service resulting from the integrated approach, absent the specific test, will not relieve the unit from its obligations to provide such service. Further, failure to provide a certified service may result in the application of the appropriate penalties and sanctions as approved by FERC.

If time permits the CAISO intends to verify the various stated ramp rates, but at a minimum will verify the maximum stated ramp rate.

The Scheduling Coordinator for the unit will NOT manage the energy of the unit; rather the CAISO will dispatch the unit for the purposes of the test. This is to minimize the variables that the CAISO generation dispatcher has to manage during the test. Deviations from a unit's market schedule resulting from the test will be settled in the imbalance energy market.

The CAISO will use the observed EMS data for verification of the stated values. The lower of either the stated or tested quantities may be used by the CAISO in determining the data contained in the CAISO Master File.

Instrumentation error is acknowledged and values observed and noted during the test will consider this tolerance should a unit not achieve its stated value.

Following the conclusion of the test, the CAISO will notify the tested resource of the successful quantities the resource is now certified to provide or not certified to provide.

Re-testing of resources will be allowed up to and after the November 1, 1998 deadline, however such resources will have a lower priority on the test schedule than a resource not yet tested. Resources that achieve tested capabilities less than claimed will be certified up to the values observed by the CAISO and included in the next Master File update. The CAISO may consider a resource that failed to complete the testing "non-certified", and thus the resource will be prevented from bidding in the Ancillary Services market.

The CAISO will perform unannounced tests of resources certified for Ancillary Services following the completion of all Ancillary Services testing.

## Prior to Test

The CAISO will confirm the intent and scope of the test with the Scheduling Coordinator for the resource to be tested (scheduled or otherwise) to ensure that the resource is available for testing. The CAISO will consider the Scheduling Coordinator the primary point of contact for the test, unless the Scheduling Coordinator instructs the CAISO to contact the resource directly.

All available information provided by the Scheduling Coordinator for the resources to be tested (Request for Certification forms and possibly other test results) will be collected and available for use by the CAISO personnel directing the test activities.

Forms for recording the test results will be ready and available for use by the CAISO person conducting the test activities. Results will be further documented in-house by the use of print screen "snapshots" of the pertinent facilities being tested during the test. This information is considered proprietary and will to be kept for CAISO records only.

## Generic Test Procedures

### *Regulation*

1. The CAISO will determine whether the regulation testing should be delayed, based on the geographical location of the unit which Area Control Center (ACC) the unit resides in and state of the Area Control Error (ACE), either positive or negative. For example, a significant positive ACE may reduce a unit's ability to move upward should the unit receive a CAISO AGC signal to increase generation output. This may give an inaccurate indication of the true ramp rate ability of the unit in AGC mode.

2. The CAISO will observe the current status of the resource and call the Scheduling Coordinator of the resource to appraise it of the test. A print screen snapshot will be made to document the time and other data pertinent to the resource at the start of the test. CAISO will then dispatch a unit on control to come to a specified MW quantity (either up or down). The dispatched MW quantity change should conform to what the Generator has stated as its maximum regulation ramp rate times 10.

3. The CAISO notes the level of the generator after 10 minutes. The CAISO will also document the time (in minutes) the generator takes to reach the CAISO dispatched schedule if it is less than 10 minutes. After 10 minutes has elapsed, the CAISO notes the output of the Generator, obtains a print screen snapshot, and calculates and notes the maximum ramp rate (in MW/Minute) the unit achieved.

Repeat Steps 2 and 3 for the opposite regulation direction.

### *Spinning Reserve*

1. The CAISO will observe the current status of the generator (the unit should be off AGC control) and call the Scheduling Coordinator for the generator to phone dispatch the unit and initiate the test. A print screen snapshot will be made to document the time and other data pertinent to the generator at the start of the test. The dispatched MW quantity change should conform to what the generator has stated is its maximum spinning ramp rate times 10.

2. The CAISO notes the level of the generator after 10 minutes. CAISO will also document the time (in minutes) the generator takes to reach the CAISO dispatched MW quantity if it is less than 10 minutes. After 10 minutes has elapsed, the CAISO notes the output of the generator, obtains a print screen snapshot, and calculates and notes the maximum ramp rate (in MW/Minute) the unit achieved.

### *Non-Spinning Reserve (may be considered optional dependent on resource)*

3. The CAISO will observe the current status of the resource (if the resource is a unit it may not be synchronized to the system) and call the Scheduling Coordinator of the resource to phone dispatch it and initiate the test. A print screen snapshot will be made to document the time and other data pertinent to the resource at the start of the test. The dispatched schedule change should conform to what the resource has stated is its maximum non-spinning ramp rate times 10.

4. The CAISO notes the level of the resource after 10 minutes. The CAISO will also document the time (in minutes) the generator takes to synchronize (if the resource is a unit) and reach the CAISO dispatched schedule if it is less than 10 minutes. After 10 minutes has elapsed, the CAISO notes the output of the resource, obtains a print screen snapshot, and calculates and notes the maximum ramp rate (in MW/Minute) the unit achieved.

### *Replacement Reserve (may be considered optional dependent on resource)*

5. The CAISO will observe the current status of the resource (if the resource is a unit it may not be synchronized to the system) and call the Scheduling Coordinator for the resource to phone dispatch it and initiate the test. A print screen snapshot will be made to document the time and other data pertinent to the resource at the start of the test. The dispatched MW quantity change should conform to what the resource has stated is its maximum replacement reserve ramp rate times 60.

6. The CAISO notes the level of the resource after 60 minutes. The CAISO will also document the time (in minutes) the generator takes to synchronize (if the resource is a unit) and reach the CAISO dispatched MW quantity if it is less than 60 minutes. After 60 minutes has elapsed, the CAISO notes the MW output of the resource, obtains a print screen snapshot, and calculates and notes the maximum ramp rate (in MW/Minute) the resource achieved.

### Full Output Test

7. Dependent on the test and whether the testing was initiated with a downward ramp, the unit should now be close to full output. If not, the CAISO will direct the generator to go to full load at unity (1.0) or near unity power factor. After the unit appears to have reached full capability (The Scheduling Coordinator may be contacted to confirm the unit is at full output) the CAISO notes the MW and MVAR (if any) output of the generator and obtains a print screen snapshot.

8. Provided system conditions support the test, the CAISO will direct the unit to go to .90 lagging power factor (boosting or providing MVAR's). After an appropriate amount of time (the Scheduling Coordinator may be contacted to confirm they have complied with the dispatch order), the CAISO notes the MVAR output of the generator and obtains a print screen snapshot. If such MVAR output does not correspond to the MVAR output of the generator at .90 lagging power factor, the CAISO will direct the Generator to back an appropriate amount of MW's to support the required MVAR output needed to correspond to a .90 lagging power factor on the Generator. After an appropriate amount of time (the Scheduling Coordinator may be contacted to confirm they have complied with the dispatch order), the CAISO notes the MVAR output of the generator and obtains a print screen snapshot.

9. Provided system conditions support the test, the CAISO will direct the unit to go to .95 leading power factor (bucking or consuming MVAR's). After an appropriate amount of time (the Scheduling Coordinator may be contacted to confirm they have complied with the dispatch order), the CAISO notes the MVAR output of the generator and obtains a print screen snapshot. If such MVAR output does not correspond to the MVAR output of the generator at .95 leading power factor, the CAISO will direct the Generator to back an appropriate amount of MW's to support the required MVAR output needed to correspond to a .95 leading power factor on the generator. After an appropriate amount of time (the Scheduling Coordinator may be contacted to confirm they have complied with the dispatch order), the CAISO notes the MVAR output of the generator and obtains a print screen snapshot.

10. If the generator is unable to reach either such MVAR output (plus or minus) due to either system conditions or terminal voltage on the generator, the CAISO will note such limitations and the MW output of the generator that corresponds to each such limitation.

## Testing Adjustments Required To Accommodate Different Resource Types

### Hydro

No special accommodations are required unless a hydro unit is to be aggregated with other hydro units into a Physical Scheduling Plants (PSP). See PSP for this information.

### *Steam*

The CAISO will attempt to test all stated ramp rates. At the very least, the maximum ramp rate the unit is capable of will be tested. For a unit with low and high range capabilities this will most likely be the high range ramp rate.

### Gas Turbines

Gas Turbines or Combustion Turbines will be allowed 3 attempts at starting. Additional start attempts will likely result in a failure of the unit to provide the bid capacity within the requisite time frame. For Spinning reserve and Non-spinning reserve the time to start and ramp to full load will still be measured against the 10-minute requirement for these services. Should a unit fail to start after 3 attempts, the test will be rescheduled.

Additionally, because of the sensitivity of these units to ambient temperatures, it is the intent of the CAISO to accommodate seasonal ratings for these units. While this functionality does not yet currently exist within the CAISO software, in the interim, the CAISO will incorporate such seasonal ratings by updating the Master File on a seasonal basis. For the purposes of this, winter ratings will be deemed valid starting October 1 through May 31, with summer ratings starting June 1 and ending September 30.

### Physical Scheduling Plants (PSP's)

Units which are to be treated as a Physical Scheduling Plant (PSP's) are comprised of multiple generation facilities. The only type of units allowed to be aggregated in this manner are river system units (i.e. hydro units). In order for the CAISO to verify the units comprising a PSP, the CAISO needs to have sufficient EMS visibility on the individual units, such that the CAISO can monitor and total the unit outputs to verify the stated capabilities.

### Curtailable Demand

In the case of pumps, the CAISO may deem a number of resources wishing to be certified for non-spinning and/or replacement reserves considered "certified" by the demonstration of dropping only one unit in a plant rather than the entire plant. This will only be allowed if the units are identical in nature, as the process of setting up and following the CAISO dispatch for one unit may demonstrate the ability of the operator to perform the task for the others.

## Notifications, Use of Test Results and Failure to Perform

The CAISO will release the results of the tests in a timely manner following the test. This will be accomplished via email notification with a summary of the observed results.

The observed values are what the CAISO will support for inclusion in the Master File.

Certified values are the tested quantities the resource has stated it is capable of reliably and repeatedly providing to the CAISO should the CAISO dispatch the resource. Such tested values will be used as a benchmark by which future performance will be measured. The CAISO is attempting, through this testing process, to observe such capabilities, however, the testing was not intended to fully encompass all services a resource wishes to be certified for. It is the resource's Scheduling Coordinator (SC) that assumes the responsibility for accurately representing the resource's capabilities. The result of such being that if the CAISO dispatches a certified unit for a service, and the resource fails to provide the service, the resource and the SC are both subject to the CAISO tariff penalties and sanctions as approved by FERC. The only impact on the resource may be that it may have its certification for Ancillary Services suspended. The real burden of responsibility falls upon the SC to properly bid the capabilities of the unit.

An example of what the CAISO would prefer to avoid would be that if a steam unit bid spinning reserve into the market at its high range ramp rate, simultaneous with a generator set-point in the low range of the unit. If the CAISO were to call on such capability, this would constitute a failure to provide a certified service. This would subject the unit to a review of its certification, with potential suspension of certification, and the SC to the application of the penalties and sanctions as approved by FERC.

### Future Testing

The CAISO will, on a periodic basis, undertake unannounced testing. This is intended to verify certified capabilities, as well as performing quality spot-checking of the Ancillary Services the CAISO procures. The CAISO also intends to ultimately verify, inspect or test ALL resources, not merely those being certified for Ancillary Services, to substantiate the resource's capabilities as reflected in the Master File.

### Other Items of Note

Distribution Loss Factors (DLF's) are accounted for in the CAISO metering, and are similar to GMM's, which account for transmission losses. These factors are used for settling metered energy quantities and are not to be included in a generator's capacity for purposes of this testing.

## 7.2 CASIO Ancillary Services Testing and Request Form

CALIFORNIA ISO

### Ancillary Services Testing and Request Form

Test Type: ☐ Certification ☐ Retest ☐ RIG ☐ Compliance ☐ Import A/S ☐ RMR
☐ P-max ☐ P-min ☐ Regulation ☐ UP ☐ Down
☐ Spinning Reserve ☐ Non-Spinning Reserve ☐ Replacement Reserve

Requestor: ☐ Generator ☐ Scheduling Coordinator ☐ Operator ☐ Provider of Curtailable Demand ☐ ISO

Organization: ______

Principal Contact Name: ______ Phone: ______

Designated Scheduling Coordinator: ______ Phone: ______

Resource:

Common Name: ______ Resource ID ______

Fuel Type ______ Controlling bus voltage @ ______ kV

Resource Requirements:

Included in PGA Schedule 1 ☐ Yes Covered by signed MSA ME ☐ Yes

ISO EMS MW visibility ☐ Yes ISO Certified Metering Installed ☐ Yes

AGC Requirements:

Dynamic Signals Provided to ISO EMS

High limit (MW) ☐ Low limit (MW) ☐ Monitor AGC status ☐

Rate limit (MW/min) ☐ Availability status ☐

Spin Data and Requirements:

Governor deadband ______ + Hz ______ - Hz Droop Characteristic ______ %

Unit has block loading capability ☐ yes RTU or SCADA MW and MVAR data to ISO ☐ yes

Curtailable Demand Requirements:

Minimum is greater than 1.0 MW ☐ yes Can be interrupted for at least 2.0 hrs. ☐ yes

Load monitored by ☐ ISO ☐ Scheduling Coordinator ☐ Other (specify) ______

Communication Requirements:

ISO approved digital communication between generator control interface and ISO EMS ☐ yes

ISO approved redundant digital communication between generator control interface and ISO EMS ☐ yes

Pre-Test Preparation Requirements:

EMS Display ID: ______ EMS Identification Text: ______

EMS Measurand Information Point: ______

EMS Development Test ☐ yes EMS Production Test ☐ yes

Test Schedule Date: ______ Approved by Outage Coordination: ______

| Test Table | Start Time | Start MW | End Time | End MW | MW Change | MW Range (completed by requestor) | Stated Value (completed by requestor) | Tested Value |
|---|---|---|---|---|---|---|---|---|
| P-max 1.0 pf | | | | | | | | |
| .95 lead pf | | | | | | | | |
| .90 lag pf | | | | | | | | |
| P-min | | | | | | | | |
| Reg up | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| Reg dn | | | | | | | | |
| | | | | | | | | |
| Spin | | | | | | | | |
| | | | | | | | | |
| NSP | | | | | | | | |
| | | | | | | | | |
| Replace | | | | | | | | |
| | | | | | | | | |
| Demand | | | | | | | | |

Tested by: ______ Contact: ______ Date: ______

# 8
# VOLTAGE CONTROL AND REACTIVE POWER MANAGEMENT

Power system needs both the dynamic active and reactive power controls for the best and most economical performance. Rapid reactive power control from the generators is much more achievable than rapid active power control which is much more important for system stability[1]. If high-speed active power control capability in the generators is available, then it is conceivable that it would have found its way to the top of the list of ancillary services. Controllability of reactive power in generators is fast since it involves electronic control of excitation current and does not need mechanical power control. The control at reactive power at the generators may not an optimum location, and it would be more effective at the load, where it is being consumed. Also, from the point of view of maximizing energy production at lowest cost, it makes much more sense to operate generator without significant demands of high-speed controls, and hence focus the role of generators on the production of real power, rather reactive power. You cannot have a generator supplying reactive power ancillary services when it is supplying maximum active power.

For some needs, transmission can do what generation cannot. For example, turbine-generators cannot do much in the way of controlling transient instability[2], beyond its response due to inertia. Here the FACTS[3] technology can be very useful. Dynamic reactive power is often more effective elsewhere than at the generation sites. Sources of reactive power have to be provided where needed. Transmission of reactive power from one area to another penalizes others in terms of cost of delivering energy. Also, the best method to rapidly kill oscillations and absorb sudden changes in load, is to correct voltage profile at the load buses with rapid reactive power control and let the generators find balance with the load at their slow speed.

The Federal Energy Regulatory Commission (FERC) recognized the importance of voltage control by including it as an ancillary service in Order 888, Reactive Supply and Voltage Control from Generation Sources. FERC differentiated generation-based activities from transmission-system-based activities, with the latter to be addressed under the basic transmission tariff.

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[1] For the first few seconds or even tens of seconds after a system disturbance, we do not have any active power control from the generators.

[2] Generally, the generator response is too slow to save a system in case of dynamic instability system, hence the need for measures such as: increased transmission margins , generation dropping, load shedding and islanding need to be implemented today to insure system stability.

[3] FACTS Technology Flexible AC Transmission System (FACTS) is defined by IEEE as: "Alternating current transmission systems incorporating power electronic-based and other static Controllers to enhance controllability and increase power transfer capability."

## Short Note on FACTS Devices

FACTS Controllers can dynamically control line impedance, line voltage, active power flow and reactive power flow. They can absorb or supply reactive power and when storage becomes economically viable storage they can supply and absorb active power as well. All this can be done at high speed. FACTS technology can provide services related to stability, voltage control and network loading control. It can also enhance available transmission capacity for given transmission facilities or upgraded and new transmission facilities. Potentially for the future, if economically viable short-time storage becomes available, it can also serve the functions of rapid frequency control and maybe even system restarts, but this is somewhat down the road and we must rely on generation to cover for the frequency control and system restarts. The FACTS technology can supplement generation in the role of providing voltage control ancillary service, if the rules for procurement of these services enable such a scenario.

Section A describes some of the specifics of voltage control from generators (the present Ancillary Service). Section B describes the aspects of voltage control on the transmission systems.

# 9
# THE CONTRIBUTION OF ENERGY AND ANCILLARY SERVICES TO NET INCOME OF GENERATING UNITS IN U.S. POWER SYSTEM[1]

In a restructured electricity market, power plants earn revenue from both energy and ancillary service (A/S) markets, and profits are maximized through an optimal allocation of scarce capacity between energy and A/S sales. New participants considering entering competitive operations have little information to help them understand how much additional revenue Ancillary Services can contribute to their income or how they might consider operating their units.

An analysis of energy and A/S contribution to profits has been performed on representative base-load, mid-merit, and peaker plants in four restructured U.S. power markets: New York, New England, Electric Reliability Council of Texas (ERCOT), and California. Information on the respective contributions of energy and A/S markets to a plant's profits is crucial to short-term operational objectives as well as to long-term investment plans.

The methodology is based on an ex-post assessment of opportunity cost of a generator seeking to allocate two blocks of capacity. Using historical price data, an analysis was performed to determine the best use of a unit in the energy and Ancillary Services markets to maximize income. The purpose of this approach is to illustrate that the opportunity to participate in multiple markets offers significant returns to generators if their units are optimally operated in each market. Having done that, a supplier will seek to determine the optimal bidding strategies and unit operations in the future, when prices are not known in advance. A proper analysis of the future prices and unit operations can be performed using UPLAN, an LCG proprietary model, which can find rational expectations Nash equilibria for multiple players, commodities, and markets across space and time.

A/S is a significant source of income for base-load and mid-merit plants, assuming they are correctly bid into these markets (see Summary Table 9-1 below). Base-load units capable of regulation or spin may earn up to 40% of their income from A/S. Mid-merit units capable of regulation or spin may earn up to three-fourths of their income from A/S. Peaker units capable of ten-minute non-spinning reserve may earn up to 48% of their income from A/S.

[1] This chapter was prepared by LCG Consulting, Los Altos, California. The principal investigators are: Richard Alpert (project lead), Dr. Christopher Lund, Nicholas Brown, and Dr. Manny Macatangay. The authors benefited from discussions with Dr. Rajat Deb and Dr. Amir Mousavi.

**Table 9-1**
**Summary of Contributions to Income from Energy and A/S for Different Plant Types**

| Plants | | Markets | NYISO | NEISO | ERCOT | CA |
|---|---|---|---|---|---|---|
| Base-load | With Regulation | Energy | 63% | 95% | 88% | 28% |
| | | A/S | 37% | 5% | 12% | 72% |
| | No Regulation | Energy | 76% | 99% | 91% | 90% |
| | | A/S | 24% | 1% | 9% | 10% |
| Mid-merit | With Regulation | Energy | 28% | 61% | 50% | 14% |
| | | A/S | 72% | 39% | 50% | 86% |
| | No Regulation | Energy | 47% | 75% | 50% | 73% |
| | | A/S | 53% | 25% | 50% | 27% |
| Peaker (No Regulation) | | Energy | 52% | 79% | 53% | 53% |
| | | A/S | 48% | 21% | 47% | 47% |

## Aim, Rationale and Scope of the Study

The aim of the study is to calculate the contribution of energy and Ancillary Services (A/S) to the profits of representative base-load, mid-merit, and peaker plants in the U.S. power system. In a restructured electricity industry, markets govern the operation and expansion of electricity generation, and power plants make money from markets for energy and A/S. Maximum profits are achieved not only through correctly bidding a plant's opportunity cost[2] but also through the optimal allocation of its output between energy and the various A/S, such as regulation up, regulation down, spin, non-spin, and replacement. As a consequence, the shares of energy and A/S to total profits of a power plant are key pieces of information guiding a plant's operations and indicating the expected profitability of potential generator entry.

The restructured markets under study are four of the five U.S. power systems under the control of an independent system operator (ISO): New York, New England, Electric Reliability Council of Texas (ERCOT), and California (The fifth one, excluded in this study, is the Mid-Atlantic system comprising the Pennsylvania-New Jersey-Maryland area, or PJM, which is primarily cost based with operating reserves reimbursed as compensation for being provided. Thus, the ramifications of this study would apply differently to entrants in that market.) Except for ERCOT, the focus is on a historical retrospective for the year 2000, to see how typical units

[2] Defined as the greater of marginal production cost and the expected prices in the different markets to which a plant could sell. See Rajat K. Deb, Pushkar Wagle, & Rafael Emmanuel A. Macatangay, *Generation and Transmission Investments in Restructured Electricity Markets*, Environmental Monitor (forthcoming). Also see Rajat K. Deb, *Analyzing Multiple-Product Power Markets: Simulation of Energy and Ancillary Services Prices and System Adequacy*, EPRI, Palo Alto, and LCG Consulting, Los Altos (2000).

might have operated, given the price outcomes. ERCOT did not have ancillary service prices available until beginning in August 2001, and as such, ERCOT has been studied for September and October 2001.

## Energy and Ancillary Service Markets in the Restructured U.S. Power Industry

A restructured electricity market is usually composed of forward and spot markets. The forward market may have bilateral contracts, futures, options, day-ahead and hour-ahead energy markets, and in some areas, A/S markets. In the spot (or real-time) market, only energy is traded. A large number of factors affect the behavior of these markets, such as the institutional arrangements of the market, physical features of the grid, environmental restrictions, psychology and expectations, weather, hydrological conditions, load growth, entry, and volatility.[3] Volatility exposes market players to locational basis risk, arising from price differences across geographic regions, as well as to forward/spot basis risk, arising from the difference between the future price and cash value of the underlying commodity. The most fundamental instruments for hedging risk are bilateral contracts and futures. A related strategy is the purchase of options on futures.[4]

Reliability services, such as short- and long-term reserves, have been unbundled into several A/S. Customers of the transmission grid purchase A/S from the market in order to secure the amount and quality of their electricity requirements. Energy and A/S are generally organized into several markets: forward, regulation, operating reserve, replacement reserve, capacity, and balancing. In forward markets, a buyer and seller of energy agree on delivery at a pre-determined price and future time. In the regulation market, a plant under automatic generation control (AGC) is used to maintain balance between load and resources. In the reserve market, energy is delivered within a specified time period, usually ten minutes. Spinning reserves are on-line and synchronized and provide simultaneous frequency and/or voltage support. Non-spinning reserves are not necessarily in operation but must be capable of synchronization and ramping within a specified time period. In the market for replacement reserves, units previously dispatched as operating reserves may be backed down and form part of replacement, a "slow" reserve product. In the capacity market, a particular portion of operable capacity is made available to provide energy and/or operating reserves. Finally, in the balancing market, a real-time balance between load and resources, and the satisfaction of NERC operating criteria, are achieved.

Revenues from energy and A/S are important components of a generator's financial stability. In maximizing its profits, a power plant has to bid its opportunity cost, and to achieve an optimal allocation of its capacity between energy and A/S. Energy and A/S market clearing prices (MCPs) interact in a variety of ways. For example, payments for A/S reserve capacity are similar to insurance revenues: the seller of A/S is insuring energy users against contingencies in the energy market. Under some circumstances, however, A/S provides little insurance, and the long-run price of A/S reserve capacity is close to zero. One reason for the "limited insurance" is that a dispatched generator receives a high price in the event the contingencies requiring dispatch do

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[3] See Rajat K. Deb, Pushkar Wagle, & Rafael Emmanuel A. Macatangay, *Supra* Note 1.

[4] Details are in Rajat K. Deb, *Supra* Note 1.

indeed occur. In such a situation, the probabilistic revenues from real-time dispatch replace the revenues from capacity sales, and the generator chooses to participate in the energy market, which is the most profitable market it faces.

There are other commercial concerns regarding energy and A/S markets. In view of the small operating costs of providing A/S, the relevant cost of A/S is the revenue foregone from energy sales. Reserves located near loads may earn a higher capacity price than those isolated by transmission constraints. For a hydroelectric plant, A/S may be provided in off-peak hours, but the reservation price for dispatch is the expected energy price in peak hours, in the event generation off-peak reduces available generation at the peak. For a thermal plant, the potential earnings from energy and A/S affect the decision to start the unit. In essence, therefore, energy and A/S are typically substitutes, and the expected earnings from A/S are significant. Indeed both energy and A/S revenues contribute to the recovery of investment. The relative shares of energy and A/S revenues depend on institutional arrangements, payments mechanisms, and volatility.[5]

## Four U.S. Control Areas

The four ISOs under study are New York (NYISO), New England (NEISO), California (CAISO), and ERCOT. NEISO and NYISO exercise tight control over location dispatch but have markets for A/S. CAISO has an auction for real-time energy and, prior to the closure of the Power Exchange (PX), used to have one for A/S. ERCOT, which began to report A/S prices only in September 2001, is the residual manager of bilateral contracts arranged among market players. A discussion of each of the four ISOs, including the representative plants employed in the revenue contribution analysis involving energy and A/S follows in the next four sub-sections.

### *New York*

The NYISO operates day-ahead, hour-ahead, and real-time energy markets as well as multiple ancillary service markets. Energy market participants may submit bids on a day-ahead and/or hour-ahead basis for generation, load, and bilateral transactions. During day-ahead processing, the NYISO uses day-ahead capacity bids and seven-day load forecasts to designate which generators will be available for dispatch the following day. The ISO also establishes locational-based marginal energy prices (LBMPs) and schedules a variety of Ancillary Services. Ancillary services in the NY control area include, but are not limited to, regulation (REG), ten minute spinning reserve (TMSR), ten-minute non-synchronized reserve (TMNSR), and 30-minute reserve (30M RES). Ancillary services for the 11 zones within the NY control area are purchased through the NYISO (*i.e.* single price for each service) and are used to maintain reliable operation of the NY power system. Following the close of the day-ahead market, the ISO uses hour-ahead capacity bids to meet changing loads and to respond to generation and transmission outages. This new set of LBMPs is applied to transactions in the real-time energy market. The NYISO guarantees coverage of start-up and minimum-run costs for dispatched generators; generators that provide operating reserves and whose energy bids are below the relevant LBMP receive an opportunity cost payment.

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[5] Ibid.

Analyses were carried out on three plants located in the Hudson Valley load zone: a 234 MW coal-fired base-load unit, a 610 MW natural gas-fired mid-merit unit (*i.e.* steam turbine), and a 40 MW natural gas-fired peaking unit (*i.e.* combustion turbine). The units became operational in 1967, 1972, and 1993, respectively.

### New England

NEISO uses locational pricing for energy. Its A/S markets are AGC, ten-minute spinning reserve, ten-minute non-spinning reserve, and thirty-minute operating reserve. A participant sells into the energy market the amount unused by its native load. In order to mitigate market power, a player has to bid any capacity that is not self-scheduled for meeting native load or sold through a bilateral transaction. Every five minutes, NEISO calculates an energy MCP equal to the cheapest MW supply increment that was not called for dispatch. The price to sellers is the weighted average, over an hour, of the five-minute MCPs.

An analysis of energy and A/S market net income was performed on three thermal plants in Massachusetts: a 255 MW coal-fired base-load unit, a 380 MW gas-fired mid-merit unit (i.e. steam turbine), and a 270 MW gas-fired peaking plant (i.e. combustion turbine).

### California

The two key institutions in California's wholesale power market are the Power Exchange (PX) and the ISO. The PX, which closed on 31st January 2001, administers the forward energy markets. It was a scheduling coordinator (SC), one of the many certified by the ISO. It used to be responsible for sending preferred schedules and adjustment bids to the ISO that, in turn, calculates zonal market clearing prices (MCPs) and uses them in congestion management and settlements. The ISO is responsible for overall grid security. It manages Ancillary Services through market operations as well as through contracts, such as reliability must-run (RMR) contracts. It also oversees the real-time imbalance energy market as well as transmission congestion protocols involving the minimization of redispatch costs calculated from "inc" and "dec" generator bids. The CAISO territory is divided in three zones: north, south, and central, corresponding to three hourly zonal MCPs for energy and A/S.

The three plants selected for this control area are all natural gas-fired. They include a 739 MW base-load unit, a 338 MW mid-merit unit, and a 53 MW peaking unit with operational dates of 1968, 1963, and 1986, respectively. The base-load and peaking plants are located in northern CA and the mid-merit plant is located in central CA.

### ERCOT

ERCOT has relied on bilateral contracts that must be backed up by adequate operating reserves (*i.e.* firm) and supported by transmission capacity (*i.e.* feasible). However, ERCOT began reporting A/S prices beginning in August 2001. Previously, the task of energy dispatch was left to control area operators. ERCOT made sure that submitted schedules are feasible and have sufficient operating reserves meeting ERCOT reliability standards. The energy and A/S markets to be controlled by ERCOT are now under development and are expected to be fully in place by

January 2002. The review of how suppliers might have operated in the markets was done for September and October 2001 based on recorded prices.

Three units were selected for this analysis: a 555 MW coal-fired base-load plant, a 390 MW natural gas-fired mid-merit plant, and an 80 MW natural gas-fired CT peaking plant.

## Methodology

The methodology is based on an assessment of opportunity cost and rational expectations decision-making in restructured power markets in the U.S. We used publicly available ISO energy and A/S market MCPs for the year 2000 to conduct an ex-post analysis of the contributions of energy and A/S net income to total net income. Using hourly MCPs in conjunction with unit specific data such as heat rate, fuel costs, and variable O&M costs, we can estimate the optimum allocation of capacity between energy and A/S markets.

For the base-load and mid-merit units, we consider two scenarios. In the first scenario, the units can participate in the energy market and either the regulation or ten minute spinning reserve A/S markets. In the second, units can participate in the energy and ten minute spinning reserve A/S markets (i.e. no AGC equipment installed). For the peaking unit, we consider a single scenario in which the unit can participate in the energy market and either the ten-minute non-synchronized reserve or thirty-minute reserve A/S markets. The net income from each market is calculated using the set of decision rules outlined below.

A generator has to allocate two blocks of capacity, Block 1 with marginal cost $MC_{min}$, and Block 2, $MC_{max}$, to two markets, energy and A/S, whose market clearing prices $MCP_e$ and $MCP_{A/S}$ are known. $MCP_e$ is typically greater than $MCP_{A/S}$. There are two general cases, and two sub-cases under each.

- If $MC_{\min} < MCP_e$ (see Figure 9-1), then run Block 1 in the energy market, and assess:

- If $(MCP_e - MC_{\max}) > (MCP_{A/S})$, then run Block 2 in the energy market. This condition simplifies to $(MCP_e - MCP_{A/S}) > (MC_{\max})$. Running both blocks in the energy market brings the most profit.

- If $(MCP_e - MC_{\max}) < (MCP_{A/S})$, then run Block 2 in the A/S market. This condition simplifies to $(MCP_e - MCP_{A/S}) < (MC_{\max})$. Running Block 2 in the A/S market brings more profit than running it in the energy market.

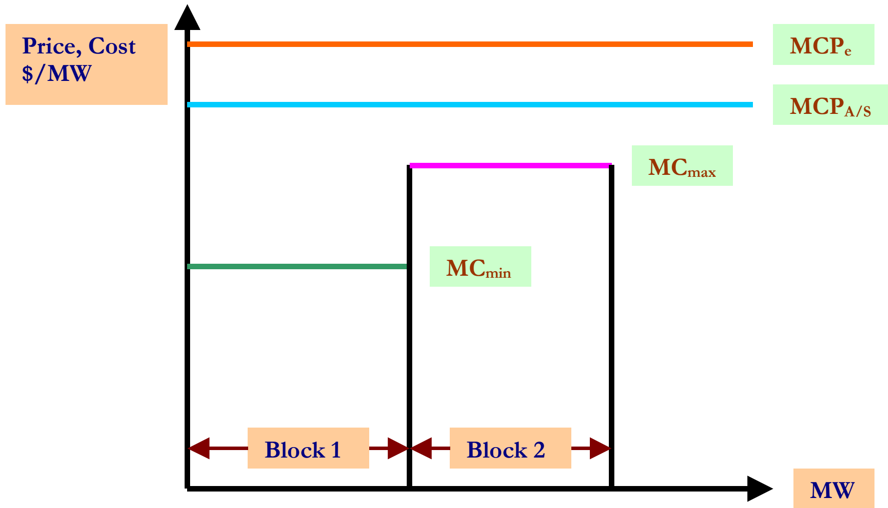


**Figure 9-1**
**MC of Block 1 is Below Energy MCP**

⇒ If, however, $MC_{\min} > MCP_e$ (see Figure 9-2), then assess: If $(MCP_{A/S})*(Block2) > (MC_{\min} - MCP_e)*(Block1)$, then run Block 1 in the energy market and Block 2 in the A/S market. The loss in running Block 1 in the energy market is more than offset by the gain in running Block 2 in the A/S market.

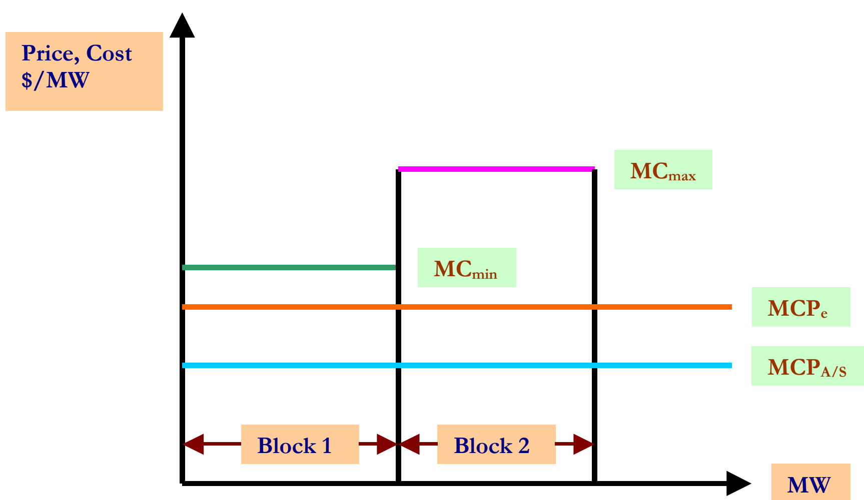


**Figure 9-2**
**MC of Block 1 is Above Energy MCP**

The methodology is illustrative and inevitably has a number of limitations. First, the plant's decision to allocate capacity is based solely on a static evaluation of known MCPs. A complete assessment, however, involves a simulation of the dynamic and iterative processes involved in multi-commodity, multi-player games. A bid in one market reflects the opportunity cost of that in another. In the presence of many players, the solution to the game is found through an iteration of best-response functions for each player across all markets. All arbitrage opportunities are exhausted. UPLAN, our proprietary engineering economy model of the U.S. power system, is capable of modeling the multi-commodity, multi-player games played in power markets.

The second limitation of the methodology is that fundamental drivers of the market are not represented. A proper analysis, however, has to account for the fundamental factors driving market outcomes. In UPLAN, each player is modeled to understand the key factors underlying the different spatial and temporal markets in restructured power markets (see Figure 9- 3). The resulting Nash equilibrium is therefore generated through rational expectations. The third, but by no means final, limitation is that transmission constraints are ignored. However, a rigorous representation of the grid is needed for a proper evaluation of imports, a prime determinant of the intensity of competition in, and thus the profitability of, a geographic market.

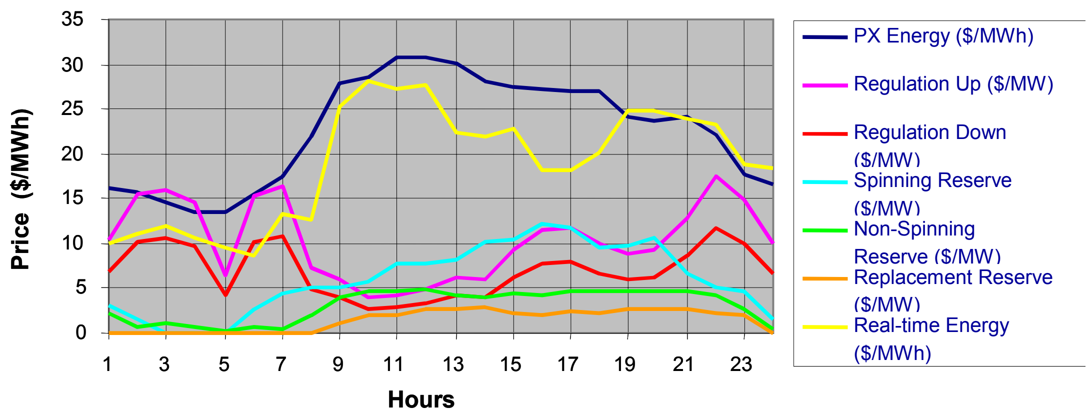


**Figure 9-3**
**Energy and A/S MCPs Generated by a UPLAN Simulation.**

In short, in a restructured electricity industry, the market realities are exceedingly complex, and price is determined by a confluence of a large number of different events and factors.[6] Supply and demand are just one set of factors. All possible market design loopholes and legal inconsistencies are exploited for profit. The status-quo pattern of transmission constraints is usually beneficial to some generation and transmission owners but detrimental to others. Any proposed alteration of the network implies a redistribution of rents, a change in bidding strategies, and, depending on the location of the players, a realignment of alliances. The potential for earning capacity payments in the ancillary service markets, as in California, is a powerful incentive to withdraw capacity from the energy market, in which payments are purely on energy. Expectations of drought and unfavorable changes in weather patterns increase the scarcity value of water and worsen any strategic behavior exercised by the hydro unit. Thus, many interacting

[6] See Rajat K. Deb, Pushkar Wagle, and Rafael Emmanuel A. Macatangay, *Supra* Note 1.

factors are at work, and any market analysis of generator operation and investment quickly becomes intractable.

## Results

### *NYISO*

Table 9-2 shows the contributions of energy and A/S net income to total monthly unit net income for the year 2000. In some instances, units loose money in the energy market, and this is shown as negative values in Table 9-2. For the base-load plant capable of providing regulation (REG) or ten minute spinning reserve (TMSR), A/S net income is significantly larger than energy net income from January through April (see Table 9-2 and Figure 9-4). Beginning in May, this pattern reverses, with energy income becoming an increasingly dominant fraction of total net income. A similar pattern can be observed for the base-load plant capable of TMSR only (see Figure 9-5). Not surprisingly, energy income is an even larger fraction of total net income when the base-load unit is unable to participate in the regulation market. The mid-merit plant shows a somewhat different monthly income pattern. For the mid-merit plant capable of providing REG or TMSR, A/S income is much larger than energy income from January through May, but shows no consistent pattern thereafter (see Figure 9- 6). As is the case with the base-load unit, when the mid-merit plant is unable to provide REG, a larger fraction of total net income comes from the energy market (see Figure 9-7). For the peaking unit capable of providing either ten minute non-synchronized (TMNSR) or 30 minute (30M RES) reserves, the pattern is somewhat similar to what is observed for the base-load unit, with A/S income dominating energy income early in the year, and energy income dominating A/S income from April through December (see Figure 9-8). In relative and absolute terms, A/S income for all units tends to be greatest from January through March, reflecting the seasonal peak in A/S market prices (see Figure 9-9).

Examining the contributions of energy and A/S income to annual net income is also quite interesting. Energy market net income accounts for 76% of total revenue for the base-load unit without REG, 63% for the base-load unit with REG, 52% for the peaking unit, 47% for the mid-merit unit without REG, and 28% for the mid-merit unit with REG. Despite a higher heat rate, the base-load unit's marginal production cost is low because it burns coal, a relatively inexpensive fuel. It would thus be expected to be a more frequent participant in the energy market. The mid-merit unit burns natural gas and thus has a higher production cost. As marginal cost approaches the MCP for energy, energy revenue falls, and participation in A/S markets becomes a more attractive option. For base-load and mid-merit units that cannot participate in the REG market, a larger fraction of total revenue will come from the energy market because the MCP for TMSR is typically much lower than the MCP for REG. Interestingly, the peaking unit obtains a greater share of its annual revenue from the energy market than does the mid-merit unit. This may occur for two reasons. First, although the natural gas-fired peaking plant also has high fuel costs, it has a significantly lower heat rate. Its production costs are thus intermediate between the base-load and mid-merit unit production costs. Second, and perhaps more importantly, the peaking unit can only participate in the TMNSR and 30M RES A/S markets, both of which tend to yield low premiums.

**Table 9-2**
**Percentage Contributions of Energy and Ancillary Services for Selected Plants in NYISO**

| | Coal-fired Unit with AGC | | Coal-fired Unit w/o AGC | | Natural Gas-fired Unit with AGC | | Natural Gas-fired without AGC | | Natural Gas-fired Combustion Turbine | |
|---|---|---|---|---|---|---|---|---|---|---|
| | REG/TMSR | | TMSR Only | | REG/TMSR | | TMSR Only | | TMNSR/30M Reserve | |
| Month | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % |
| JAN | 17.1 | 82.9 | 47.2 | 52.8 | 13.4 | 86.6 | 30.1 | 69.9 | 48.4 | 51.6 |
| FEB | 5.3 | 94.7 | 5.4 | 94.6 | 1.4 | 98.6 | 1.5 | 98.5 | 0.0 | 100.0 |
| MAR | 6.4 | 93.6 | 14.2 | 85.8 | -1.5 | 101.5 | -0.5 | 100.5 | 4.5 | 95.5 |
| APR | 29.4 | 70.6 | 89.4 | 10.6 | -4.5 | 104.5 | 31.4 | 68.6 | 81.2 | 18.8 |
| MAY | 67.4 | 32.6 | 96.2 | 3.8 | 38.9 | 61.1 | 90.2 | 9.8 | 93.3 | 6.7 |
| JUN | 90.4 | 9.6 | 99.6 | 0.4 | 76.3 | 23.7 | 98.1 | 1.9 | 99.0 | 1.0 |
| JUL | 82.0 | 18.0 | 98.7 | 1.3 | 30.5 | 69.5 | 83.3 | 16.7 | 92.6 | 7.4 |
| AUG | 93.6 | 6.4 | 99.1 | 0.9 | 82.6 | 17.4 | 96.8 | 3.2 | 97.6 | 2.4 |
| SEP | 91.3 | 8.7 | 98.6 | 1.4 | 21.3 | 78.7 | 59.7 | 40.3 | 92.1 | 7.9 |
| OCT | 96.9 | 3.1 | 99.1 | 0.9 | -3.8 | 103.8 | 16.5 | 83.5 | 90.6 | 9.4 |
| NOV | 96.4 | 3.6 | 99.8 | 0.2 | 58.1 | 41.9 | 88.6 | 11.4 | 94.9 | 5.1 |
| DEC | 98.3 | 1.7 | 100.0 | 0.0 | NA | NA | NA | NA | 81.9 | 18.1 |
| Annual | 63.0 | 37.0 | 76.2 | 23.8 | 27.6 | 72.4 | 46.6 | 53.4 | 52.1 | 47.9 |

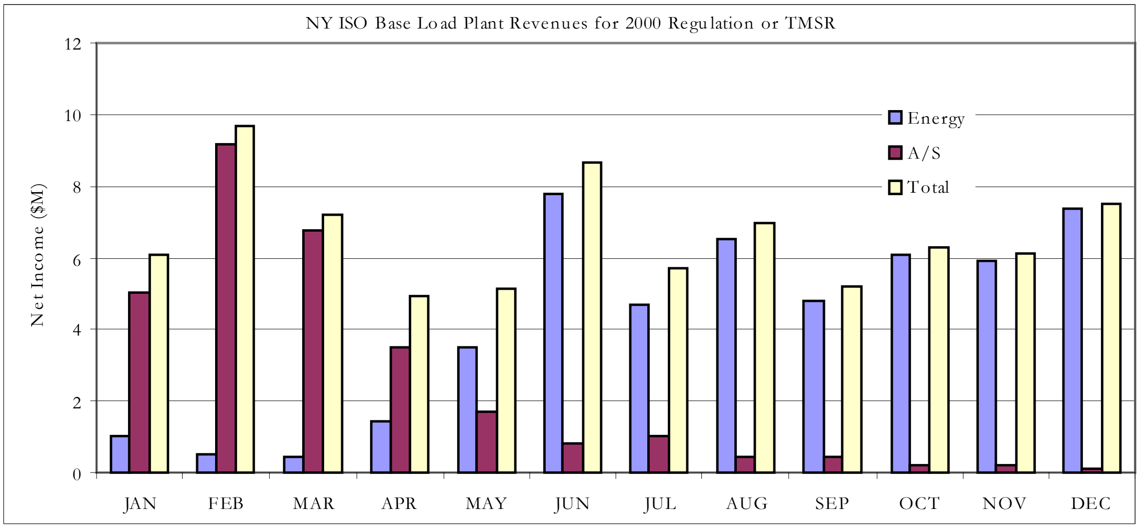


**Figure 9-4**
**NYISO Coal-fired Plant with AGC: Simulated Net Income**

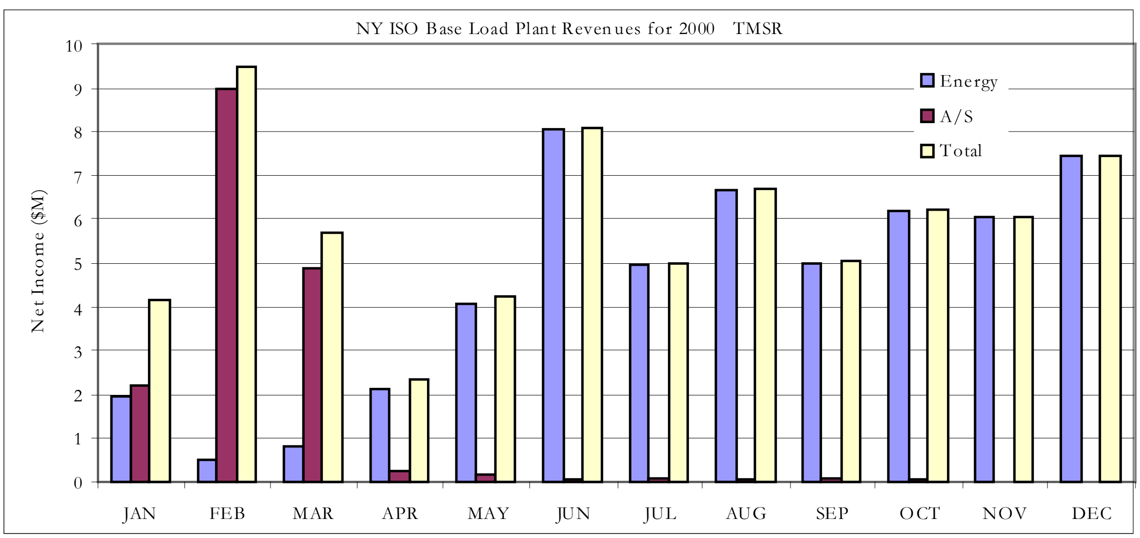


**Figure 9-5**
**NYISO Coal-fired Plant without AGC: Simulated Net Income**

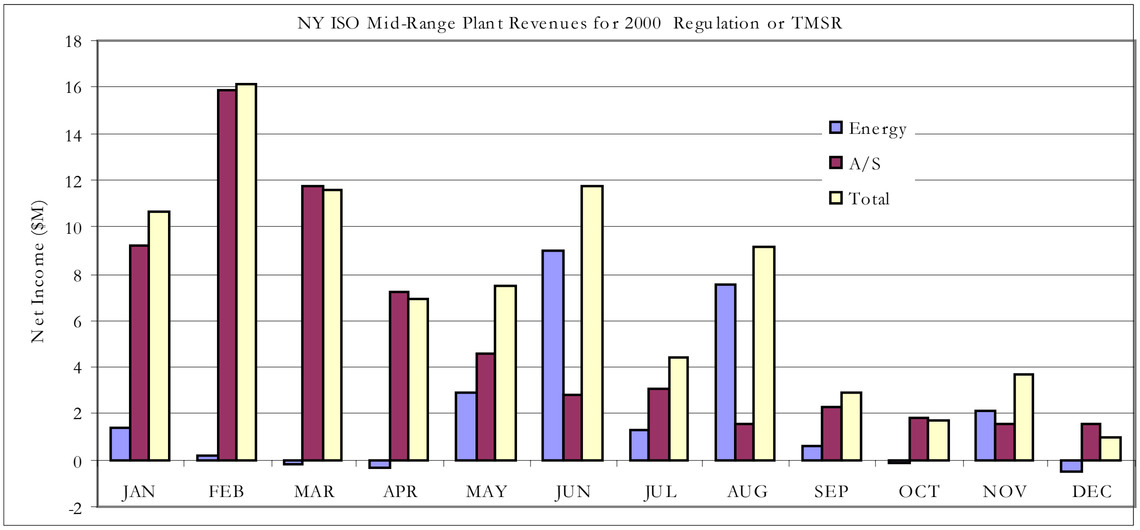


**Figure 9-6**
**NYISO Natural Gas-fired Plant with AGC: Simulated Net Income**

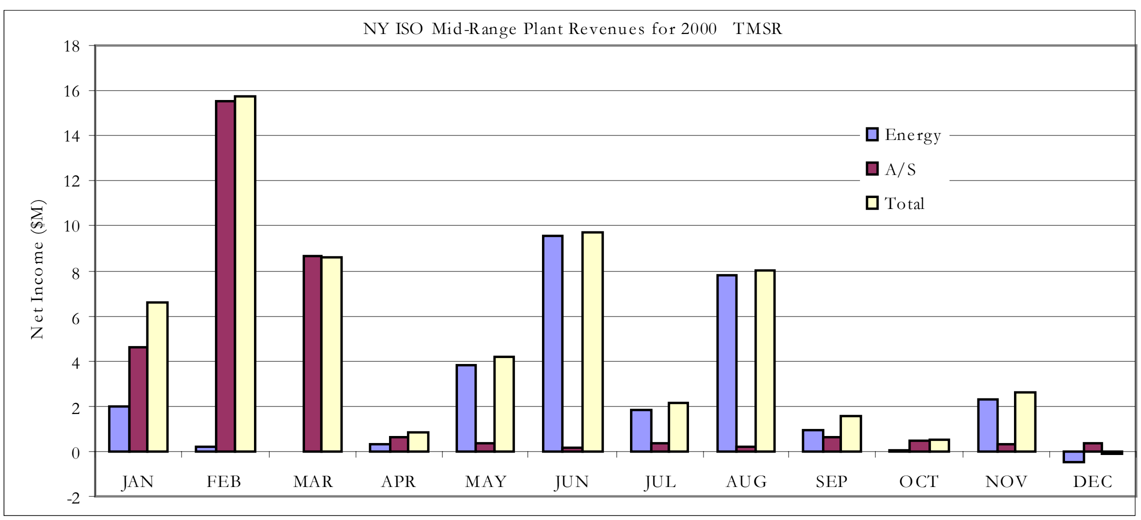


**Figure 9-7**
**NYISO Natural Gas-fired Plant without AGC: Simulated Net Income**

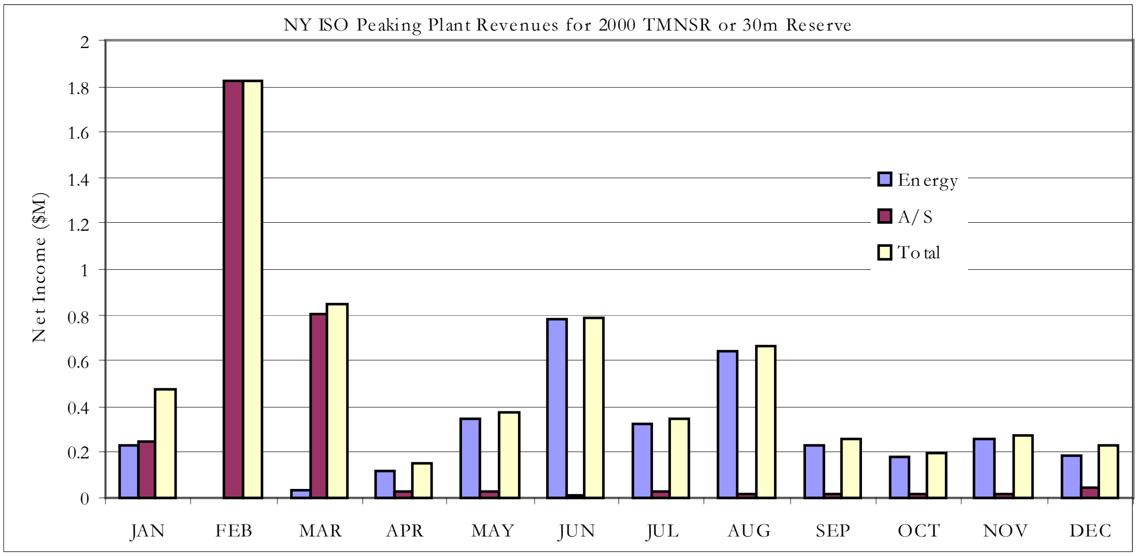


**Figure 9-8**
**NYISO Natural Gas-fired Combustion Turbine: Simulated Net Income**

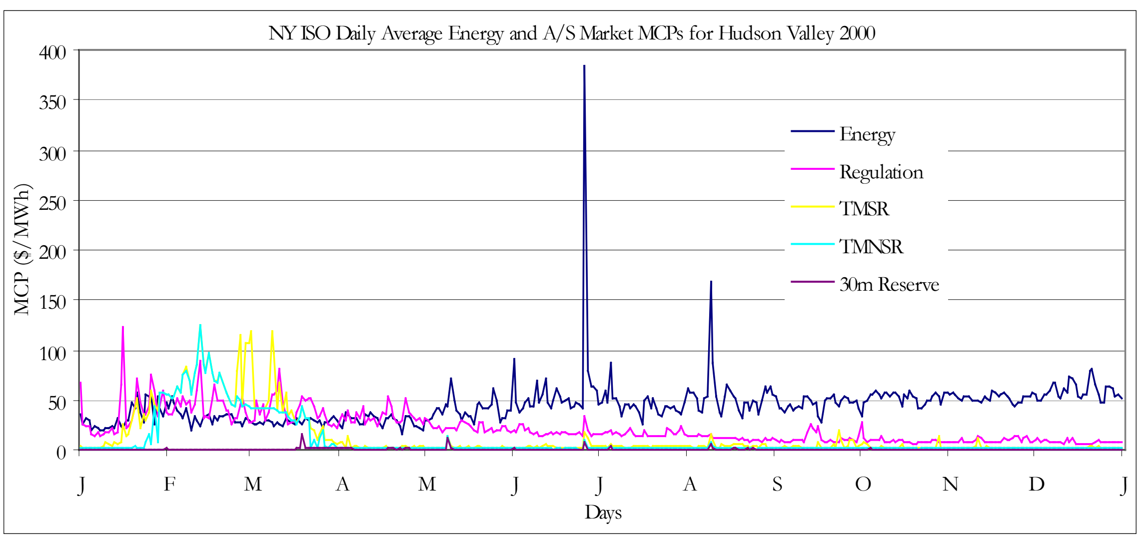


**Figure 9-9**
**NYISO Daily Average Energy and A/S Market-Clearing Prices**

### NEISO

The base-loaded coal plant has low variable operating costs, and thus is more competitive than the marginal plants and can earn significant profits in peak hours. Ancillary services nonetheless contribute to its profits (see Table 9- 2 and Figures 9-10 and 9-11). In April, this particular base load, if capable of regulation, can earn nearly half of the month's revenues by offering this ancillary service. If the plant is not capable of regulation, its earnings from Ancillary Services (spinning reserves are the best alternative to regulation) are somewhat lower in all months.

The mid-merit plant had distinctly different results in terms of its energy revenue, relative to the baseloaded plant (see also Table 9-2 and Figures 9-12 and 9-13). Due to its fuel costs from natural gas, and its mediocre efficiency, its energy revenues were much lower than those of the baseloaded plant. Note that in some months, the percentages concerning the mid-merit plant show 100% contribution from A/S, and 0% from energy. This indicates that while revenue was earned from energy, net income from providing the energy was negative. In eight months, its net revenue from energy was found to be negative, while May produced more revenue from energy than all other months combined. Assuming that it was capable of regulation, this plant could earn revenue from Ancillary Services to offset its poor performance in the energy market. In fact, even if energy revenues from the month of May were excluded, ancillary service earnings would allow the plant to earn a profit. Regulation would produce greater net revenue than spinning reserves.

The peaking plant would be expected to earn most of its revenues from energy in peak hours, regardless of whether it sold Ancillary Services (see again Table 9-2 and Figure 9-14). Thus, it would have a low capacity factor to begin with. The analysis performed showed that in most hours, the ancillary service market for non-spinning reserve or operating reserves would be more profitable than the energy market. Thus, the peaking plant would be expected to earn the highest percentage of its revenues from Ancillary Services. The analysis showed that twenty percent of revenue could be earned in the ancillary service markets.

**Table 9-3**
**Percentage Contributions of Energy and Ancillary Services for Selected Plants in NEISO**

| Month | Coal-fired Unit with AGC | | Coal-fired Unit w/o AGC | | Natural Gas-fired Unit with AGC | | Natural Gas-fired Unit w/o AGC | | Natural Gas-fired Combustion Turbine | |
|---|---|---|---|---|---|---|---|---|---|---|
| | REG/TMSR | | TMSR Only | | REG/TMSR | | TMSR Only | | TMNSR/30M Reserve | |
| | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % | Energy % | A/S % |
| JAN | 95.3 | 4.7 | 96.7 | 3.3 | 90.3 | 9.7 | 91.6 | 8.4 | 86.8 | 13.2 |
| FEB | 97.5 | 2.5 | 99.7 | 0.3 | 0.0 | 100.0 | 0.0 | 100.0 | 68.2 | 31.8 |
| MAR | 82.7 | 17.3 | 92.0 | 8.0 | 0.0 | 100.0 | 0.0 | 100.0 | 44.3 | 55.7 |
| APR | 55.9 | 44.1 | 58.4 | 41.6 | 0.0 | 100.0 | 0.0 | 100.0 | 12.8 | 87.2 |
| MAY | 94.3 | 5.7 | 95.1 | 4.9 | 96.4 | 3.6 | 93.6 | 6.4 | 91.0 | 9.0 |
| JUN | 91.6 | 8.4 | 92.9 | 7.1 | 0.0 | 100.0 | 0.0 | 100.0 | 44.3 | 55.7 |
| JUL | 97.1 | 2.9 | 99.9 | 0.1 | 0.0 | 100.0 | 0.0 | 100.0 | 80.3 | 19.7 |
| AUG | 98.2 | 1.8 | 100.0 | 0.0 | 66.2 | 33.8 | 97.1 | 2.9 | 97.2 | 2.8 |
| SEP | 98.8 | 1.2 | 99.8 | 0.2 | 0.0 | 100.0 | 0.0 | 100.0 | 91.5 | 8.5 |
| OCT | 99.7 | 0.3 | 100.0 | 0.0 | 0.0 | 100.0 | 0.0 | 100.0 | 90.3 | 9.7 |
| NOV | 99.9 | 0.1 | 100.0 | 0.0 | 11.3 | 88.7 | 92.8 | 7.2 | 95.9 | 4.1 |
| DEC | 99.2 | 0.8 | 99.4 | 0.6 | 0.0 | 100.0 | 0.0 | 100.0 | 87.3 | 12.7 |
| Annual | 95.1 | 4.9 | 99.5 | 0.5 | 61.1 | 38.9 | 74.6 | 25.4 | 79.3 | 20.7 |

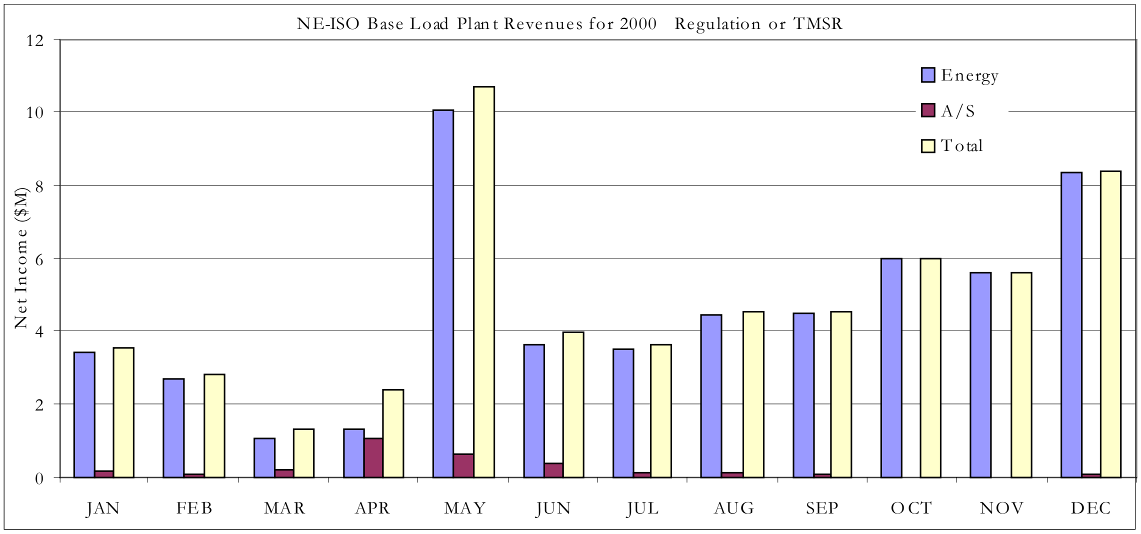


**Figure 9-10**
**NEISO Coal-fired Plant with AGC: Simulated Net Income**

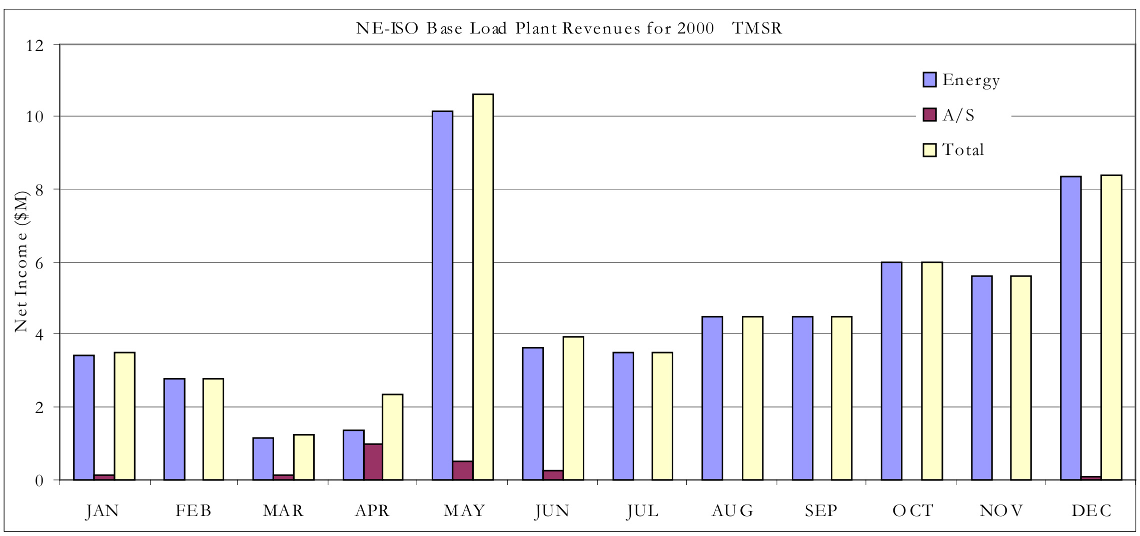


**Figure 9-11**
**NEISO Coal-fired Plant without AGC: Simulated Net Income**

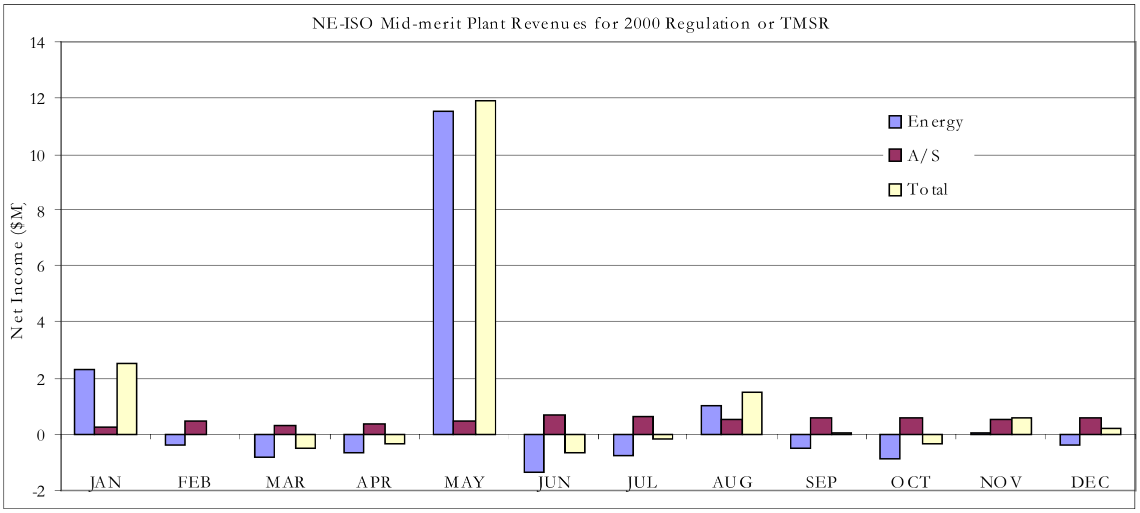


**Figure 9-12**
**Natural Gas-fired Plant with AGC: Simulated Net Income**

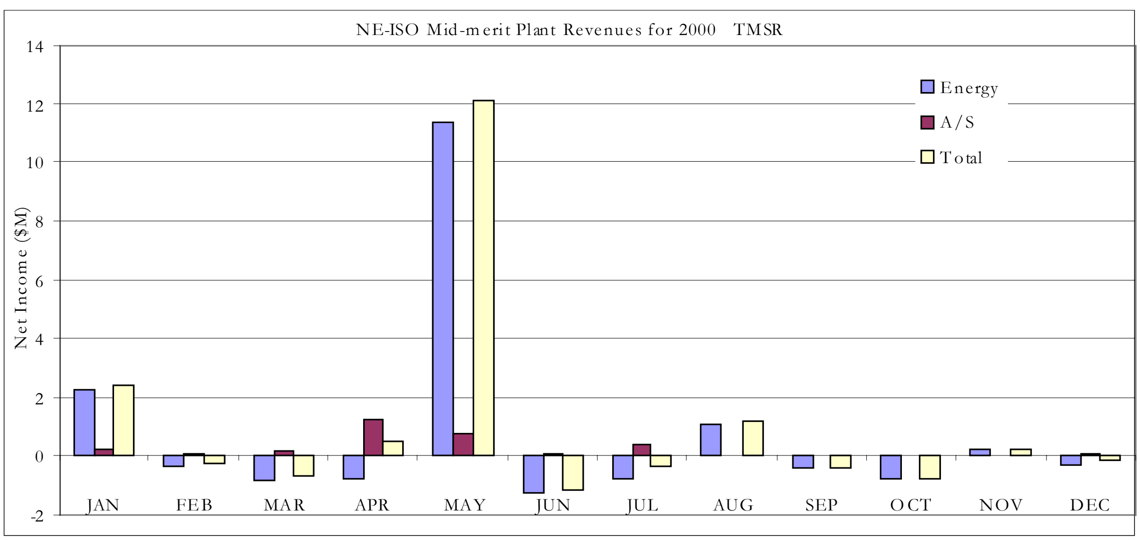


**Figure 9-13**
**Natural Gas-fired Plant without AGC: Simulated Net Income**

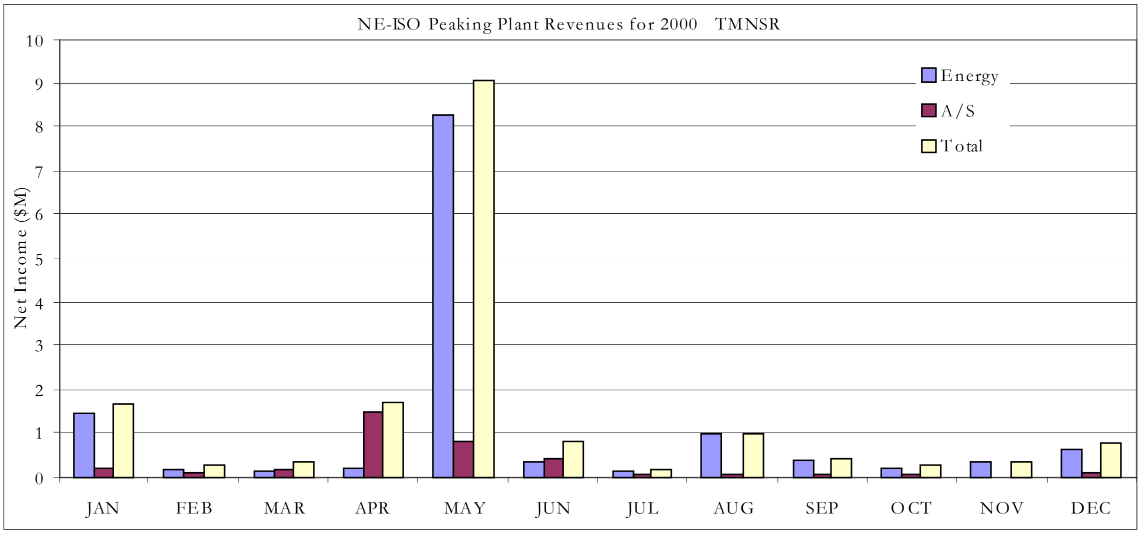


**Figure 9-14**
**Natural Gas-fired Combustion Turbine: Simulated Net Income**

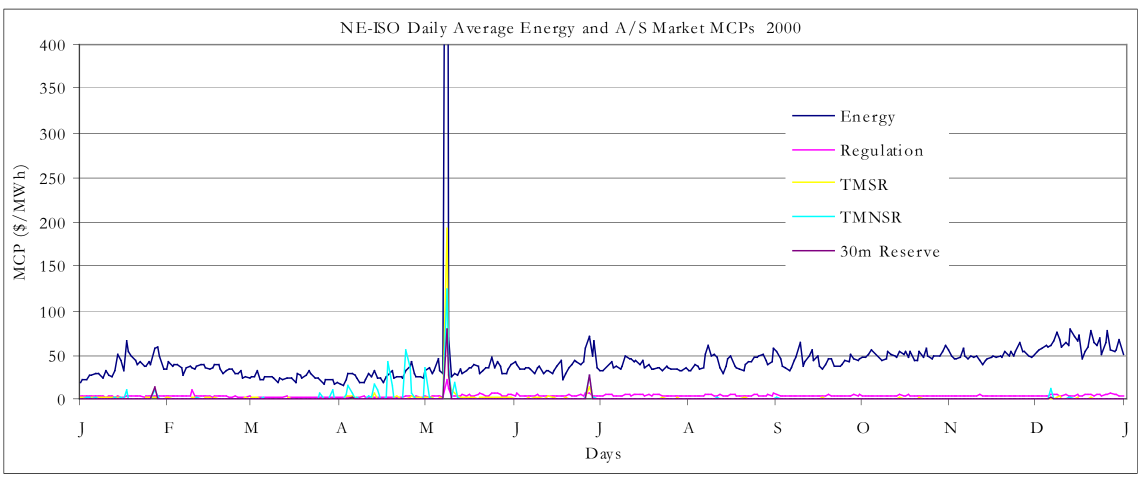


**Figure 9-15**
**NEISO Daily Average Energy and A/S Market Market-Clearing Prices**

## *CAISO*

For base-load and mid-merit plants in CA, the capability for regulation is a prime source of profit (see Table 9-3) (In some instances, the percentage for energy is negative, reflecting the situation that the net income from energy is negative. Note that as with New England results, in some months, the percentages show 100% contribution from A/S, and 0% from energy. Again, while revenue was earned from energy, net income from providing the energy was negative.). In most months, assuming the plant can provide regulation, A/S has a much larger contribution to profits than energy. On an annual basis, the share of A/S is 72% for base-load and 86% for mid-merit. Without regulation, however, energy is the dominant source of profit. On an annual basis, the share of A/S is 10% for base-load and 27% for mid-merit. By contrast, the bulk of profits of a peaker plant come from energy (see also Table 9-3). From February to June, most profits are from replacement, but in January and from July to November, most profits are from energy. Non-spin provides 59% of profits in December. On an annual basis, the share of energy is 53%, non-spin, 33%, and replacement, 14%.

As in the other ISO areas, the conclusions on the percentage shares have to be combined with an assessment of the levels (see Figures 9-16 to 9-22). Movements in levels are uncorrelated to those in MCPs. For example, for a base-load plant capable of regulation, A/S has a share of 85% in July, and its average value is $30.29M. In December, its share is down to 57%, but its value is $57.53M (see Figure 9-16), even though A/S prices are not noticeably different between July and December (see Figure 9-18).

**Table 9-4**
**Percentage Contributions of Energy and Ancillary Service for Selected Plants in California**

| Month | Base-load | | | | Mid-merit | | | | Peaking | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Coal-fired Unit with AGC | | Coal-fired Unit without AGC | | Natural gas-fired Unit with AGC | | Natural gas-fired Unit without AGC | | Natural gas-fired Combustion Turbine without AGC | | |
| | Energy | A/S | Energy | A/S | Energy | A/S | Energy | A/S | Energy | NonSpin | Replace |
| Jan | 48% | 52% | 0% | 100% | 36% | 64% | 0% | 100% | 79% | 10% | 11% |
| Feb | 30% | 70% | 95% | 5% | 13% | 87% | 90% | 10% | 1% | 39% | 60% |
| Mar | 0% | 100% | 0% | 100% | -13% | 113% | 0% | 100% | 2% | 47% | 50% |
| Apr | -27% | 127% | 44% | 56% | -33% | 133% | 46% | 54% | 0% | 7% | 93% |
| May | 13% | 87% | 86% | 14% | 15% | 85% | 16% | 84% | 37% | 17% | 45% |
| Jun | 28% | 72% | 0% | 100% | 12% | 88% | 77% | 23% | 33% | 23% | 44% |
| Jul | 15% | 85% | 25% | 75% | 8% | 92% | 0% | 100% | 64% | 26% | 10% |
| Aug | 32% | 68% | 84% | 16% | 24% | 76% | 80% | 20% | 66% | 30% | 4% |
| Sep | 12% | 88% | 51% | 49% | 9% | 91% | 81% | 19% | 63% | 27% | 10% |
| Oct | 55% | 45% | 97% | 3% | 26% | 74% | 48% | 52% | 76% | 22% | 3% |
| Nov | 82% | 18% | 96% | 4% | 56% | 44% | 0% | 100% | 91% | 8% | 1% |
| Dec | 43% | 57% | 56% | 44% | 11% | 89% | 12% | 88% | 33% | 59% | 8% |
| Average | 28% | 72% | 90% | 10% | 14% | 86% | 73% | 27% | 53% | 33% | 14% |

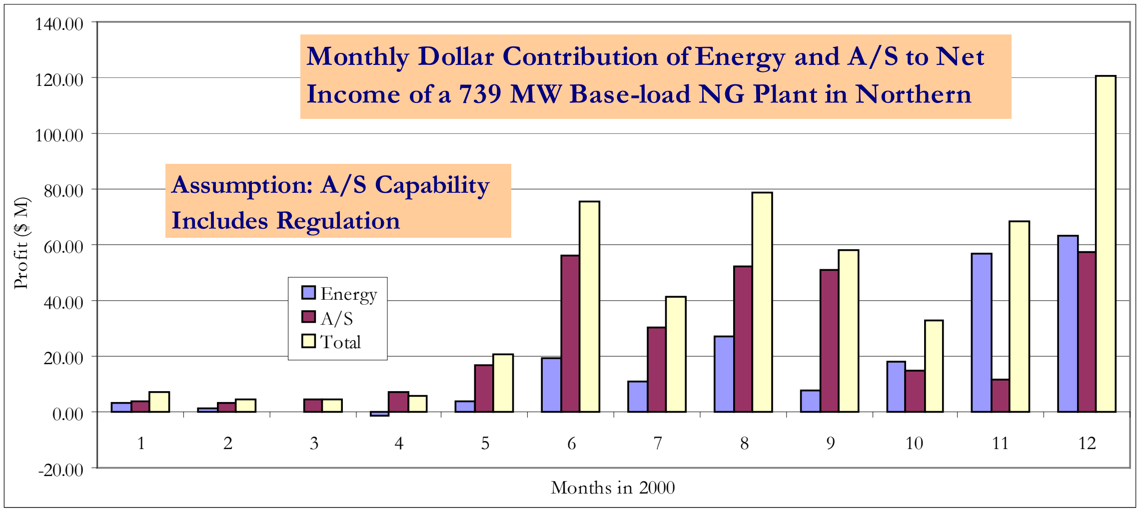


**Figure 9-16**
**Northern California Gas-fired Plant with AGC: Simulated Net Income**

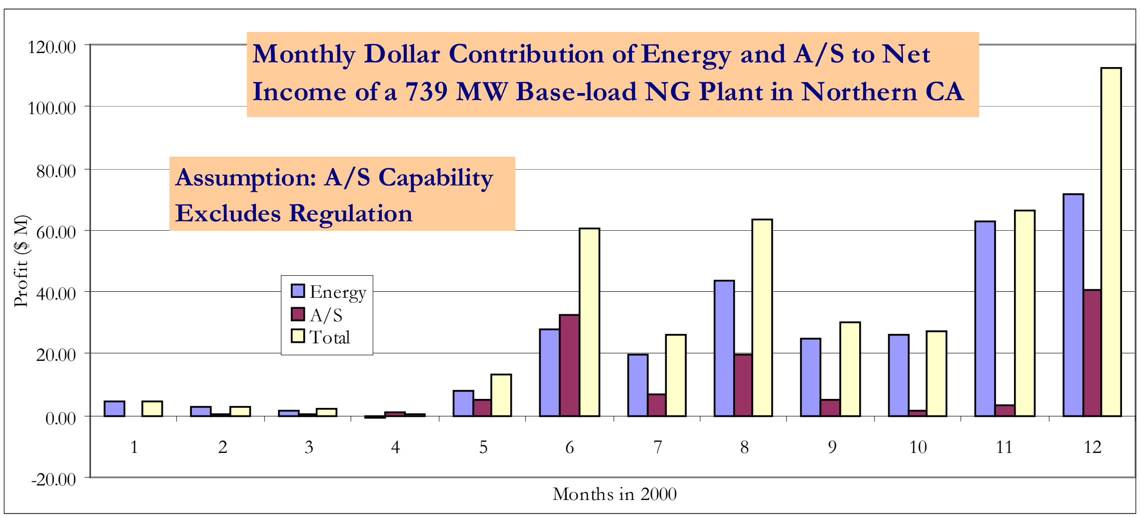


**Figure 9-17**
**Northern California Gas-fired Plant without AGC: Simulated Net Income**

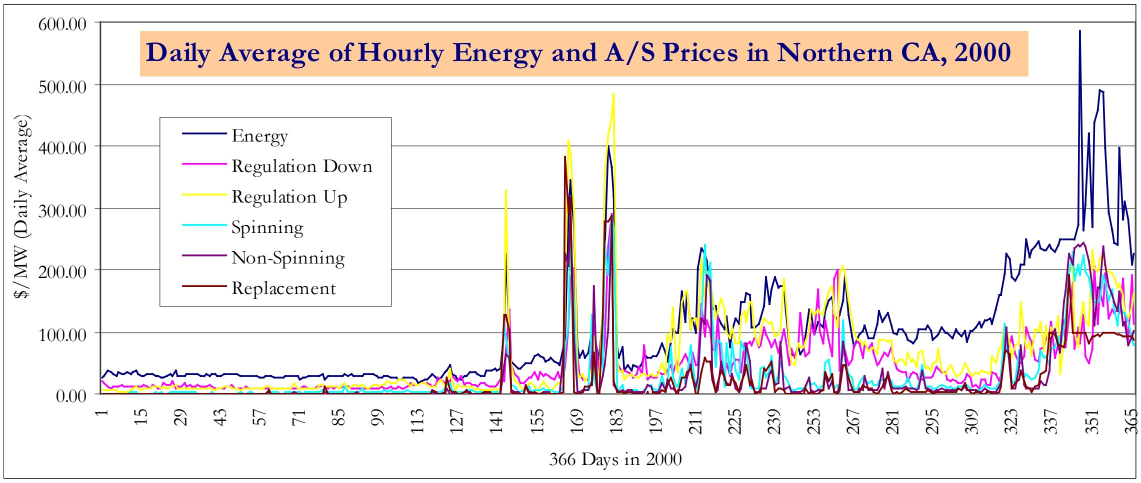


**Figure 9-18**
**Northern California Energy and Ancillary Services Market Clearing Prices**

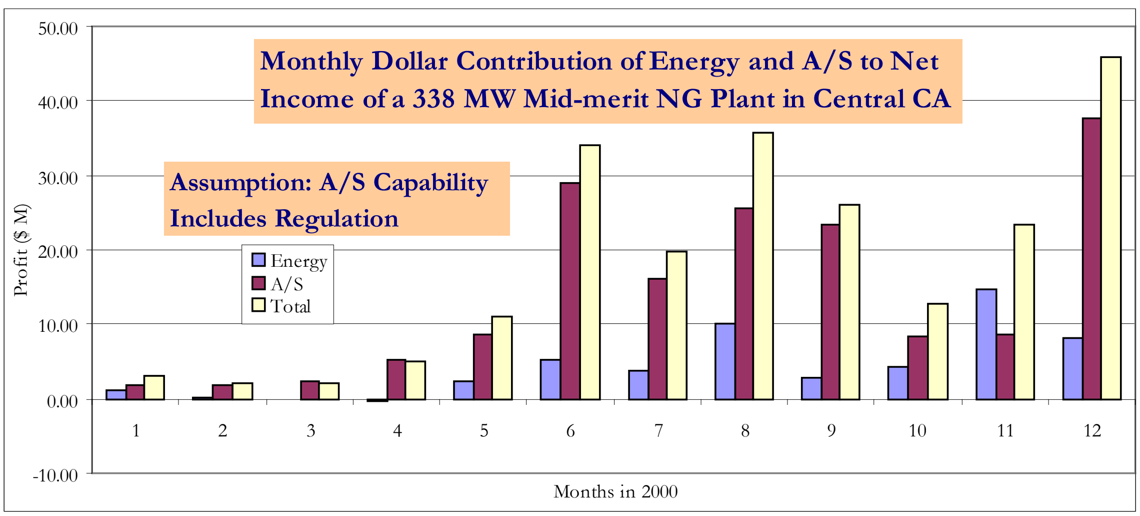


**Figure 9-19**
**Central California Gas-fired Plant with AGC: Simulated Net Income**

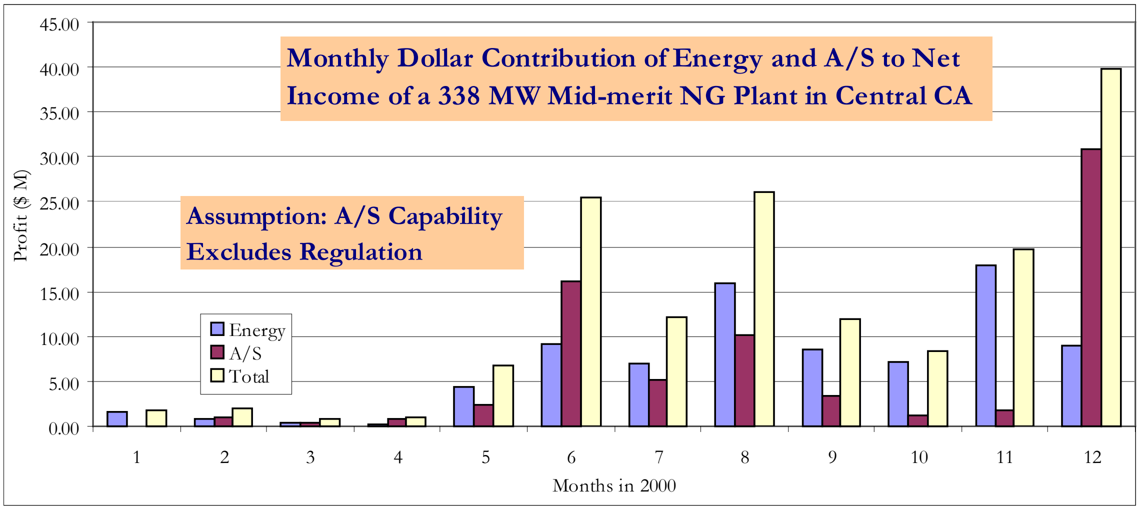


**Figure 9-20**
**Central California Gas-fired Plant without AGC: Simulated Net Income**

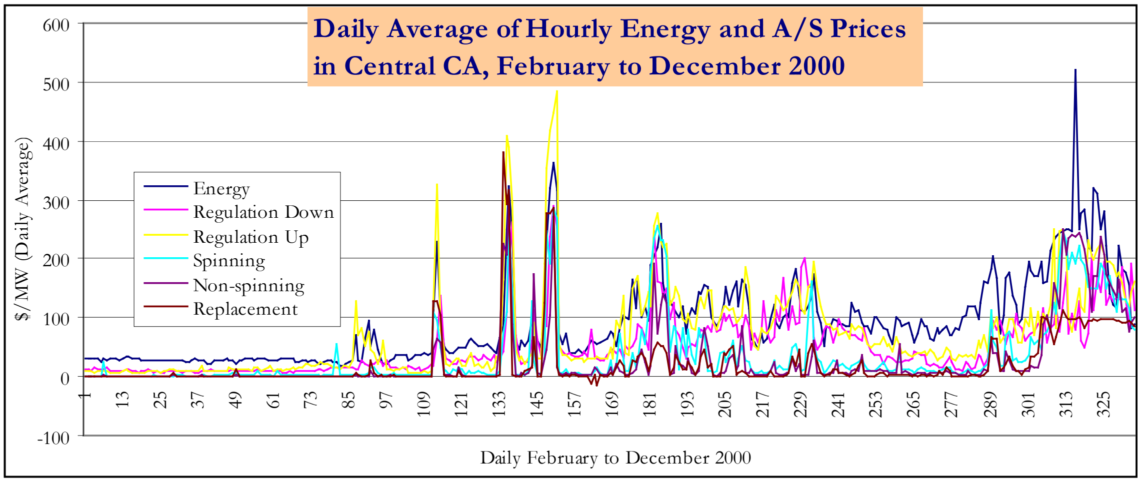


**Figure 9-21**
**Central California Energy and Ancillary Services Market-Clearing Prices**

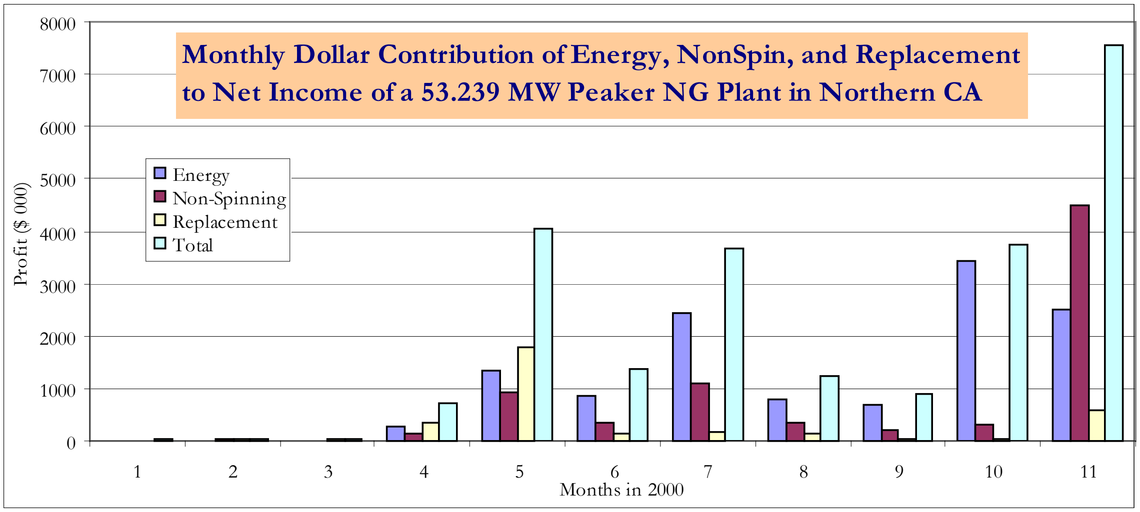


**Figure 9-22**
**Northern California Gas-fired Combustion Turbine: Simulated Net Income**

## *ERCOT*

A/S markets are most important for mid-merit and peaker plants in ERCOT (see Table 9-5). A base-load unit earns only up to 20% of income from A/S. However, a mid-merit plant and a peaker earn up to half of their income from A/S. In September, for example, the mid-merit plant earns 49% from A/S, the peaker, 67%. Apart from a few spikes, energy and A/S prices were fairly stable over the sample period covering September to October 2001 (see Figures 9-23 and 9-24).

**Table 9-5**
**Percentage Contributions of Energy and Ancillary Services for Selected Plants in ERCOT**

| Month | Base | | Mid | | Peak | |
|---|---|---|---|---|---|---|
| | Energy | A/S | Energy | A/S | Energy | A/S |
| September | 83% | 17% | 51% | 49% | 33% | 67% |
| October | 90% | 10% | 49% | 51% | 100% | 0% |
| Total | 88% | 12% | 50% | 50% | 53% | 47% |

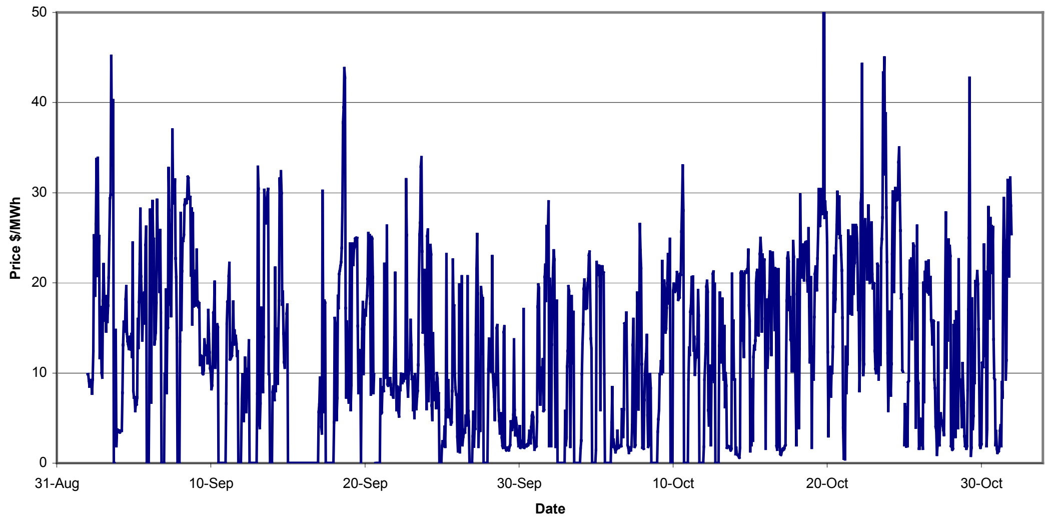


**Figure 9-23**
**Imbalance Energy Prices for ERCOT**

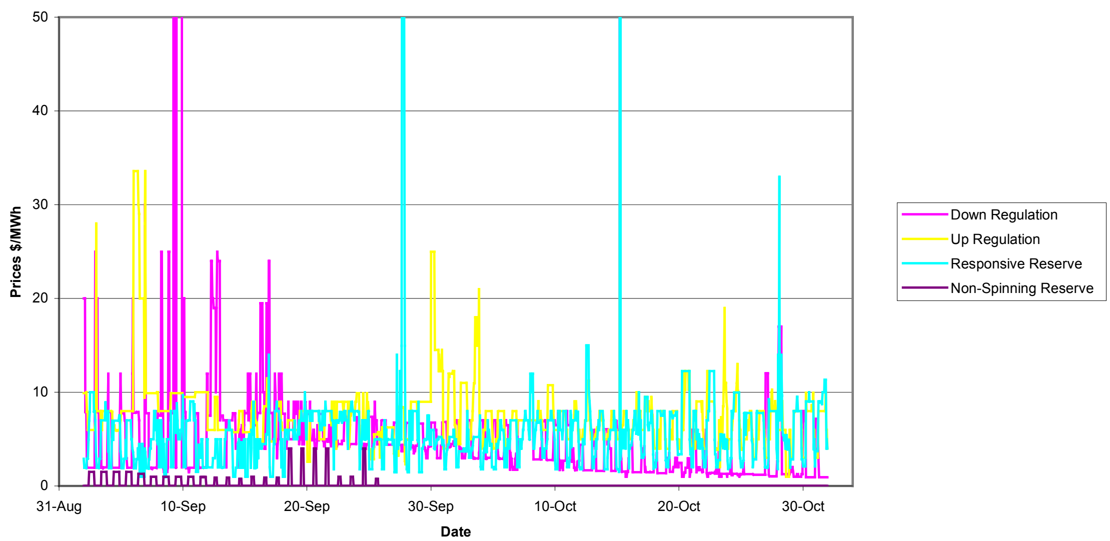


**Figure 9-24**
**Ancillary Service Prices for ERCOT**

# 10
# SUMMARY AND CONCLUSIONS

Six Ancillary Services (FERC terminology) or Interconnected Operation Services (IOS, NERC terminology) were tested by EPRI over the years 1998-2000. These tests are covered in detail in EPRI reports (Ref. 5-7). The tests which were conducted showed that the certification and performance tests recommended by NERC were practical and made good sense. In four cases, (Regulation, Load following, Contingency Reserves – Spinning and Supplemental) the testing could be performed with existing, station instrumentation and without interrupting daily unit operation. Two IOS's, (Black Start and Reactive Supply from a Generation Source) turned out to require unit shut down and, for this reason, were not performed specifically for demonstration, but the EPRI team worked work with a utility a utility to assess a then recently performed black start test against NERC requirements.

The present report was initiated by EPRI to create a "handbook" on IOS testing as guidance for future testing either by EPRIsolutions, or the generating entities. The report also emphasizes items that may not fit naturally into the previous test reports. The following items were covered.

- Checking the validity of the previous EPRI tests against the new Version of NERC IOS Document since tests were based on previous versions of this document.
- Summarizing lessons learned from all six tests
- Providing recommendations to increase the effectiveness of future testing
- Providing examples of Check Lists for the tests which will facilitate future testing of the services.
- Offering Data Evaluation Templates with Sample Test Data.
- Contrasting the requirements of Ancillary Services testing and qualifications independent systems operators (ISO) from across the nation: California, Texas and New York.
- This report also covered the issue of voltage control from generators (the present service of this Ancillary Service), as well as its provision discussed its from transmission systems equipment, such as FACTS.

The following summarizes the complexity and effort of testing of the six IOS's and the value to generators for participating in competitive Ancillary Services markets.

## Regulation

Testing was done entirely with station instrumentation and data acquisition equipment. Pre-programmed dispatch signals sent from the Area Generation Control (AGC) were used to put a unit through the load changes. No disturbance occurred in the plant or on the grid. The workload was very modest. The utility was very satisfied with the ease of testing and the demonstration of expected capability.

## Load Following

The experience and results were the same as for 1.above.

## Contingency Reserve – Spinning

This IOS was demonstrated by initiation from the unit control room at a time agreeable to the AGC. Station instrumentation and data acquisition equipment were fully satisfactory for the testing. The utility was satisfied with the test, which showed that the capability of the unit was not as good as expected.

## Contingency Reserve – Supplemental.

The experience and results were the same as for 3.above.

## Reactive Supply from Generation Sources

Demonstration of a unit's specific performance characteristics must be done off-line and were judged too demanding for a demonstration test. Only the on-line performance was demonstrated and did not cause interference with the unit's operation or on the grid.

## Black Start

As originally specified by NERC, this testing was so demanding that no utility could be found who was willing to do this test for demonstration purposes. NERC has recently subdivided the testing into three separate phases and removed a requirement of surprise, which should make the testing more acceptable. We were able to find a utility that had recently performed a complete black start test and review its data. It showed that essentially all NERC requirements had been demonstrated and that very significant lessons had been learned. The conclusion was that only with fairly frequent training and practice can the black start be relied upon to perform as planned.

Finally, as to the requirements at the different ISO's, there seems to be a lot of similarities, and strong influence by NERC's recommendations. One has to note the wealth of names for Ancillary Services among the different ISO. Most of them fall in the categories specified by FERC and NERC. All five ISO's whose documents we reviewed have markets in Ancillary Services and specifications for qualification and performance testing. Finally, the EPRI sponsored testing demonstrated the majority of these requirements and the experience gained should be helpful to suppliers wishing to evaluate their units and obtain certification

The requirement or need for certification and performance testing of IOS's may have been reduced temporarily by the fact that NERC has elected not to issue its draft Policy 10 as such but only as a "Reference Document" included in its Operating Manual. If, however, the deregulation of the nation's electricity supply continues as in the recent past, trade in IOS's will be required. To achieve an orderly trade in IOS's they will not only need to be defined, but also be measurable both in quality and quantity. At that time testing for "Certification" of capability and for "Performance" of quality and quantity will be needed. We hope that this handbook will prove to be a valuable guide to future testing.

## Income from Energy and Ancillary Services

An evaluation of the contribution to earnings from selling A/S vs. energy is presented in Chapter 9. Baseload, mid-merit and peaking unit plants were selected in each of the four regions with competitive A/S markets: New York ISO, New England ISO, California and Texas (ERCOT). Energy and A/S prices were obtained for 2000 and, in the case of ERCOT, for two months after the initiation of its A/S market in August 2001. Using a realistic set of decision rules, the generators sell into the most profitable markets. Results are summarized monthly, as well as for the full year. The baseload and mid-merit units sell energy or ten-minute spinning reserves, and if equipped with AGC, may also sell regulation. The peaking units sell energy or ten-minute non-spinning reserves, or 30-minute reserves. The annual income shares are summarized in Table x-y. The monthly patterns of earnings are in many instances quite divergent from the annual totals. The possible value of participating in both markets is evident from this summary. Baseload units capable of regulation or spin may earn up to 40% of their income from A/S. Mid-merit units capable of regulation or spin may earn up to three-fourths of their income from A/S. Peaker units capable of ten-minute non-spinning reserve may earn up to 48% of their income from A/S.

**Table 10-1**
**Summary of Contributions to Income from Energy and A/S for Different Plant Types**

| Plants | | Markets | NYISO | NEISO | ERCOT | CA |
|---|---|---|---|---|---|---|
| Baseload | With Regulation | Energy | 63% | 95% | 88% | 28% |
| | | A/S | 37% | 5% | 12% | 72% |
| | No Regulation | Energy | 76% | 99% | 91% | 90% |
| | | A/S | 24% | 1% | 9% | 10% |
| Mid-merit | With Regulation | Energy | 28% | 61% | 50% | 14% |
| | | A/S | 72% | 39% | 50% | 86% |
| | No Regulation | Energy | 47% | 75% | 50% | 73% |
| | | A/S | 53% | 25% | 50% | 27% |
| Peaker (No Regulation) | | Energy | 52% | 79% | 53% | 53% |

# 11
# GLOSSARY OF TERMS

The following are the official NERC definitions of the terms used in this document. They are extracted from Reference 4.

**BULK ELECTRIC SYSTEM.** The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission facilities are interconnected.

**CONTINGENCY RESERVE – SPINNING.** The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation synchronized to the system and fully available to serve load within $T_{DCS}$ minutes of the contingency event; or
- Load fully removable from the system within $T_{DCS}$ minutes of the contingency event.

**Contingency Reserve – Supplemental.** The portion of Contingency Reserve provided from IOS Resources consisting of:

Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within $T_{DCS}$ minutes of the contingency event; or

Load fully removable from the system within $T_{DCS}$ minutes of the contingency event.

**CONTINGENCY RESERVE.** The provision of capacity deployed by the OPERATING AUTHORITY to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. CONTINGENCY RESERVES are composed of CONTINGENCY RESERVE–SPINNING and CONTINGENCY RESERVE–SUPPLEMENTAL.

**CONTROL AREA.** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its interchange schedule with other CONTROL AREAS and contributes to frequency regulation of the INTERCONNECTION.

**DEPLOY.** To authorize the present and future status and loading of resources. Variations of the word used in this IOS Reference Document include DEPLOYMENT and DEPLOYED.

**DYNAMIC TRANSFER.** The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one CONTROL AREA into another.

**FREQUENCY RESPONSE.** The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION.

**INTERCONNECTED OPERATIONS SERVICE (IOS).** A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS.

**INTERCONNECTION.** Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

**IOS RESOURCE.** The physical element(s) of the electric system which is (are) capable of providing an IOS. Examples of an IOS RESOURCE may include one or more generating units, or a portion thereof, and controllable loads.

**IOS SUPPLIER.** An entity that offers to provide, or provides, one or more IOS.

**LOAD FOLLOWING.** The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that is dispatched within a scheduling period by the OPERATING AUTHORITY.

**MANEUVERABILITY.** The ability of an IOS RESOURCE to change its real- or reactive-power output over time. MANEUVERABILITY is characterized by the ramp rate (e.g., MW/minute) of the IOS RESOURCE and, for REGULATION, its acceleration rate (e.g., MW/minute$^2$).

**OPERATING AUTHORITY.** An entity that:

Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and

Is accountable to NERC and one or more Regional Reliability Councils for complying with NERC and Regional Policies; and

Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

**Operating Reserve.** That capability above firm system demand required to provide regulation, load forecasting error, equipment forced and scheduled outages, and other capacity requirements.

**Regulation**. The provision of generation and load response capability, including capacity, energy, and Maneuverability, that responds to automatic controls issued by the Operating Authority.

**Reactive Power Supply from Generation Sources**. The provision of reactive capacity, reactive energy, and responsiveness from IOS Resources, available to control voltages and support operation of the Bulk Electric System.

**System Black Start Capability**. The provision of generating equipment that, following a system blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. System Black Start Capability serves to provide an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.

# 12
# REFERENCES


1. FERC Order 888. Washington, D.C. April 24, 1996.
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# A
# VOLTAGE CONTROL WITH GENERATORS

Generators are the backbone of voltage control. This section will describe the use of generators for reactive power production and absorption. The section will also illustrate the use of a graphical tool (reactive capability curve) for determining the power production limits of a generator.

## Excitation Systems

The excitation systems of the generating units on the power system are used to control the overall voltage profile of the power system. Changes made to generator terminal voltages are subsequently spread throughout the power system. Figure A-1 illustrates the major elements of a generator's excitation system. The excitation system is used to control the terminal voltage and MVAr production of the generator.

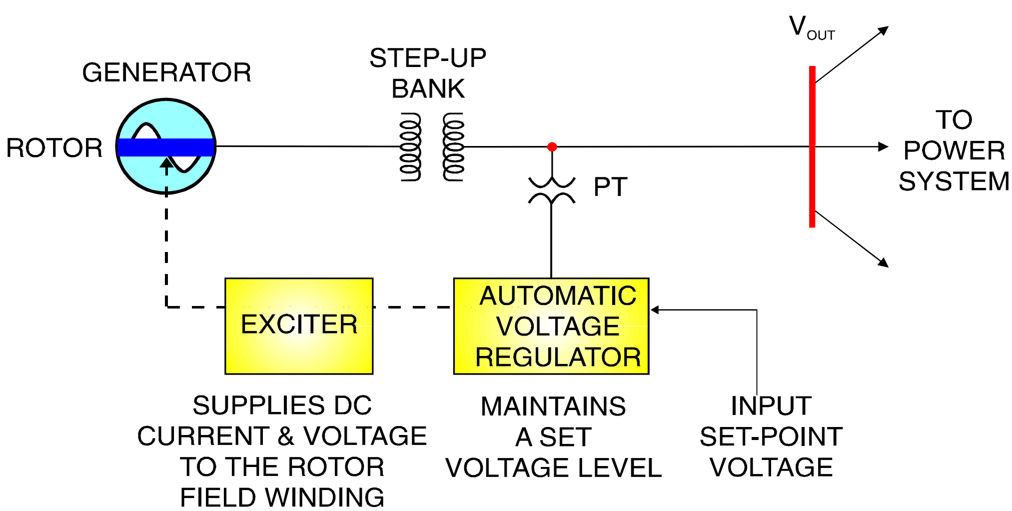


**Figure A-1**
**Block Diagram of a Generator Excitation System**

The automatic voltage regulator (AVR) senses the voltage level at the generator terminals via a potential transformer (PT). Circuitry is included in the voltage regulator to compare the voltage measured to a set-point voltage. If the measured voltage is lower than the set point the AVR will cause the excitation system to increase the DC excitation current. This DC current is applied to the generator's rotor field winding. If the voltage measured is higher than the set-point the excitation system will lower the DC excitation current applied to the field winding. Plant operators control the voltage level of the generator by selecting the proper AVR set-point.

### *Method of Voltage Regulation*

Voltage regulators can be operated in an automatic mode (as described above) or in a manual mode. When in automatic mode the excitation system will try to maintain a specified bus voltage. When in manual mode a constant magnitude of field current will be provided to the field winding. A voltage regulator in manual mode makes no attempt to control a bus voltage magnitude.

From a system operations perspective all voltage regulators should remain in automatic mode. This ensures the generators will assist with the control of system voltages. When voltage regulators are placed in a manual mode, a major voltage control tool (the generator) is eliminated from the voltage control process. Power plant operators may occasionally need to place voltage regulators in manual mode. The voltage regulators should be returned to automatic mode as soon as possible.

## Reactive Capability Curves

The MVAr support capabilities of each generator are defined by each unit's reactive capability curve. Figure A-2 is an example of a generator's reactive capability curve. This plot illustrates the limits of acceptable generator operation. The horizontal axis of the plot represents the MW produced by the generator. The positive vertical axis represents MVAr produced by the generator and the negative vertical axis represents MVAr absorbed by the generator.

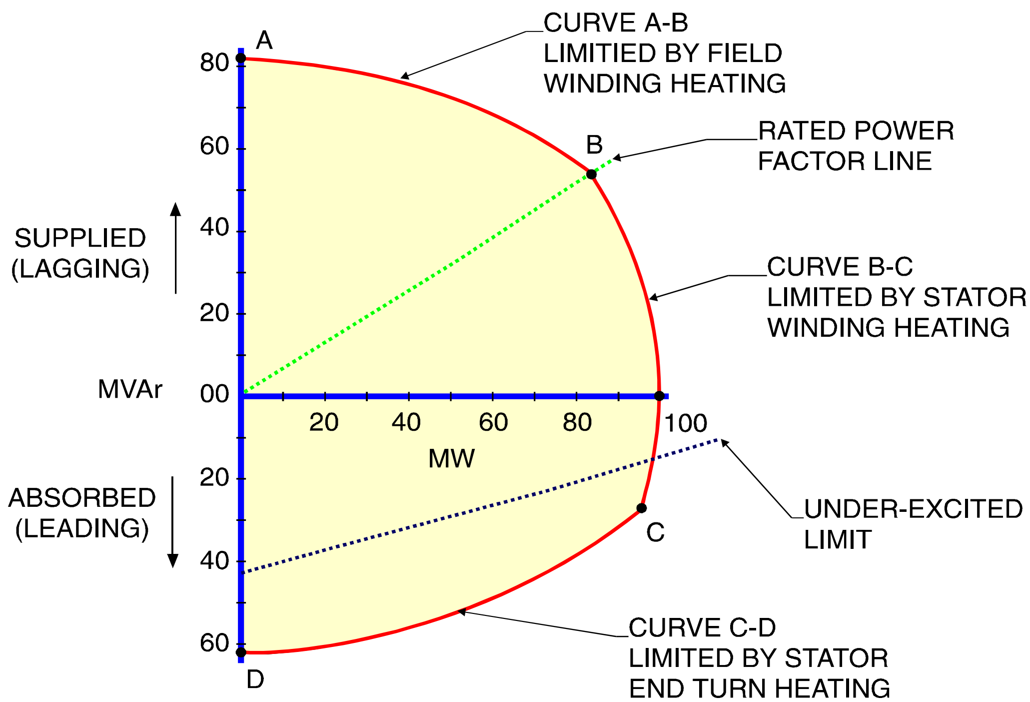


**Figure A-2**
**Reactive Capability Curve**

Generators must be operated within the limits of their capability curves. There are three circular sections to a typical capability curve. Note the section labeled “Curve A-B” in Figure 2. The generator can not exceed this curve section limits or field winding thermal damage may occur. Note the section labeled “Curve B-C”. The generator must stay within the confines of this curve section or stator winding thermal damage may occur. The final section is labeled “Curve C-D”. The generator must stay within this section of the curve or thermal damage to the end-turn area of the stator core could occur. When operating in the upper half of the curve the generator is supplying reactive power to support the system voltage. This type of operation is called lagging or overexcited. When operating in the lower half of the curve the generator is absorbing reactive power to lower system voltage. This type of operation is called leading or underexcited operation.

Also illustrated in Figure A-2 is an under-excitation limit line. This line represents a limit to how far the generator may be taken into the leading region of operation. The farther a generator operates in the lead, the weaker the magnetic bond between the generator and the power system. As a generator’s magnetic bond strength reduces the likelihood of a generator losing synchronism increases. Many generators will have protective systems that prevent their operation deep within the leading region of their capability curves.

Each generator in the power system has a reactive capability curve. Plant operators are primarily responsible for keeping the generator MW and MVAr output within the limits of its capability curve. Generators are often equipped with protective relays to detect operation significantly outside of the rated capability curve of the unit. When activated, these relays may initiate a unit alarm, automatic runback, or unit trip.

### *Thermal Unit Reactive Capability Curve*

Figure A-3 is a capability curve for an actual thermal unit. An important feature of this capability curve is that there are actually a series of four capability curves illustrated. This is typical for a steam unit as the active and reactive power production capability of the unit is often a function of the stator’s hydrogen cooling system pressure. The greater the hydrogen pressure the greater the capability of the unit. Note the hydrogen pressures of the unit illustrated in Figure A-3 vary from 5 psig to 45 psig. Also note the series of straight lines crossing the curve. These are constant power factor lines. All points along one of these lines have the same power factor.

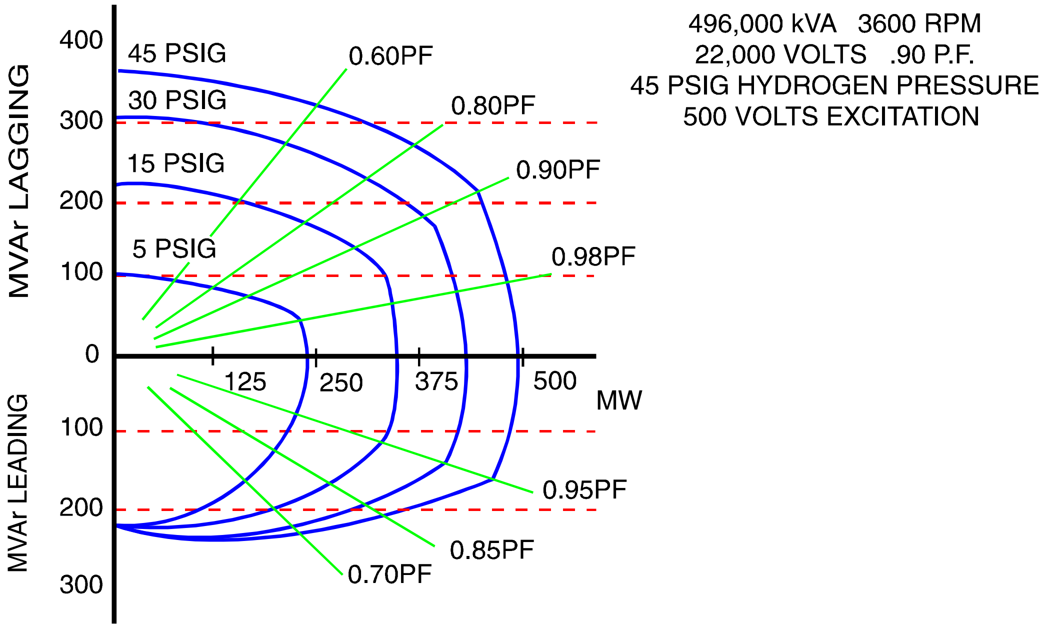


**Figure A-3**
**Actual Thermal Unit Reactive Capability Curve**

A system operator could use the capability curve of Figure A-3 to estimate the remaining reactive capability of the generator. You must first know the current hydrogen pressure of the unit and the current MW generation. Plot the current MW generation on the curve and determine the remaining reactive capability by noting the reactive limits from the appropriate capability curve. For example, assume this unit is presently operating at 375 MW and 100 MVAr with a hydrogen pressure of 45 psig. From the figure you can determine that the remaining reactive capability is approximately 170 MVAr in the lagging direction and 300 MVAr in the leading direction.

### *Hydro Unit Reactive Capability Curve*

Figure A-4 is an actual reactive capability curve for a hydro-electric generator. The curve shape is similar to the thermal unit of Figure A-3 with the exception of the leading region. Hydro units are water cooled and not subject to stator end-turn thermal limitations. The leading reactive capability of a typical hydro unit is therefore much greater than that of a thermal unit.

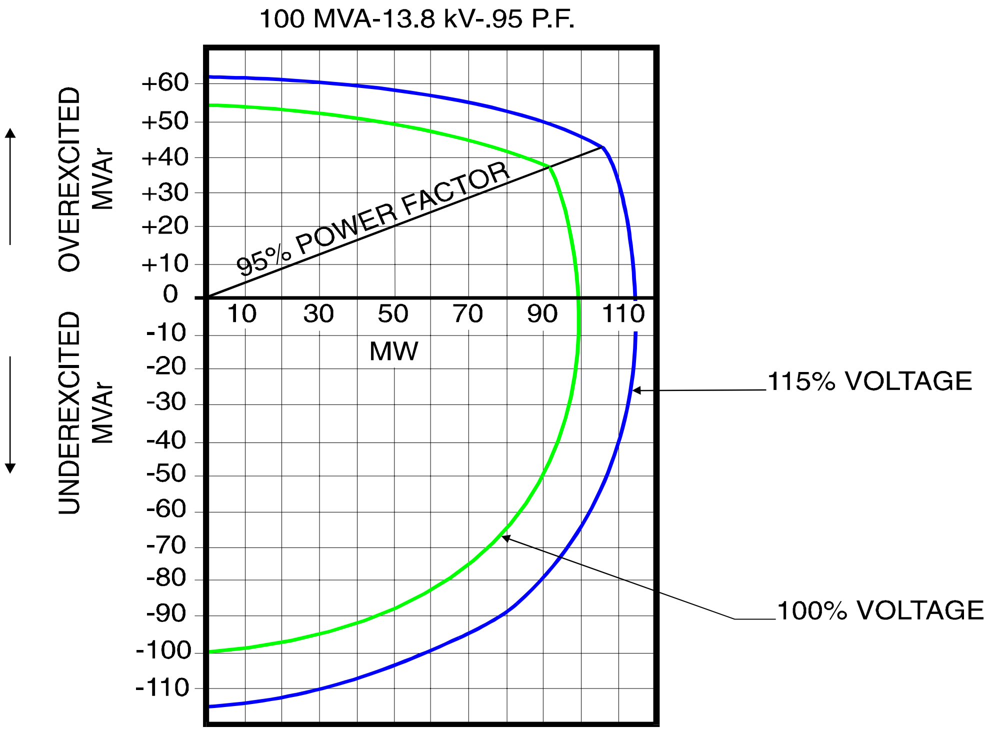


**Figure A-4**
**Actual Hydro Unit Reactive Capability Curve**

Also note there are two capability curves given in Figure A-4. One curve is for rated system voltage and the other is for voltages 15% higher. The power capability limits of a generator are mostly thermal related limits. If the system voltage is raised, the current is lowered and the power capability can be extended.

## Constraints on the Capability Curve

A generator's reactive capability curve is what a generator is physically capable of producing. Unfortunately the power system the generator is attached to, and the auxiliary equipment within the plant itself, often restrict the generator to operating within only a portion of its capability curve.

The shaded region of Figure A-5 illustrates how a generator may be restricted to only a portion of its capability curve. For example, operation in the upper or lagging portion of the curve may be restricted due to high auxiliary bus voltages within the plant. Operation in the lower or leading portion of the curve may be restricted due to unit stability problems. The actual capability of a generator can only be determined by testing the generator to determine what the reactive limits are. Many utilities have generator reactive capability test programs in place to ensure they know the true reactive capabilities of their generators.

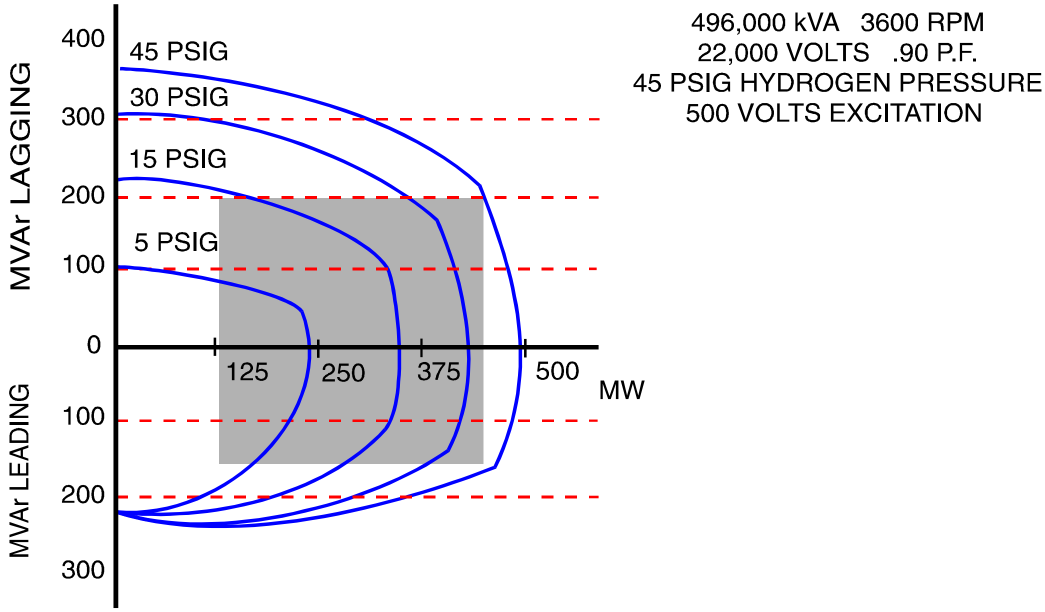


**Figure A-5**
**Reactive Production Limitations**

## Synchronous Condensers

A synchronous condenser is very similar to a synchronous generator with the exception that it is not capable of producing any active power. Synchronous condensers produce only reactive power. Synchronous condensers do not need a prime mover as they are operated as a synchronous motor. The power system supplies the active power to turn the rotor. An excitation system is used to control the amount of MVAr produced by the synchronous condenser.

Synchronous condensers are a very expensive source of reactive power and are seldom used in modern power systems. Manitoba Hydro is one of the few utilities in NERC that has new installations of synchronous condensers.

Some types of generating units (typically hydro) can be used in a synchronous condenser mode. For example, in light load conditions utilities in the Pacific Northwest may switch hydro generators from a generating to a motoring mode and then use the generator excitation systems to absorb reactive power. Steam units are rarely operated as synchronous condensers, although there are a few exceptions.

# B
# VOLTAGE CONTROL WITH TRANSMISSION EQUIPMENT

This section reviews the purpose and operation of equipment used to control system voltage and describes how a system operator uses this equipment.

## Use of Capacitors and Reactors

The primary sources of voltage control are the system generators. Capacitors and reactors are an alternate, versatile method of voltage control. Capacitors and reactors are not as expensive as generators, and are easier to construct and locate in the power system. Capacitors and reactors can be designed to be a permanent part of the system (fixed, not switchable) or be switched in and out-of-service via circuit breakers or circuit switchers.

### *Capacitors*

Capacitors are viewed as sources of reactive power. Capacitors can be connected to the power system in either a shunt or series connection. Shunt capacitors are used to supply reactive power to the system. Series capacitors are used to reduce the impedance of the path in which they are inserted.

#### Shunt Capacitors

Shunt capacitors are a source of MVAr that are installed in close proximity to the point they are needed. When a shunt capacitor is switched in the local voltage will rise. Shunt capacitor switching is often used to control normal daily fluctuations in system voltage levels due to load changes.

Shunt capacitors are installed in various power system locations including:

Transmission substations to help supply the reactive power needs of the bulk power system.

Distribution substations and large customer locations to supply the reactive power needs of the customer loads.

#### Voltage Squared Output Relationship

The reactive power output of a shunt capacitor bank is dependent on the voltage of the system it is connected to. For example, if a 25 MVAr shunt capacitor normally rated at 115 kV is operated at a 5% low voltage (109 kV) the output of the capacitor will be 90% (.95 x .95) of rated, or 22.5 MVAr.

### Series Capacitors

Series capacitors are installed in transmission lines to reduce the line's natural inductive reactance. The reactance of a series capacitor is out-of-phase with a transmission line's inductive reactance. The series capacitor reactance subtracts from the line's inductive reactance, reducing the overall line reactance.

If the line's reactance is reduced, its power transfer capability can be increased. Series capacitors increase the power transfer capability of the transmission system.

### Percent Series Compensation

The % series compensation of a transmission line is a method of stating the amount of series capacitors used in the line.

### Self Regulating

Unlike shunt capacitors, whose output decreases when it is most needed, series capacitors are "self-regulating". The term self-regulating means that a series capacitor will adjust its performance to match the needs of the system. When current passes through a series capacitor reactive power is produced by the capacitor and made available to the system. The amount of reactive power produced is proportional to the level of current flow.

When a series capacitor is needed the most, during heavy power and current flows, it produces more reactive power. During light loads on the system, when the series capacitor's MVAr is less important, the MVAr output naturally reduces. Series capacitors regulate themselves.

## *Reactors*

Reactors can be viewed as absorbers or sinks of reactive power. Reactors can be connected to the power system in either a shunt or series connection. Shunt reactors are used to absorb reactive power from the system. Series reactors are used to increase the reactance of the path in which they are inserted.

### Shunt Reactors

Shunt reactor banks are used to absorb excessive reactive power from the power system and thereby reduce system voltages. When high voltage transmission lines are built, fixed and switchable reactor banks are often installed to help reduce the overvoltages caused by lightly loaded high voltage lines. The switchable reactor banks are typically under SCADA control. Switched reactor banks are often found on transformer tertiary windings. These reactor banks are remotely switched in and out-of-service to control high voltages.

### Series Reactors

Reactors can also be installed in series. Series reactor installations are not uncommon in the distribution system or within older power plants. Series reactors add inductive reactance to a path thereby increasing the overall path impedance. The primary use of series reactors is to limit fault current. Fault current is limited due to the increase in the path's impedance. Series reactors can also be installed in the transmission system to help reduce power oscillations between generators.

## Use of Transformers

Transformers in which the number of turns in a winding can be adjusted under load are a valuable tool for voltage control. The construction and operation of tap changing transformers are described in this section.

### *Tap Changing Transformers*

#### Off-Load Tap Changing (OLTC)

Power transformers are often equipped with a means to vary the size of the primary or secondary windings. If the winding size can be controlled, the voltage induced in the winding can (usually) also be controlled. The ability to control the winding size gives the transformer operator a range of control over the primary and secondary output voltages of the transformer.

Most power transformers include tap changers that can only be adjusted when the transformer is out-of-service. These taps are called "off-load tap changers" or OLTCs. Off-load tap changers are mechanical linkages within the primary or secondary windings of the transformer. The linkages are designed to be adjusted to change the transformer winding turns ratio. These linkages can only be adjusted when the transformer current flow has been completely interrupted. A typical power transformer may have five tap positions (labeled A - E or 1 - 5) within the off-load tap changer. Under Load Tap Changing (ULTC). Many new ULTCs are 33 position devices. These ULTCs will have a neutral position, 16 raise and 16 lower taps. The voltage control range is typically ±10% so each tap is good for a 5/8% voltage adjustment. The advantage of a 33 position ULTC over a 17 position is better (more exact) voltage control.

#### Under Load Tap Changing (ULTC)

Some power transformers possess a more powerful means for changing tap positions. Under load tap changing or ULTC equipped transformers are designed to change tap positions while the transformer is carrying load current. ULTCs can be operated in either a manual or an automatic mode of operation. When in manual mode, tap positions can be adjusted via selector switches installed in the ULTC control cabinet. These selector switches can also be operated via SCADA if the utility has installed the necessary equipment. While in manual mode the ULTC does not automatically respond to voltage changes in the system. An operator must intervene to adjust the tap positions.

An ULTC can also be placed in an automatic mode of operation. When in automatic mode the ULTC automatically responds to system conditions and adjusts its tap positions without operator intervention. For example a ULTC may be designed to keep a constant secondary voltage. When the secondary voltage deviates from the intended point the ULTC will automatically adjust the tap position in an attempt to return the secondary voltage to the set-point. Whether the ULTC is successful in the attempt to control the secondary voltage depends on several factors including the room left to adjust taps. A ULTC can only make a voltage adjustment if it has taps available to adjust. The ULTC may go to full boost or full buck and still be unable to control the voltage.

### *Tap Changing and Reactive Power*

Tap changers control the voltage of a transformer's winding by adjusting the number of turns in the winding. When the turns ratio is adjusted the flow of reactive power across the transformer is normally adjusted. Changes in reactive power flow are necessary to accomplish the intended voltage change.

### *Use of Static VAr Compensators (SVC)*

#### Components of an SVC

A static VAr compensator (SVC) is similar to a synchronous condenser in that it is also used to supply or absorb reactive power. However in an SVC there are no rotating parts, every element is static. SVCs are composed of shunt reactors and shunt capacitors. High speed electronic switching equipment (thyristor switches) are used to adjust the amount of reactors or capacitors in-service at any one time. SVCs have the equivalent of automatic voltage regulator systems to set and maintain a target voltage level.

### *Use of the Static Synchronous Compensator (STATCOM)*

The STATCOM (Figure B-1) is an "electronic generator" of dynamic reactive power that is connected in shunt with the substation bus/transmission line and designed to provide smooth, continuous voltage regulation, prevent voltage collapse, improve transient stability and damp power oscillations.

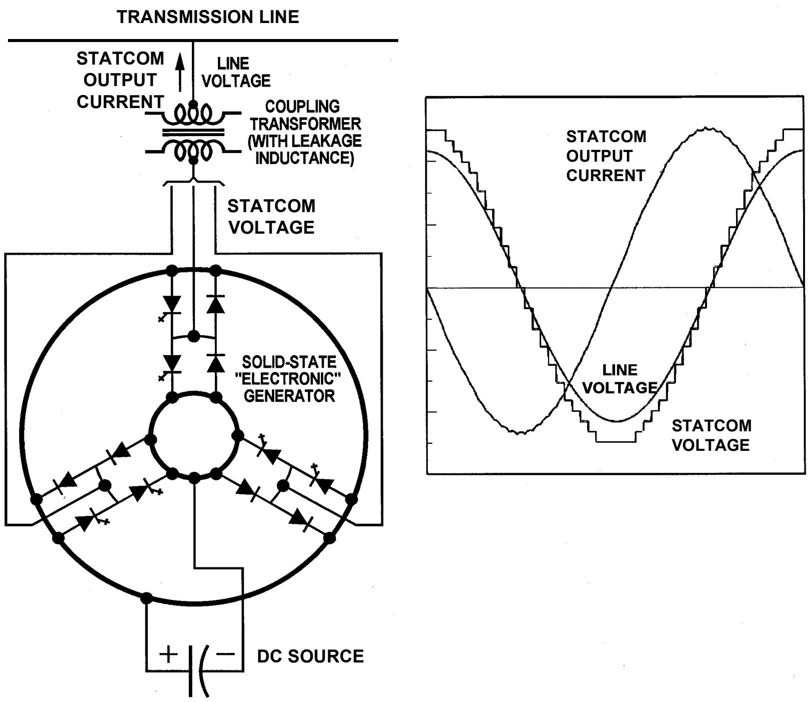


**Figure B-1**
**The STATCOM is a solid-state synchronous voltage source that internally generates or absorbs reactive power**

The STATCOM can be utilized as a basic building block in any of the comprehensive set of ac power flow controllers to address the complete range of transmission network compensation requirements: shunt, series, series/shunt and back-to-back for an asynchronous intertie. The guiding objective behind this approach is to eliminate the problem of "stranded" assets by means of configuring and/or expanding existing equipment to meet new requirements imposed by system operation or load or generation changes. A STATCOM thus never needs to become a "stranded" asset.

The STATCOM employs a static, self-commutated power converter operated as a shunt connected static var compensator whose capacitive or inductive output current can be controlled independent of the ac system voltage over a wide range of line voltage. Unlike conventional Static Var Compensators (SVCs), the STATCOM does not rely on ac passive capacitors and reactors to generate or absorb reactive power. The static converter-based approach of exchanging reactive power with the transmission system is accountable for the superiority of STATCOM performance versus that of SVCs in line voltage support applications.

A STATCOM provides an adjustable ac voltage source for this purpose in the form of a large electronic dc-to-ac inverter with the dc-side terminal voltage supported by a capacitor that ideally carries no current. Figure B-2 shows the V-I characteristics of the STATCOM. In contrast to the conventional thyristor-controlled compensators, the STATCOM is able to provide rated reactive current under reduced voltage conditions. This ability to produce significantly more VArs at low voltage means that the STATCOM offers better voltage support and improved transient stability margin. This advantage offers significant benefits for an asynchronous intertie by providing the capability to maintain critical voltage regulation at each AC grid terminal point. It also has transient overload capability to increase both the capacitive and inductive compensation for several cycles. Note that the SVC has no capability to increase the rated capacitive compensation without switching in additional capacitor banks.

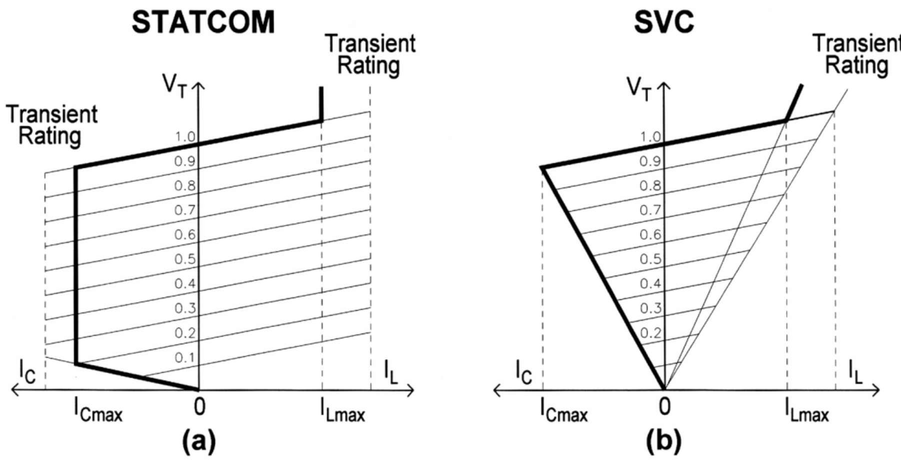


**Figure B-2**
**V-I Characteristics of the STATCOM and SVC**

The dynamic capabilities of the STATCOM, which does not utilize large passive ac reactive components, provides very fast response and greater stability to system variations in impedances. This enables the STATCOM to damp disturbances and system oscillations that may result, for instance, from switching nearby compensation banks.

### *Line Switching for Voltage Control*

High voltage transmission lines appear to the power system as shunt capacitors when they are lightly loaded. During light load periods of the year many utilities are forced to take high voltage lines out-of-service to reduce system voltage levels. For example, a utility may remove several long 345 kV lines each spring evening and return the lines to service when the load picks up the next morning.

The line’s that are removed from service will be those that contribute significant reactive power and whose removal will not significantly reduce system security. Rules of thumb for charging from high voltage lines are approximately .4 MVAr per mile for 230 kV, 0.8 MVAr per mile for 345 kV and 2.2 MVAr per mile for 500 kV lines. If a utility has a choice between removing either a 100 mile long 230 kV or 100 mile long 500 kV line, the 500 kV line removal would normally have more impact on system voltage.

## Role of the System Operator

The system operator exercises a great deal of control over power system voltages. This control is largely limited to long term (sustained) voltage deviations. A system operator cannot typically respond fast enough to have any impact on short term or transient voltage deviations.

### *Monitoring Voltage*

The following are indications that voltage deviations exist that may require system operator response. These indications may be observed on the SCADA system or via reports from field personnel and other system operators.

- Key substations or specific areas of the power system have lower than normal voltages.
- Reactive power flows are higher or lower than normal or flowing in unusual directions.
- ULTCs are at abnormal positions, such as full boost or full buck.
- Generator reactive power flows are higher or lower than normal. Generators may be operating near reactive output limits.
- The power system may enter a period of voltage oscillations. This could be the result of reactive power shortages.

### *Actions to Raise Voltage*

Among the options available to a system operator to respond to low voltage problems on the power system are:

- Ensuring that all available equipment (lines, transformers, etc.) are in-service. For example, a transmission line may have been removed previously for high voltage control or for maintenance.
- Removing switchable shunt reactors.
- Inserting switchable shunt and series capacitors.
- Adjusting taps on ULTCs.
- Requesting all available support from area generating units and neighboring systems. (Request that the units produce more MVAr.)
- Adjusting the output of area generators by changing the mix of generation. For example, reducing active power generation at one power plant and increasing it on another to change system power flows. This action may involve cost to the utility as more expensive generation may have to be brought on-line.
- Requesting that power sales or purchases be cut to lower transfers through a low voltage area.
- Initiating load shedding schemes.

## *Maintaining Reactive Reserves*

In the same manner as spare MW capability is held in reserve to respond to unforeseen events, spare MVAr capability should also be held in reserve to respond to unforeseen events.

Reactive reserves are spare reactive capability available to assist with system voltage control. Reactive reserves are composed of both reactive supply (lagging reactive) and reactive absorption (leading reactive) capability. Reactive reserves include spare shunt capacitors, shunt reactors, SVCs, synchronous condensers, and generators.

### Dynamic Reactive Reserves

Dynamic reactive reserves are reactive reserves that can be used to rapidly respond to system voltage deviations. (Rapidly means within a few cycles.)  Manually controlled shunt capacitors or ULTCs are not dynamic reactive reserves since their control is subject to slow human actions. Most automatic controlled shunt capacitors do not qualify as dynamic reactive reserves as their control systems often limit their response.

Three types of equipment that do fit the definition of dynamic reactive reserves are static VAr compensators (SVC), synchronous condensers, and synchronous generators. This section will concentrate on the use of synchronous generators as dynamic reactive reserves.

The voltage control capabilities of a generator are a function of the reactive range (both MVAr production and absorption) of the generator and the speed of the excitation system. Modern generators have very rapid excitation systems. The combination of a fast excitation system and a large reactive range creates a powerful voltage control device.

To respond to rapid unexpected system voltage deviations a utility needs to carry sufficient reactive reserves in their better responding reactive resources. For example, if a rapid voltage drop or rise occurs, a utility will often do a better job of correcting the voltage deviation if they are carrying reactive reserves in their generators.

To ensure sufficient response to system voltage changes it is a wise practice to establish limits to the amount of reactive reserves available from system generators. For example, a utility may specify that all generators will have available at least ½ of their lagging and ½ of their leading reactive capability to respond to unforeseen events. To ensure acceptable levels of reactive reserves are kept in the system generators, a system operator may have to switch shunt reactors or shunt capacitors. For example, assume load is rising and the generators are moving well up into their lagging region. By switching in shunt capacitors a system operator can relieve the MVAr supply obligations of the generators and allow an increase to their reactive reserves

# C
# EXCERPTS FROM NERC REFERENCE DOCUMENT INTERCONNECTED OPERATIONS SERVICES, MARCH 28-29, 2001

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

## Excerpts from

# Reference Document

# Interconnected Operations Services

Prepared by the
Interconnected Operations Services Subcommittee

Approved by the Operating Committee:
March 28–29, 2001

Only sections of The Reference Document are inserted here. For the full text of this document, go to www.nerc.com

# Table of Contents

Note that the lighter colored text has been deleted from this document. See the note on the title page for the source of the full text.

# Section 1. Overview

## 1.1 Scope and Purpose

This Interconnected Operations Services (IOS) Reference Document was developed by the Interconnected Operations Services Subcommittee in response to a directive from the NERC Operating Committee in November 2000. This IOS Reference Document:

- Defines and describes the characteristics of INTERCONNECTED OPERATIONS SERVICES (IOS)
- Describes the necessity of IOS as 'reliability building blocks' provided by generators (and sometimes loads) for the purpose of maintaining BULK ELECTRIC SYSTEM reliability.
- Explains the relationship between OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS.
- Provides sample standards that could be used to define the possible obligations of OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS
- Describes sample methods for performance measurement in the provision of IOS
- Describes sample methods for the certification of IOS RESOURCES.

# Section 2. Description of IOS

## 2.1 Generation and Demand Balancing IOS

### Control Area Obligations

In their simplest form, generation and demand balancing IOS are capacity and the ability to raise and lower output or demand in response to control signals or instructions under normal and post-contingency conditions. Generators, controllable loads, or storage devices may provide these capabilities. Energy may also be delivered by a resource as a byproduct of providing the balancing capability.

The OPERATING AUTHORITY aggregates and deploys resources providing these services to meet the CONTROL AREA generation and demand balancing obligations, defined by control performance standards in NERC Operating Policy 1. These resources may supply a diverse mix of IOS, since balancing occurs in different time horizons and under both pre- and post-contingency conditions.

Section E of NERC Operating Policy 1 requires that a CONTROL AREA meet the following criteria:

- **Control Performance Standard 1 (CPS1).** Over a year, the average of the clock-minute averages of a CONTROL AREA's ACE divided by –10B (B is the CONTROL AREA frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION'S frequency error shall be less than a specific limit;
- **Control Performance Standard 2 (CPS2).** The ten-minute average ACE must be within a specific limit ($L_{10}$) at least 90% of the time within each month; and
- **Disturbance Control Standard (DCS).** For reportable disturbances, the ACE must return either to zero or to its pre-disturbance level within a specified disturbance recovery time (defined in IOS Reference Document as $T_{DCS}$[1] minutes) following the start of a disturbance.

### Operating Reserves

Policy 1 also requires a CONTROL AREA to provide a level of OPERATING RESERVES sufficient to account for such factors as forecasting errors, generation and transmission equipment unavailability, system equipment forced outage rates, maintenance schedules, regulating requirements, and load diversity. Policy 1 states that OPERATING RESERVEs consist of REGULATION and CONTINGENCY RESERVES, and that OPERATING RESERVES can be used for the reasons listed above. OPERATING RESERVES may be comprised of: (1) available capacity from resources providing REGULATION and LOAD FOLLOWING services, (2) CONTINGENCY RESERVES, (3) available FREQUENCY RESPONSE capacity, and (4) load-serving reserves or backup supply.

Load-serving reserves are the responsibility of a LOAD-SERVING ENTITY. They are designed to account for errors in forecasting, anticipated and unanticipated generation/resource and transmission outages, and maintenance schedules that impact the delivery of energy to the LOAD-SERVING ENTITY. These reserves support the reliability of individual LOAD-SERVING ENTITIES, rather than the interconnected BULK ELECTRIC SYSTEMS. As a result, they are not an IOS and are not addressed in this IOS Reference Document.

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[1] The disturbance recovery time is defined in Policy 10 as a variable $T_{DCS}$ to recognize that the specified recovery time stated in Policy 1 may change.

## Overview of Generation and Demand Balancing IOS

Table 1 summarizes the IOS necessary to provide generation and demand balancing services and shows the reliability objective associated with each.

**Table 1 – Overview of Generation and Demand Balancing Resources**

| IOS | | Reliability Objective | |
|---|---|---|---|
| | | **Normal operating state** | **Post-contingency** |
| REGULATION | | Follow minute-to-minute differences between generation and demand. | |
| *LOAD FOLLOWING* | | *Follow generation and demand imbalances occurring within a scheduling period.* | |
| *FREQUENCY RESPONSE*[2] | | | *Arrest deviation from scheduled frequency.* |
| CONTINGENCY RESERVES | *SPINNING* | | *Restore generation and demand balance, usually after a contingency.* |
| | SUPPLEMENTAL | | Restore generation and demand balance after a contingency |

[2] In this IOS Reference Document, FREQUENCY RESPONSE is treated as an INTERCONNECTION security function, rather than a generation and demand balancing function. It is shown in Table 2 and Figure 2 only for the purpose of showing the deployment times relative to those of the generation and demand balancing IOS.

Figure 2 compares the use and deployment period of the load and generation balancing services.

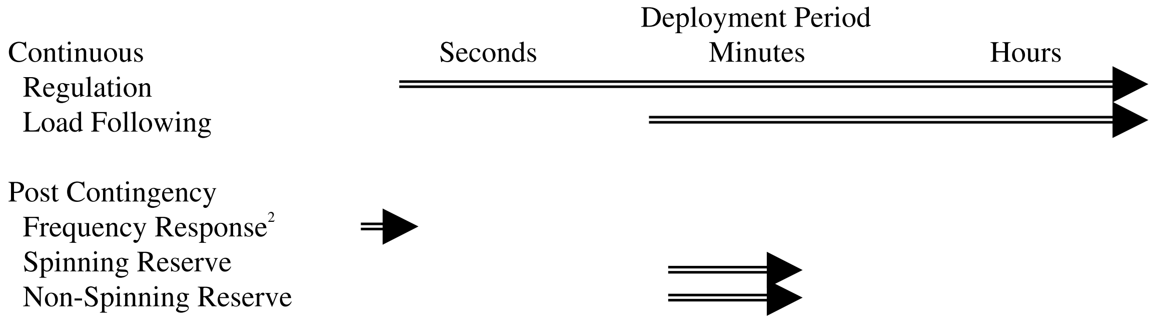


**Figure 2 – Deployment Period for Load and Generation Balancing Services**

## Description of REGULATION AND LOAD FOLLOWING

REGULATION and LOAD FOLLOWING require similar capabilities and are addressed together in this IOS Reference Document. A major difference is that LOAD FOLLOWING resources are deployed over a longer time horizon and over a generally wider range of output than resources providing REGULATION. The LOAD FOLLOWING burden imposed by individual loads tends to be highly correlated while the REGULATION burden tends to be largely uncorrelated.

REGULATION provides for generation and demand balancing in a time frame of minutes. The CONTROL AREA continuously determines the required changes (up and down) to the real power output of regulating resources to correct ACE to within CPS bounds.

*LOAD FOLLOWING addresses longer-term changes in demand within scheduling periods. LOAD FOLLOWING resources, under automatic or manual control, chase (and to an extent anticipate) the longer term variations within a scheduling period. Figure 3 distinguishes the time horizons of REGULATION AND LOAD FOLLOWING IOS.*

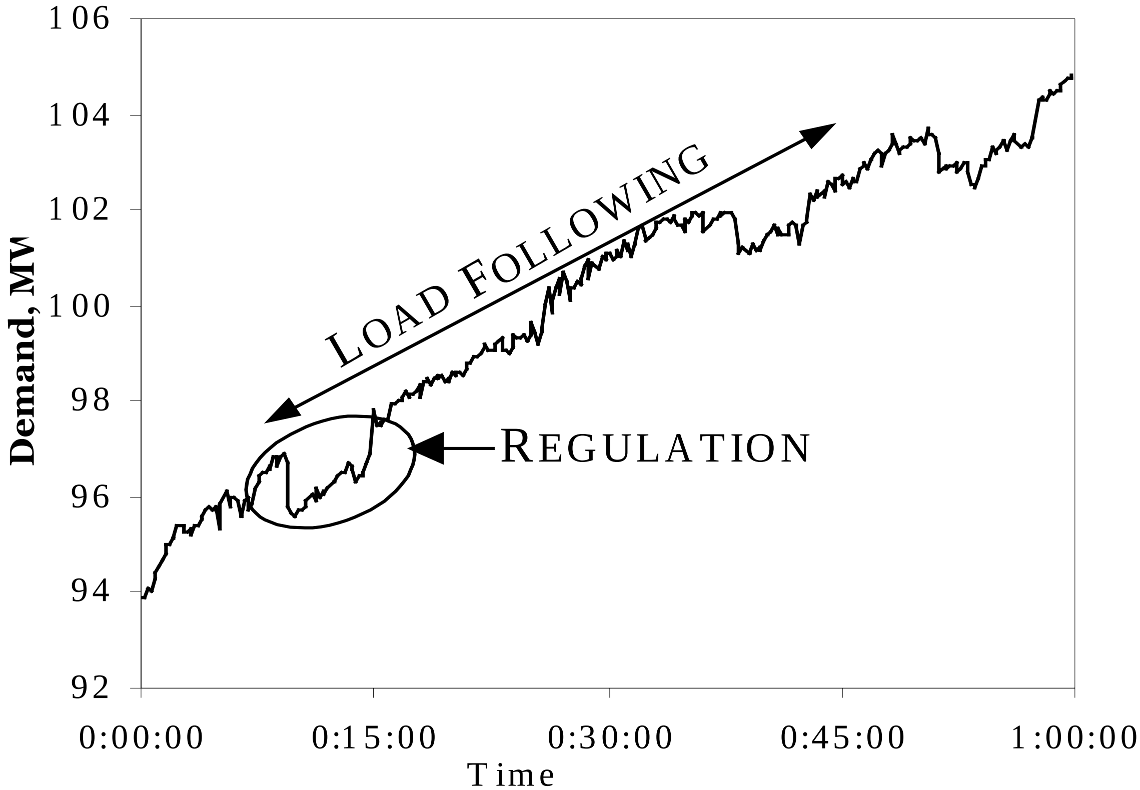


**Figure 3 – REGULATION and LOAD FOLLOWING**

## Description of Contingency Reserve

In addition to committing and controlling resources to ensure continuous balance between generation and demand, NERC Policy 1 requires an OPERATING AUTHORITY to return generation and demand to a balanced state (or at least to the same level of imbalance as the pre-contingency state) within ten minutes following a contingency. CONTINGENCY RESERVE provides standby capability to meet this requirement.

Following a contingency, FREQUENCY RESPONSE will immediately begin to arrest the frequency deviation across the INTERCONNECTION. Within the affected CONTROL AREA, resources providing REGULATION will begin to adjust outputs within seconds in response to signals from the CONTROL AREA's AGC. In addition, the OPERATING AUTHORITY may deploy, if necessary, CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. These reserves are used to restore the pre-contingency generation and demand balance, FREQUENCY RESPONSE capacity, and REGULATION capacity. In all cases, the CONTINGENCY RESERVE must be sufficiently activated so that within $T_{DCS}$ (or less) the pre-contingency generation/demand balance and FREQUENCY RESPONSE capacity are restored. Delivery of these reserves must be sustainable for the minimum reserve deployment period.

The time line below graphically shows the operating relationship between FREQUENCY RESPONSE, CONTINGENCY RESERVE and an individual LOAD-SERVING ENTITY'S reserve or backup supply.

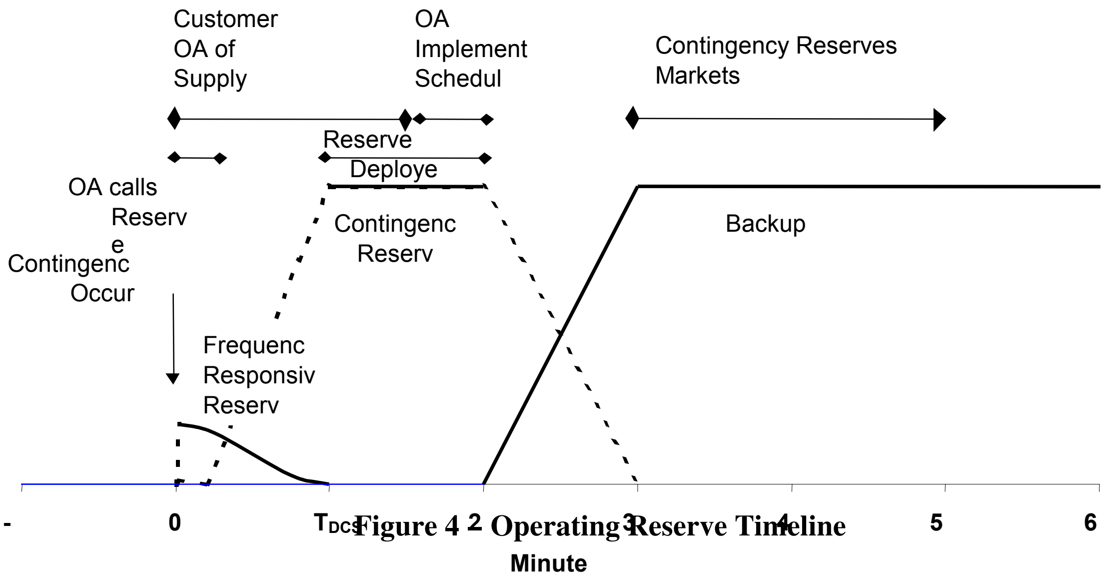


**Figure 4 Operating Reserve Timeline**

Coordinated post-contingency operating plans are necessary to ensure CONTROL AREAs are able to deploy and restore CONTINGENCY RESERVE in a timely manner. These plans must outline the reserve obligations of CONTROL AREAS, OPERATING AUTHORITIES, and LOAD-SERVING ENTITIES. These arrangements should delineate when and how schedules will be curtailed, which CONTROL AREA or OPERATING AUTHORITY is responsible to deploy CONTINGENCY RESERVE, and when and how replacement schedules, if any, will be implemented.

## Transmission Losses

Although the previous discussion focused on the mismatch between generation and demand due to randomly varying loads as well as control and scheduling errors, the losses associated with use of the transmission system must also be recognized. Real power losses are actually another type of demand and, if not compensated for, can cause a deficiency in reserves and system frequency degradation, thus threatening system reliability.

All electrical flows impact system losses. This includes transmission customer uses, native load uses, parallel flows, and other uses. All scheduled users of the transmission system are responsible for providing losses associated with their use of the system. The CONTROL AREA is responsible to balance total system demand, including losses.

The difference in real-time between actual system losses and resources scheduled to supply system losses is provided by REGULATION and LOAD FOLLOWING. For this reason, the IOS Reference Document does not treat losses as a separate IOS. Instead losses are handled in the market, through scheduling processes, in accordance with transmission tariffs and contracts. Any differences between scheduled and actual losses are addressed through REGULATION and LOAD FOLLOWING, or possibly through ENERGY IMBALANCE measures, if a transmission customer is delivering energy to compensate for losses.

### Energy Imbalance

Energy and scheduling imbalances are measures of how well a transmission customer is meeting its balancing obligations at a specific point or points on the system. Such imbalances are calculated as the difference between actual and scheduled energy at a point of receipt or point of delivery over a scheduling period.

The provision of generation and demand balancing in a pre-contingency state for a transmission customer is done through the use of scheduled delivery of resources to serve the transmission customer's load, along with the provision of REGULATION and LOAD FOLLOWING.

Although existing transmission tariffs may treat energy imbalance as a service, the IOS Reference Document considers energy imbalance, including scheduling imbalances with generators, as energy mismatch measurements. Energy imbalance is a measure of historical performance averaged over a time period. IOS are *capabilities* that are deployed in the present & future to meet reliability objectives. Both energy imbalance and IOS can be measured, and can have reliability criteria and economic terms. However, energy imbalance only describes past performance, while IOS are services that may be deployed now and in the future for reliability purposes.

## 2.2 Bulk Electric System Security IOS

System security refers to the ability of BULK ELECTRIC SYSTEMS to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Two fundamental capabilities needed to maintain BULK ELECTRIC SYSTEM security are the ability to[3]:

1. Maintain system voltages within limits to maintain INTERCONNECTION reliability under normal and emergency conditions. This is accomplished by coordinating the following minimum components of transmission system voltage control:
   - Load power factor correction;
   - Transmission reactive compensation (capacitors, reactors, static var compensators, etc.);
   - Generator interconnection requirements with the transmission provider (relay and control, power factor, voltage, etc.);
   - CONTROL AREA coordination; and
   - REACTIVE POWER SUPPLY FROM GENERATION SOURCES (IOS)
2. Automatically and rapidly arrest frequency excursions due to contingencies on BULK ELECTRIC SYSTEMS. This capability constitutes the FREQUENCY RESPONSE IOS.

### Reactive Power Supply from Generation Sources

REACTIVE POWER SUPPLY FROM GENERATION SOURCES comprises the following essential capabilities from generators (and possibly some loads): reactive capacity, reactive energy, dynamic and fast-acting responsiveness through the provision and operation of an Automatic Voltage Regulator (AVR), and the ability to follow a voltage schedule. REACTIVE POWER SUPPLY FROM GENERATION SOURCES is used by

3 Refer to Operating Policy 2 B and Planning Policy I D for Control Area standards related to voltage control.

the OPERATING AUTHORITY to maintain system voltages within established limits, under both pre- and post-contingency conditions, and thereby avoid voltage instability or system collapse.

### Interconnection Requirements - Reactive

In addition to the use of this generation-based IOS, the OPERATING AUTHORITY maintains transmission security through the coordinated use of static reactive supply devices throughout the system, and may develop and impose reactive criteria on LOAD-SERVING ENTITIES. Requirements for the non-generator components are addressed in other NERC, Regional Reliability Council, and local standards and interconnection requirements.

As an example, minimum interconnection requirements include NERC Planning Standard III C S1, which states: "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.'' The intent is that there be no supplementary excitation control (reactive power or power factor control) that limits emergency reactive power output to less than reactive power capability.

Generator power factor and voltage regulation standards can be a condition of interconnection to satisfy area or local system voltage conditions. Voltage regulating capacity and capabilities that are provided to meet minimum interconnection requirements do not imply that those generators are qualified IOS SUPPLIERS.

### Frequency Response

FREQUENCY RESPONSE is the capability to change, with no manual intervention, an IOS RESOURCE's real power output in direct response to a deviation from scheduled frequency.

The need for FREQUENCY RESPONSE extends beyond the boundaries of a CONTROL AREA to meet the reliability needs of the INTERCONNECTION. Hence it is aligned with a transmission security objective rather than the load and generation balancing objective. FREQUENCY RESPONSE is not required to meet the CONTROL AREA needs related to DCS. CONTINGENCY RESERVE is used for that purpose.

FREQUENCY RESPONSE is achieved through an immediate governor response to a significant change in INTERCONNECTION frequency. The cumulative effect of the governor response within the INTERCONNECTION provides an INTERCONNECTION-wide response to a frequency deviation (i.e., all CONTROL AREAS will "see'' a frequency change and contribute their frequency response in proportion to the frequency change). This governor action arrests the frequency deviation and allows other slower responding control actions to effectively restore system frequency and affected CONTROL AREA's ACE.

## 2.3 Emergency Preparedness

Emergency preparedness refers to the measures taken to prepare for the rare occasions when all or a major portion of a BULK ELECTRIC SYSTEM or INTERCONNECTION is forced out of service. When this occurs, the capability must exist to restore normal operations as quickly as possible. This is called system restoration. System restoration requires:

- SYSTEM BLACK START CAPABILITY – Generating units that can start themselves without an external electricity source and can then energize transmission lines and restart other generating units;

- Non-black start generating units that can quickly return to service after offsite power has been restored to the station and can then participate in further restoration efforts;
- Transmission system equipment, controls, and communications (including ones that can operate without grid power), and field personnel to monitor and restore the electrical system after a blackout;
- System control equipment and communications (including ones that can operate without grid power); and
- Personnel to plan for and direct the restoration operations after such a blackout.

The IOS Reference Document deals only with the first of these five aspects of system restoration, as it is a critical reliability services that must be provided by generation resources. Other NERC Planning and Operating Standards address other elements of this service. NERC Planning Standards 4A, System Black Start Capability, state that: "Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration.'' These initiating generators are referred to as SYSTEM BLACK START CAPABILITY.

NERC Operating Policy 6 D, Operations Planning – System Restoration, requires: Each system, CONTROL AREA, and Region shall develop and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. For further reference, see Policy 5 E, Emergency Operations-System Restoration.

# Section 3. Sample IOS Standards

## 3.1 Sample General Requirements

### Introduction

Section 3.1 provides a sample of general requirements that may be applicable for all IOS. These sample general requirements establish a framework of responsibilities for:

- Development of IOS specifications and metrics for certification and performance evaluation.
- The provision of IOS, including planning, aggregation, and deployment.
- Monitoring and verification of IOS.

Specific sample standards for each IOS are provided in the remaining parts of Section 3. The sample standards throughout Section 3 are grouped into two main subheadings according to the type of entity to which the standards may apply: OPERATING AUTHORITY or IOS SUPPLIER.

*The sample standards in the IOS Reference Document stipulate that the required amounts of each IOS are contingent upon the characteristics of the regional or local BULK ELECTRIC SYSTEMS. Such specific regional or local requirements should be developed through a process that is a) open to and inclusive of all market participants, and b) in accordance with the prevailing regional processes for standards development.*

*The sample IOS SUPPLIER requirements are intended to apply to all IOS RESOURCES regardless of ownership.*

### Sample General Requirements – Operating Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Provision of IOS.** The OPERATING AUTHORITY shall assure sufficient IOS are arranged, provided, and deployed to meet NERC, Regional Reliability Council, and local planning and operating standards.

2. **Specify IOS Requirements.** The OPERATING AUTHORITY shall determine IOS requirements through an open and inclusive process that is consistent with regulatory requirements, is coordinated at a regional level, includes market stakeholders, and allows for dispute resolution. Regional and local IOS requirements include but are not limited to:

   **2.1.** The quantity, response time, duration, location and other criteria for each IOS as necessary to meet NERC, Regional Reliability Council, and local planning and operating standards.

**2.2.** Written procedures for the arrangement, provision, and deployment of IOS.

**2.3.** Metering requirements, consistent with established industry practices, for IOS RESOURCES.

**2.4.** Voice and data communication requirements associated with provision and delivery of IOS.

**2.5.** Transmission service requirements for delivery of each IOS.

**3.** **Changing System Conditions.** IOS requirements and procedures shall be adapted as necessary to maintain system reliability in response to current or expected system conditions.

**4.** **Publication of IOS Requirements.** The OPERATING AUTHORITY shall maintain publicly available documents specifying IOS requirements and procedures.

**5.** **Performance Verification.** The OPERATING AUTHORITY shall monitor the actual performance of IOS RESOURCES under normal and/or disturbance conditions to verify the IOS RESOURCE meets published performance criteria.

## Sample General Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

**7.** **IOS RESOURCE Capabilities.** An IOS SUPPLIER shall provide IOS RESOURCES which are:

**7.1.** Able to deliver the stated IOS capabilities to the BULK ELECTRIC SYSTEM.

**7.2.** Responsive to the instructions and controls of the OPERATING AUTHORITY, as specified for each IOS and consistent with previously agreed upon terms and conditions between the IOS SUPPLIER and OPERATING AUTHORITY.

**8.** **IOS RESOURCE Certification**. The capabilities of IOS RESOURCES shall be certified according to the defined minimum criteria. (See IOS Reference Document Section 5 for certification criteria.)

**9.** **Metering.** An IOS SUPPLIER shall provide and maintain metering to measure IOS capabilities and performance, as specified by published IOS requirements.

**10.** **Voice and Data Communications.** An IOS SUPPLIER shall provide and maintain voice and data communications, as specified by published IOS requirements, to enable:

**10.1.** IOS RESOURCES to respond to the instructions or controls of the OPERATING AUTHORITY.

**10.2.** OPERATING AUTHORITIES to monitor the capabilities and verify the performance of IOS RESOURCES.

11. **Provision of IOS.** An IOS SUPPLIER shall, as soon as practicable, notify the OPERATING AUTHORITY of any changes in the capability to provide the service or meet stated obligations.

12. **Performance Verification.** Upon request, an IOS SUPPLIER shall provide information to the OPERATING AUTHORITY necessary to verify performance, in accordance with published IOS requirements and procedures. All IOS SUPPLIERS, including OPERATING AUTHORITIES, which are IOS SUPPLIERS, shall maintain and provide verifiable data for certification purposes.

13. **Concurrent Commitment of IOS RESOURCES.** An IOS SUPPLIER may make concurrent commitments of an IOS RESOURCE's capability to provide IOS (for example providing recallable energy and CONTINGENCY RESERVE – SUPPLEMENTAL), if the following conditions are met:

    **13.1.** The practice is disclosed, in advance, to the OPERATING AUTHORITY(IES) involved; and

    **13.2.** The arrangements do not conflict with meeting the IOS SUPPLIER's obligations, nor the provision requirements of each concurrently committed IOS. For example, the same capacity for CONTINGENCY RESERVE may not be concurrently used for REGULATION.

## 3.2 Sample REGULATION and LOAD FOLLOWING Requirements

### Sample Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The OPERATING AUTHORITY shall determine the IOS requirements for REGULATION and LOAD FOLLOWING in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response capabilities of IOS RESOURCES.

2. **Provision.** The OPERATING AUTHORITY shall assure sufficient REGULATION and LOAD FOLLOWING capabilities are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local planning and operating standards.

3. **Deployment.** The OPERATING AUTHORITY shall direct the current and future loading of the portion of IOS RESOURCES providing REGULATION or LOAD FOLLOWING. Loading refers to the energy delivery of the IOS RESOURCE, within the operating constraints committed by the IOS SUPPLIER.

4. **IOS SUPPLIER Performance Monitoring.** The OPERATING AUTHORITY shall monitor the REGULATION and LOAD FOLLOWING performance of IOS SUPPLIERS. The OPERATING AUTHORITY shall maintain records of IOS SUPPLIER performance and data used to calculate performance.

### Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

**Declaration of REGULATION Response Capability.** An IOS SUPPLIER that has agreed to provide REGULATION shall declare to the OPERATING AUTHORITY the IOS RESOURCE's:

**5.1.** Maximum and minimum outputs that define the REGULATION range of the IOS RESOURCE**.**

**5.2.** MANEUVERABILITY characteristics including ramp up and ramp down limit, minimum time between requests for control changes, and maximum and minimum acceleration.

**Declaration of LOAD FOLLOWING Response Capability.** An IOS SUPPLIER providing LOAD FOLLOWING shall declare to the OPERATING AUTHORITY the IOS RESOURCE's:

**5.3.** Maximum and minimum outputs that define the LOAD FOLLOWING range of the IOS RESOURCE.

**5.4.** The ramp rate and acceleration of the IOS RESOURCE**.**

**5.5.** The minimum time period between requests for load changes.

**REGULATION Response.** An IOS RESOURCE that is offered to provide REGULATION shall automatically change the real power output in response to the controls supplied by the OPERATING AUTHORITY, subject to the agreed upon REGULATION capabilities of the IOS RESOURCE.

**LOAD FOLLOWING Response.** An IOS RESOURCE that is offered to provide LOAD FOLLOWING shall increase or decrease its real power output in response to instructions from the OPERATING AUTHORITY, subject to the agreed upon LOAD FOLLOWING capabilities of the IOS RESOURCE.

**Metering and Communication.** An IOS SUPPLIER offering to provide REGULATION or LOAD FOLLOWING shall meet the following minimum metering and communication requirements:

**5.6.** The IOS RESOURCE shall have an OPERATING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the CONTROL AREA.

**5.7.** The IOS RESOURCE shall have an OPERATING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the OPERATING AUTHORITY and the operator controlling the IOS RESOURCE.

**5.8.** The IOS SUPPLIER shall provide to the OPERATING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE. The update frequency for REGULATION and LOAD FOLLOWING shall be in accordance with the requirements and guides in Operating Policy 1. The availability and reliability of the telecommunications shall comply with Operating Policy 7.

**REGULATION and LOAD FOLLOWING IOS RESOURCES Outside of the CONTROL AREA.** IOS SUPPLIERS providing REGULATION or LOAD FOLLOWING from IOS RESOURCES located in a CONTROL AREA other than the CONTROL AREA in which the load is physically connected, shall be controlled by a DYNAMIC TRANSFER.

## 3.3. Sample CONTINGENCY RESERVE Requirements

### Sample Requirements – Operating Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The OPERATING AUTHORITY shall determine the IOS requirements for CONTINGENCY RESERVE – SPINNING, and CONTINGENCY RESERVE – SUPPLEMENTAL in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics, allowed overshoot, and the portion of CONTINGENCY RESERVE that must be SPINNING or SUPPLEMENTAL.

2. **Provision.** The OPERATING AUTHORITY shall assure sufficient capabilities for CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **CONTINGENCY RESERVE Dispersion.** CONTINGENCY RESERVES dispersion shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

4. **Deployment of CONTINGENCY RESERVE – SPINNING AND SUPPLEMENTAL.** The OPERATING AUTHORITY shall direct the loading of IOS RESOURCES that provide CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. The OPERATING AUTHORITY shall ensure deployment capability within the required recovery time from disturbance conditions ($T_{DCS}$) specified in Operating Policy 1. The OPERATING AUTHORITY shall ensure deployment of CONTINGENCY RESERVE is sustainable for a minimum of 30 minutes following the contingency event.

5. **Verification of Performance.** The OPERATING AUTHORITY shall verify that all IOS RESOURCES requested to provide CONTINGENCY RESERVE – SPINNING, and SUPPLEMENTAL do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.

6. **Restoration of CONTINGENCY RESERVE.** The OPERATING AUTHORITY shall develop clear operating plans and procedures to assure the timely deployment and restoration of CONTINGENCY RESERVE. These plans and procedures shall specify how CONTINGENCY RESERVE shall be restored, for example, how and when schedules are curtailed, replaced, or initiated.

### Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. **Declaration of CONTINGENCY RESERVE Capability.** An IOS SUPPLIER that has agreed to provide CONTINGENCY RESERVE shall declare to the OPERATING AUTHORITY the IOS RESOURCE'S capabilities.

**8. IOS RESOURCE Response.** An IOS RESOURCE offered to provide CONTINGENCY RESERVES shall be:

**8.1.** Responsive to the instructions and/or variable scheduled output supplied by the OPERATING AUTHORITY.

**8.2.** Continuously synchronized to the system, when providing CONTINGENCY RESERVES – SPINNING SERVICE.

**8.3.** Available for redeployment after the pre-arranged elapsed time as specified by the IOS SUPPLIER.

**9. Provision of CONTINGENCY RESERVES.** In response to the instructions of the OPERATING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall:

**9.1.** Provide between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING within ($T_{DCS}$ – X) minutes of a call by the OPERATING AUTHORITY requesting CONTINGENCY RESERVE. X is the number of minutes agreed to in advance by the OPERATING AUTHORITY and IOS SUPPLIER that allows for the OPERATING AUTHORITY to respond to a contingency and call for deployment of CONTINGENCY RESERVE.

**9.2.** Maintain between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING for at least 15 minutes subsequent to ($T_{DCS}$ – X).

**9.3.** Return to the non-contingency scheduled output (or consumption) +/– 10% of the requested amount of CONTINGENCY RESERVE, within ten minutes of instructions from the OPERATING AUTHORITY to do so. Alternatives to the +/- 10% bandwidth and the ten minute period may be established by the Operating Authority through an open process defined in Requirement 2 - Section 3.1 – Operating Authority Requirements.

**10. Maintaining Reserve Capacity.** An IOS SUPPLIER shall maintain the capacity committed to provide CONTINGENCY RESERVE throughout the commitment period.

**11. Metering and Communication.** An IOS SUPPLIER offering to provide CONTINGENCY RESERVE shall meet the following minimum metering and communication requirements:

**11.1.** The IOS SUPPLIER shall provide to the OPERATING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE providing CONTINGENCY RESERVE.

**11.2.** The IOS RESOURCE shall have an OPERATING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the CONTROL AREA.

**11.3.** The IOS RESOURCE shall have an OPERATING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the OPERATING AUTHORITY and the operator controlling the IOS RESOURCE.

## 3.4 Sample REACTIVE POWER SUPPLY FROM GENERATION SOURCES Requirements

### Sample Requirements – Operating Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

**IOS RESOURCE here refers only to those resources providing REACTIVE POWER SUPPLY FROM GENERATION SOURCES.**

1. **Voltage Schedule Coordination.** The OPERATING AUTHORITY shall establish, and update as necessary, voltage schedules at points of integration of REACTIVE POWER SUPPLY FROM GENERATION SOURCES, to maintain system voltages within established limits and to avoid burdening neighboring systems. The OPERATING AUTHORITY shall communicate to the IOS SUPPLIER the desired voltage at the point of integration.

2. **Reactive Reserves.** The OPERATING AUTHORITY shall acquire, deploy, and continuously maintain reactive reserves from IOS RESOURCES, both leading and lagging, adequate to meet contingencies.

3. **Telemetry.** The OPERATING AUTHORITY shall monitor by telemetry the following data:

   **3.1.** Transmission voltages.

   **3.2.** Unit or IOS RESOURCE reactive power output.

   **3.3.** Unit or IOS RESOURCE Automatic Voltage Regulator (AVR) status for units greater than 100 MW (and smaller units where an identified need exists).

4. **NERC Planning Standards.** The OPERATING AUTHORITY shall comply with NERC Planning Standards applicable to reactive power capability. These standards require that generation owners and OPERATING AUTHORITIES plan and test reactive power capability.

### Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

5. **Automatic Voltage Regulator.** An IOS RESOURCE shall operate with the unit's AVR in use during the schedule period in which REACTIVE POWER SUPPLY FROM GENERATION SOURCES is provided, unless specifically directed to operate in manual mode by the OPERATING AUTHORITY, or a need to operate in manual mode is identified for emergency reasons by the IOS SUPPLIER. When the IOS SUPPLIER changes the mode, the IOS SUPPLIER shall promptly inform the OPERATING AUTHORITY.

6. **Response to Voltage or Reactive Power Schedule Changes.** IOS RESOURCES shall meet, within established tolerances, and respond to changes in the voltage or reactive power schedule established by the OPERATING AUTHORITY, subject to the stated IOS RESOURCE reactive and real power operating characteristic limits and voltage limits.

7. **Reactive Capacity.** IOS RESOURCES shall maintain stated reactive capacity, both leading and lagging. An IOS RESOURCE's stated lagging reactive capacity shall be supplied without interruption or degradation when subject to sudden and large voltage drops.

8. **Telemetry.** IOS RESOURCEs shall provide electronic transfer of real-time information to the OPERATING AUTHORITY:

   **8.1.** Voltages at the IOS RESOURCE point of delivery to the OPERATING AUTHORITY.

   **8.2.** IOS RESOURCE reactive power output, and

   **8.3.** IOS RESOURCE AVR status for units of greater than 100 MW of nameplate capacity (and smaller units where an identified need exists).

## 3.5 Sample FREQUENCY RESPONSE Requirements

### Sample Requirements – Operating Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The OPERATING AUTHORITY shall determine the IOS requirements for FREQUENCY RESPONSE in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics.

2. **Provision.** The OPERATING AUTHORITY shall assure sufficient capabilities for FREQUENCY RESPONSE are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **Verification of Performance.** The OPERATING AUTHORITY shall verify that all IOS RESOURCES contracted to provide FREQUENCY RESPONSE do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.

### Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

4. **Declaration of FREQUENCY RESPONSE Capability.** Prior to providing FREQUENCY RESPONSE, the IOS SUPPLIER shall declare the FREQUENCY RESPONSE capabilities of the IOS RESOURCES.

5. **Governor.** An IOS RESOURCE providing FREQUENCY RESPONSE capability shall maintain an operable governor system and shall be responsive to system frequency deviations.

6. **Maintaining FREQUENCY RESPONSE Capacity.** An IOS SUPPLIER shall maintain the governor response capability to provide FREQUENCY RESPONSE throughout the commitment period.

7. **Metering and Communication.** An IOS SUPPLIER offering to provide FREQUENCY RESPONSE shall have frequency metering and generation output metering sufficient to determine on an after the fact basis that the generator delivered the response required.

## 3.6 System Black Start Capability

### Sample Requirements – Operating Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Restoration Plans.** The OPERATING AUTHORITY shall verify that restoration plans meet NERC, applicable Regional Reliability Council, and local requirements, and provide for adequate SYSTEM BLACK START CAPABILITY.

2. **System Black Start Requirements.** The OPERATING AUTHORITY shall determine the overall required amount and locations of SYSTEM BLACK START CAPABILITY in a system restoration plan for the coordinated re-energization of the transmission network following a total or partial system blackout.

3. **Training and Drills.** The OPERATING AUTHORITY shall include IOS RESOURCES providing SYSTEM BLACK START CAPABILITY in the conduct of system-wide training, and drills, as necessary to prepare a coordinated response to a partial or total system blackout condition.

4. **Provision of SYSTEM BLACK START CAPABILITY.** The OPERATING AUTHORITY shall ensure IOS RESOURCES for SYSTEM BLACK START CAPABILITY are arranged, provided, and deployed as necessary to reenergize the transmission network following a total or partial system blackout.

5. **Testing and Verification**. The OPERATING AUTHORITY shall schedule random testing or simulation, or both, to verify SYSTEM BLACK START CAPABILITY is operable according to the restoration plan. Testing and verification will be in accordance with established certification criteria. These tests and/or simulations shall ensure that the SYSTEM BLACK START resources and transmission system are configured such that the SYSTEM BLACK START CAPABILITY resources are able to energize the appropriate portions of the transmission system, and supply restoration power to the generator(s) or load(s), as required by the restoration plan. The SYSTEM BLACK START CAPABILITY resources must provide frequency and voltage within prescribed limits during line energization and remote load pickup.

6. **Performance Verification.** The OPERATING AUTHORITY shall verify the actual performance of SYSTEM BLACK START CAPABILITY resources in the event actual system blackout conditions occur.

## Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

**7. IOS RESOURCE Capabilities.** An IOS SUPPLIER of SYSTEM BLACK START CAPABILITY shall provide the following:

**7.1.** Capability to start a self-starting unit within a time specified, from an initial dead station and auxiliary bus condition. Alternately, a SYSTEM BLACK START RESOURCE may be a generating unit that is able to a) safely withstand the sudden and unplanned loss of synchronization with the BULK ELECTRIC SYSTEM and b) maintain generating capacity for a specified period of time.

**7.2.** Capability of re-energizing, within a time specified, the plant auxiliaries necessary to start one or more additional units, if the SYSTEM BLACK START CAPABILITY unit is planned as a cranking source for one or more of these additional units.

**7.3.** Capability of picking up external load within a specified time.

**7.4.** Stated MW capacity of the SYSTEM BLACK START CAPABILITY unit or units.

**7.5.** Capability of running the SYSTEM BLACK START CAPABILITY unit at stated MW capacity for a specified time from when the unit is started.

**7.6.** Frequency measurement at the SYSTEM BLACK START CAPABILITY unit to support the system restoration plan.

**7.7.** Frequency responsive capability to sustain scheduled frequency and remain stable during load pickup coordinated by the OPERATING AUTHORITY in accordance with the restoration plan.

**7.8.** Reactive supply and voltage control capability to maintain system voltage within emergency voltage limits over a range from no external load to full external load.

**7.9.** Participation in training and restoration drills coordinated by the OPERATING AUTHORITY.

**7.10.** Provision of voice and data communications with the OPERATING AUTHORITY, capable of operating without an external AC power supply for a specified time.

# D
# EXCERPTS FROM CAISO MANAGEMENT OF ANCILLARY SERVICES CERTIFICATION TESTING

CALIFORNIA ISO

California Independent System Operator

## EXCERPTS FROM

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# CAISO Management of Ancillary Services Certification Testing

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11/28/01

# Table of Contents

NOTE: Grayed text has been deleted from this excerpt. See the note on the cover for source of full document.

# INTRODUCTION

## Purpose

This procedure describes the process that will be used by the ISO to certify resources, including Generating Units, Curtailable Demand, and System Resources to provide Ancillary Service (A/S) to the ISO Controlled Grid.

A Generating Unit is an individual electric generator that is physically located within the ISO Control Area.

Curtailable Demand is demand from a participating load that can be curtailed at the direction of the ISO in the real time dispatch of the ISO Controlled Grid.

A System Resource is an individual or group of resources located outside the ISO Control Area capable of providing Energy and/or A/S to the ISO Controlled Grid.

For provision of Regulation into the ISO Control Area, a System Resource is a generating unit or generating plant or any portion thereof located within a host Control Area or imported into a host Control Area or an allocated portion of the host Control Area's EMS/AGC which is directly responsive to, and it's Control Area generation level is controlled by, the host Control Area EMS/AGC.

A resource's capability to provide A/S is determined by measuring the resource's ability to respond to a variety of Dispatch instructions. Actual test performance of a resource will result in certified values for the resource, which are then used in the ISO's operating systems to validate A/S which are bid or self-provided.

## Affected Parties

- California ISO
  - Grid Operations
  - Operations Support and Training
  - Operations Engineering and Maintenance
  - Outage Coordination
  - Client Relations
  - Metering: MDAS
  - Contracts and Compliance
  - Market Operations
  - Application Services
- Scheduling Coordinators
- Resource Owners

## References

| | |
|---|---|
| • ISO Tariff | Periodic Testing of Units |
| • ISO Tariff | Metering Infrastructure |

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|---|---|---|
| • ISO Protocol | Ancillary Services Requirement Protocol (ASRP) of the ISO Tariff | |
| • ISO Operating Procedure | G-203: | Reliability Must Run Unit Commitment and Dispatch |

## Policy

The ISO Tariff gives the ISO the authority to test resources that desire to bid or self-provide Ancillary Services (A/S).

The ISO must assure that all Resources providing A/S meet the ISO's technical requirements and that Market Participants are fairly compensated for A/S provided. Therefore the ISO testing process must achieve the following:

- Assure consistent evaluation techniques
- Determine the Resource capabilities such that the full range of A/S can be identified
- Accurately identify service specific limitations
- Validate data provided by requestor on A/S Certification Request and Testing Form

The ISO will test resource capabilities for both initial certifications and validation of existing certification to ensure that the standards for performance and associated operating values are properly represented in the ISO operating systems.

## Definitions

Unless the context otherwise indicates, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning wherever capitalized in this procedure.

The following additional terms, if any, are capitalized in this document when used as defined below:

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| **Certified Value** | The specific value of P-max, P-min, or ramp rate used by the ISO, the PX, the SCs, and the resource owners for bidding and bid validation of A/S. Certified Values may vary for different A/S on a single Generating Unit. |
| **Start Time** | For non-Regulation A/S certification tests, the instant that both the time and the starting point (i.e. start data) are recorded by a screen-print (and/or flagged on a trend chart) and the test administrator notifies the SC that the test is started. For Regulation certification tests, the time that the REGULATION set point is changed as indicated on EMS or PI (Plant Information system) trend. |
| **Stated P-max** | The maximum MW level that a given Generating Unit, Curtailable Demand, or System Resource is |

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| | capable of sustaining for a determined period of time as stated by the resource Owner and/or SC on the A/S Certification Request and Testing Form. |
| **Stated P-min** | The lowest MW level not less than zero that a given Generating Unit, Curtailable Demand, or System Resource is capable of sustaining for a determined period of time as stated by the Generator and/or SC on the A/S Certification Request and Testing form. |
| **Stated Ramp Rate** | The rate at which a resource can increase or decrease output for a particular A/S as stated by the resource owner and/or SC on the A/S Certification Request and Testing form. The Stated Ramp Rate may vary for different MW ranges on a given Generating Unit, Curtailable Demand, or System Resource. Ramp Rate is measured in MW/minute. |
| **Tested P-max** | The maximum sustainable MW level for a given Generating Unit, Curtailable Demand, or System Resource as demonstrated during tests and reflected on the ISO EMS. The Tested P-max must be sustainable for a power factor range between .95 leading to .90 lagging. |
| **Tested P-min** | The lowest sustainable MW level for a given Generating Unit, Curtailable Demand, or System Resource as demonstrated during tests and reflected on the ISO EMS. |
| **Tested Ramp Rate** | The rate at which a resource can increase or decrease output for a particular A/S as tested and calculated by the ISO. The Tested Ramp Rate may vary for different MW ranges on a given Generating Unit, Curtailable Demand, or System Resource. Ramp Rate is measured in MW/minute. |

## Responsibilities

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| **Client Relations – Client Representative** | Arrange for certification of the values submitted by the Scheduling Coordinator on the A/S Certification Request and Testing Form. Coordinate testing and exchange of data between the Scheduling Coordinator (SC), Grid Operations, Outage Coordination (O/C), and the Market Operations Master File Coordinator. |
| **Contracts and Compliance - Compliance Analyst** | Ensure a nondiscriminatory testing process. Initiate spot test for compliance. Direct review of testing procedures |

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| **OSAT Test Administrator** | Perform tests and manage test data. Coordinate with ISO Operations, SC, and resource owner to perform tests |
| **Outage Coordination** | Approve and schedule testing |
| **Scheduling Coordinators (SC)** | Submit requests for testing and coordinate between ISO and resource owner for test scheduling, testing, and data management |
| **Operations Engineering & Maintenance** | Check test data for reasonability and approve Master File changes |

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# GENERATING UNIT CERTIFICATION PROCEDURE

## 1. TECHNICAL INFORMATION REGARDING ANCILLARY SERVICES TESTING AND CERTIFICATION

### 1.0. Test Duration

The time typically allocated to perform testing will be one to two hours, as specified in the ASRP of the ISO Tariff. The complete test time will depend upon the A/S being tested, the type of Generating Unit, and the system conditions at the time of the test.

### 1.1. Test Energy

Energy over or under produced due to testing is accounted for as Balancing Energy. Appropriate log entries will be made to assure that "no-pay" settlements and penalties are not assessed during the testing period.

### 1.2. Response Time and Communication Time

For non-Regulation tests, the specified test periods (10 or 60 minutes) include the SC and Generating Unit operator response time as well as all communication time. That is, the test period begins with the initial contact between the ISO and the SC.

For Regulation tests, the specified test periods (10 minutes) include time required for real-time and control telemetry to affect change in Generating Unit output.

### 1.3. Testing Sequence

For a given resource certifying multiple values, it is not necessary to perform the tests in any particular order. The order should be determined by a combination of:

- System conditions
- Generation Dispatcher needs and restrictions; and
- Coordination between the Generating Unit, the SC and the ISO (for certification tests)

### 1.4. Multiple Use of Test Data

It is not always necessary to test for each A/S requested for certification as some test results can be used as demonstration for multiple A/S.

#### 1.4.1. Use of Spin test data for Non-Spin certification

At times it is impractical to separate a Generating Unit from the grid for testing if the Generating Unit is intended to bid for Non-Spinning Reserves only when it is on-line.

Generating Units will be certified to bid for Non-Spinning Reserves as tested:

1) **On line Non-Spinning Reserve Testing**

If a given Generating Unit is tested for Non-Spinning Reserves while synchronized to the grid (on line), the Spinning Reserves test data can be used for Non-Spinning A/S certification. Additional testing is not necessary. The Non-Spinning Reserve test results shall be identical to the Spinning Reserve test results. Test data shall include notice that the Generating Unit was tested in this manner and is qualified only for on-line bidding of Non-spinning Reserve.

2) **Off line Non-Spinning Reserve Testing**

In the event it is reasonably certain that a Generating Unit will be bid for Non-Spinning Reserves when it is off-line, the test for Non-Spinning Reserve <u>must</u> start with the Generating Unit off-line. The Spin test data shall not be used as a demonstration of adequate ability to provide Non-spinning Reserve.

#### 1.4.2. Use of Non-spin test data for Replacement Reserves certification

If the Generating Unit, ramping at the Tested Ramp Rate determined by the Non-spin test, would clearly reach P-max in less than 30 minutes, the Non-spin test data can be used for Replacement Reserves certification. (This 30-minute criteria allows for a broad margin of error that can be encountered in an actual 60-minute test.) Otherwise, the Generating Unit must be tested either from off-line to P-max or for 60 minutes to determine how much power can actually be delivered within 60 minutes. If it is anticipated that the Generating Unit will ever be off-line when bid for this service, it must be tested starting off-line (or use data from a Non-spin test that started off-line).

### 1.5. Decimal Places

Observed and stated data are recorded to one decimal place accuracy. Calculations of ramp rates are stated and recorded to two decimal places.

### 1.6. Test Periods

#### 1.6.1. Recording

The calculations performed on the data will be valid as long as the start and stop times are recorded to the one tenth of a second. Therefore, if the available operating range of a Generating Unit is less than the range that would be covered by a ten-minute ramp, a shorter test period may be used. Also, if the test does not end at exactly the correct time, results will be valid as long as a screen-print can be taken by the ISO at the exact end time.

#### 1.6.2. Test termination

Ramp rate test termination is either the end of the specified test time (10 minutes or 60 minutes) or the time the resource reaches a limit.

#### 1.6.3. Two-hour tests

Any A/S provider must be capable of providing such Energy or Reserve in the way of a Load for as long as two hours.

### 1.7. Visibility

In order to facilitate reliable testing, any Generating Unit bidding A/S must be directly visible to ISO operations EMS. The OSAT Test Administrator will confirm Generating Unit visibility prior to administering the test.

### 1.8. Exceptions

#### 1.8.1. PX Resources

For testing purposes, PX controlled resources are dispatched directly through the Scheduling Coordinators or plant operators.

#### 1.8.2. Physical Scheduling Plants and aggregated resources

Test Generating Units as a group if they will be bid as a group.

### 1.9. Re-testing

#### 1.9.1. At SC request

If changes have occurred in the status of the facilities that substantially affect the facility's ability to deliver A/S, re-testing shall be accommodated. The re-test values will replace previous test results for certification, even if they result in reductions in certification values.

#### 1.9.2. At ISO request

The ISO will schedule re-testing of resources on a non-discriminatory basis.

### 1.10. RMR Unit Capacity

Generating Units that are RMR Units will be tested using this procedure for market and A/S values only. RMR Unit capacity for availability is not equivalent to A/S P-max. The RMR Contract defines the RMR Capacity for Availability.

### 1.11. Regulation Requirements

#### 1.11.1. Response time delay

Delayed response time (the time between receiving a control signal indicating a change in REGULATION set point and the instant the Generating Unit initiates changes to MW output) is a significant factor to ISO reliability. If tests indicate that Regulation is not reliable on certain Generating Units or in specific ranges, Regulation service will not be certified on those Generating Units or in those ranges.

#### 1.11.2. Symmetrical Regulation certification

Symmetrical Regulation Up and Regulation Down (Regulation up ramp rate and Regulation down ramp rate must be equal) values are necessary for proper operation of EMS. Total Regulation Up Ramp Rates need to be equal to Total Regulation Down Ramp Rates or control will be biased in one direction. Therefore the single "Certified Value" for Regulation will be the lesser of Regulation Up and Regulation Down ramp rates.

### 1.12. Required Forms and Screen-prints

#### 1.12.1. Ancillary Services Certification Request and Testing Form

The A/S Certification Request and Testing Form (see Attachment A) is the official documentation of test requests, performed test data, and certification values. The data is supported by and based upon visible test results and screen-prints. It may be completed and signed by either the test administrator or other ISO staff evaluating test results.

#### 1.12.2. Screen-prints

The ISO will make EMS display screen-prints **or** PI trend printouts of the following:

- the appropriate Generating Unit Station one-line,
- the AGC (Automatic Generation Control) page
- the Generation page
- prepared EMS trend charts, including MW output and set points (see Attachment C: Trend Chart Setup),
- PI trend

## 2. SCHEDULING THE TEST

### 2.0. OSAT Test Administrator Blocks dates

Periodically update test calendar to block out unavailable test dates.

### 2.1. Scheduling Coordinator Submits A/S Certification Request and Testing Form

E-mail Client Representative completed A/S Certification Request and Testing Form (Attachment A) and request testing. See 2.5 for minimum completion requirements.

### 2.2. Client Representative Schedules Test Date

Check calendar for available date and submit Test Form to OSAT Test Administrator. Allow a minimum 10 calendar days of lead-time.

### 2.3. OSAT Test Administrator Accepts Test Date

Accept or decline test date. Give reason for decline. E-mail response to Client Representative.

### 2.4. Client Representative Notifies Scheduling Coordinator

Contact Scheduling Coordinator with accepted or revised test date. Confirm receipt of A/S Certification Request and Testing Form (Attachment A) completed with at least:

- Agency and contact telephone number
- Resource ID
- All “Yes” boxes checked (Attachment A)
- Stated Values included in test data block

### 2.5. Scheduling Coordinator Schedules With Outage Coordination

Schedule test date with ISO Outage Coordination. Submit Owner resource owner Outage Request form (Attachment D to this Procedure also posted on Client Relations A/S web site). Outage Coordination requires 72 work-week hours to schedule the testing. For example, requests must be submitted by Thursday noon for testing to occur on the following Tuesday. A/S tests not scheduled through ISO Outage Coordination will not be conducted.

## 3. PERFORMING THE TEST(S)

The steps listed in the following tables comprise standardized testing procedures:

### 3.0. Generating Units

### 3.0.1. P-max P-min or RMR Capacity for Availability Test

| | | P-MAX P-MIN TEST |
|---|---|---|
| | STEP | INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF) |
| 1 | **Review A/S Certification Request and Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All “Yes” boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| 2 | **Confirm scheduled certification test** | **Contact** the SC to clarify the schedule and nature of the tests to be performed. |

| | | |
|---|---|---|
| **3** | **Determine whether system conditions support test** | **Check** available Regulation to compensate for fluctuation of Generating Units being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. If testing an RMR Unit for A/S Certification, check with Alhambra Generation Dispatcher. The ISO will not dispatch additional RMR Units to facilitate A/S testing. |
| **4** | **Position Generating Unit start point for optimum response** | Order SC to adjust to upper or lower limit. |
| **5** | **Start test** | **Notify** SC of start time (this contact is the Start Time) and request:<br>**P-max** – to maintain maximum output for 15 minutes.<br>**P-min** – to maintain minimum output for 15 minutes. |
| **6** | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| **7** | **Monitor MW level** | **P-max –** for 15 minutes, noting minimum level during the 15 minute period (take additional screen-prints if necessary to record MW level variations<br>While maintaining P-max, <u>if system conditions allow</u>, instruct SC to adjust Generating Unit power factor. For .95 leading power factor, the Generating Unit should try to take in (buck) an amount of MVAR equal to 33% of its MW output. For .90 lagging power factor, the Generating Unit should try to produce (boost) an amount of MVAR equal to 48.5% of its MW output.<br>If the required MVAR output is unattainable at a given P-max, the limiting factor (such as terminal voltage limit reached, or field current limit is reached) is to be noted and the test repeated at a lower P-max. Operations Engineering and Maintenance will evaluate the data to determine pass or failure of the test.<br>The SC may adjust MVAR of other Generating Units to accommodate the MVAR test.<br>**P-min** – for 15 minutes, noting highest level during the 15 minute period (take additional screen-prints if necessary to record MW level variations).<br>**RMR capacity for availability –** for four full scheduling hours. |
| **8** | **End test** | **P-max, P-min –** after 15 minutes.<br>**ISO calls end of complete timed test.** |
| **9** | **Record end time and MW level.** | **Screen-print** – showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |

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| **10** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify:** Notify all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information). |
| **11** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Complete at least Test Administrator and contacts Name. Include any other recorded data.<br>**Screen-prints:** Sequence Chronologically and note purpose of each screen-print. For example:" Begin Reg Up." |

### 3.0.2. Regulation Ramp Rate Test

| | | REGULATION RAMP RATE TEST |
|---|---|---|
| | STEP | INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF) |
| 1 | **Review A/S Certification Request ant Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All "Yes" boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| 2 | **Confirm scheduled certification test** | **Contact** SC to clarify the schedule and nature of the tests to be performed. |
| 3 | **Determine whether system conditions support test** | **Check** available regulation to compensate for fluctuation of Generating Units being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. If testing an RMR Unit for A/S Certification, check with Alhambra Generation Dispatcher. The ISO will not dispatch additional RMR Units to facilitate A/S testing. |
| 4 | **Position Generating Unit start point for optimum response** | **Allow** enough room for ten minutes of ramping in the Stated Ramp Range. Preferably start at bottom or top of REGULATION range. |
| 5 | **Prepare Generating Unit** | **Assure:**<br>• Generating Unit on REGULATION.<br>• Unit blocks are clear from testing range. |
| 6 | **Prepare EMS** | **Request** Alhambra Generation Dispatcher to Assure:<br>• Control flag is on (REGULATION---see ACC Unit Summary).<br>• Reg limits are outside of testing range.<br>• "ISO Ramp Rate" is above Stated Ramp Rate (see AGC---ACC Unit Summary). |
| 7 | **Start test** | **Notify** SC of testing. Manually replace Set Point to a level at least 10 times the Stated Ramp Rate above or below start point.<br>**(Start Time is the time that the Set Point is changed, as indicted on EMS or PI trend).** |
| 8 | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| 9 | **Monitor MW level** | **For** 10 minutes or until Generating Unit reaches upper or lower REGULATION limit. |
| 10 | **End test** | **After** 10 minutes or when Generating Unit reaches upper or lower REGULATION limit.<br>**ISO calls end of complete timed test.** |

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| | | **SC calls end if limit is reached.** |
| **11** | **Record end time and MW level.** | **Screen-print** – showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |
| **12** | **Repeat test** | **Repeat** test if necessary. |
| **13** | **Additional Regulation testing** | **Range validation:** Generating Unit may be required to control across entire REGULATION range to verify the reliability of the upper and lower limits.<br>**Response time:** Note the length of time between Set Point change and Generating Unit response. This additional data will be used to evaluate the performance and reliability of the Generating Unit for Regulation. |
| **14** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards<br>**Notify:** Notify all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information) |
| **15** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Complete at least Test Administrator Name. Include any other recorded data.<br>**Screen-prints:** Sequence Chronologically and note purpose of each screen-print. For example: "Begin Reg Up." |

### 3.0.3. Spin Ramp Rate Test

| | | |
|---|---|---|
| | | **SPIN RAMP TEST** |
| | **STEP** | **INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF)** |
| **1** | **Review A/S Certification Request and Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All "Yes" boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| **2** | **Confirm scheduled certification test** | **Contact** SC to clarify the schedule and nature of the tests to be performed. |
| **3** | **Determine whether system conditions support test** | **Check** available regulation to compensate for fluctuation of Generating Units being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. If testing an RMR Unit for A/S Certification, check with Alhambra Generation Dispatcher. The ISO will not dispatch additional RMR Units to facilitate A/S testing. |
| **4** | **Position Generating Unit start point for optimum response** | **Allow** enough room for ten minutes of ramping at the Stated Ramp Rate. |

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| **5** | **Start test** | **Notify** SC of start time (this contact is the Start Time) and request to increase output at maximum allowable rate until instructed to stop (will be in 10 minutes for Spin and Non-Spin, 60 minutes for Replacement) or P-max is reached. (see Section 1.3). |
| **6** | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| **7** | **Monitor MW level** | **For** 10 minutes or until Generating Unit reaches P-max. |
| **8** | **End test** | **After** 10 minutes or when Generating Unit reaches P-max. |
| **9** | **Record end time and MW level.** | **Screen-print** – showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |
| **10** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify:** Notify all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information). |
| **11** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Test Administrator to sign form. Include any other recorded data. (Screen-prints, etc.)<br>**Screen-prints:** Sequence Chronologically and note purpose of each screen-print. For example: "Begin Reg Up." |

### 3.0.4. Non-Spin Ramp Rate Test

| | | NON-SPIN RAMP RATE TEST |
|---|---|---|
| | STEP | INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF) |
| **1** | **Review A/S Certification Request and Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All "Yes" boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| **2** | **Confirm scheduled certification test** | **Contact** SC to clarify the schedule and nature of the tests to be performed. |
| **3** | **Determine whether system conditions support test** | **Check** available regulation to compensate for fluctuation of Generating Units being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. If testing an RMR Unit for A/S Certification, check with Alhambra Generation Dispatcher. The ISO will not dispatch additional RMR Units to facilitate A/S testing. |
| **4** | **Position Generating Unit start point for optimum response** | **Start** off-line or use Spin data. (see Section 1.5). |
| **5** | **Start test** | **Notify** SC of start (this contact is the Start Time) and request to increase output at maximum allowable rate until instructed to stop (will be in 10 minutes) or P-max is reached. (see Section 1.3). |
| **6** | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| **7** | **Monitor MW level** | **For** 10 minutes or until Generating Unit reaches P-max (or until Curtailable Demand is fully reduced). |
| **8** | **End test** | **After** 10 minutes or when Generating Unit reaches P-max (or when Curtailable Demand is fully reduced).<br>**ISO calls end of complete timed test.**<br>**SC calls end if limit is reached.** |
| **9** | **Record end time and MW level.** | **Screen-print** – showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |
| **10** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify:** Notify all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule |

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| | | information). |
| **11** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Test Administrator to sign form. Include any other recorded data.<br>**Screen-prints:** Sequence Chronologically and note purpose of each screen-print. For example: "Begin Reg Up." |

### 3.0.5. Replacement Ramp Rate Test

| | | REPLACEMENT RAMP RATE TEST |
|---|---|---|
| | STEP | INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF) |
| 1 | **Review A/S Certification Request and Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All "Yes" boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| 2 | **Confirm scheduled certification test** | **Contact** SC to clarify the schedule and nature of the tests to be performed. |
| 3 | **Determine whether system conditions support test** | **Check** available regulation to compensate for fluctuation of Generating Units being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. If testing an RMR Unit for A/S Certification, check with Alhambra Generation Dispatcher. The ISO will not dispatch additional RMR Units to facilitate A/S testing. |
| 4 | **Position Generating Unit start point for optimum response** | **Start** off-line or at minimum, or use NSP data. (see Section 1.5) |
| 5 | **Start test** | **Notify** SC of start time (this contact is the Start Time) and request to increase output at maximum allowable rate until instructed to stop (will be in 10 minutes for Spin and Non-Spin, 60 minutes for Replacement) or P-max is reached. (see Section 1.3). |
| 6 | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| 7 | **Monitor MW level** | **For** 60 minutes or until Generating Unit reaches P-max. ALSO: Note Time Generating Unit Starts. |
| 8 | **End test** | **After** 60 minutes or when Generating Unit reaches P-max.<br>**ISO calls end of complete timed test.**<br>**SC calls end if limit is reached.** |
| 9 | **Record end time and MW level.** | **Screen-print** – showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |

| | | |
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| **10** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify** all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information) |
| **11** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Test Administrator to sign form. Include any other recorded data.<br>**Screen-prints:** Sequence Chronologically and note purpose of each screen-print. For example: "Begin Reg Up." |

## 4. CALCULATING TEST RESULTS

The processing of test data occurs, all or in part, after the testing procedure has been completed and may be performed by a party other than the test administrator and at a later time. The test administrator may send the documentation, including test forms and screen-prints, to the data manager or other personnel for some or all of the following steps:

| | | |
|---|---|---|
| **1** | **Calculate results** | Ramp rates and P-max/min levels are recorded to two decimal places.<br>**REFER TO DATA BLOCK ON A/S CERTIFICATION REQUEST AND TESTING FORM.**<br>**Complete:** “Start Time,” “Start MW,” “End Time,” and “End MW” in the data block with data from the test screen-prints.<br>**Calculate results:** From data recorded in “Starting Time,” “Starting Point,” “Ending Time,” and “Ending Point,” calculate and indicate in “Certified Value”.<br>**MW Change:** = {End MW – Start MW} (one decimal place).<br>**MW Range**: Indicates various test ranges (completed by SC).<br>**Stated P-max, P-min, or Ramp Rate:** (completed by SC).<br>**Certified P-max:** = Lowest level during the 15-minute test period (tenths of a MW).<br>**Certified P-min: =** Highest level during the 15-minute test period (tenths of a MW).<br>**Certified Ramp Rate:** = {MW change/(End time – Start time*)} (two decimal places).<br>**Note for Regulation:** Symmetrical Reg Up and Reg Down values are necessary for proper operation of EMS. Therefore the single “Certified Value” for Reg will be the lesser of Reg Up and Reg Down.<br>*Convert seconds to hundredths of minutes by dividing seconds by 60. |
| **2** | **Organize documentation packet** | **Fasten documents:** in the following order: |

| | | |
|---|---|---|
| **3** | **Record data and results** | **In Certification Data file –** The format and structure of the Certification Data file is similar to the data blocks on the Request forms. The test data accumulated during testing along with the calculations performed above should be entered in the Certification Data file exactly as on the Request forms. Note: The lesser of Reg Up and Reg Down ramp rates from the "Observed" field becomes the "Service Specific Certification" value for both.<br><br>**Certified Values –** The values derived from the tests and entered in the Certification Data file, once approved by the Operations Engineer, are used as the certified values for bidding and validation. |
| **4** | **Archive Data** | **The OSAT Test Administrator** will file the data package in the particular file for the appropriate Generating Unit. |
| **5** | **Forward Data and Calculations to Client Representative** | **The OSAT Test Administrator** will notify the Client Representative of the Certification Data file changes and additions. |

# 5. PROCESSING OF CERTIFICATION VALUES

## 5.0. Approval

### 5.0.1. Client Relations – Client Representative review data

Review Certification Data file test data for consistency with established procedure. Extract test data and calculations and send to Operations Engineer.

### 5.0.2. Operations Engineering and Maintenance – Operations Engineer review data

Evaluate test data and calculated certification values for reasonability and accuracy, and approve data to be used as Certified Values.

Forward Certified Values to Client Representative.

## 5.1. Master File Update

### 5.1.1. Client Relations – Client Representative enter change request

Enter a change request into the ISO's Change Management system to be routed to Market Operations for processing.

### 5.1.2. Market Operations – Master File Engineer update Master File

Coordinate with Market Participants and ISO Operations, enter the Certified Values into the ISO Master File, and notify the Client Representative of new data effective date.

## 5.2. Notification

### 5.2.1. Client Relations – Client Representative notifies SC

Notify SC of Master File update and effective date. Provide SC with appropriate certification documentation, including test data and calculations.

### 5.2.2. Client Relations – Client Representative notifies ISO Operations

Notify ISO Operations of new A/S resources.

## 5.3. PGA Schedule 1 Revision

### 5.3.1. Scheduling Coordinator notifies resource owner

Have resource owner submit a revised Participating resource owner Agreement Schedule 1 reflecting new Certified Values to the ISO

### 5.3.2. Contracts and Compliance – Compliance Analyst file with FERC

Receive revised Participating Generator Agreement Schedule 1 from resource owner, and file it at FERC for information purposes.

# 6. PROCEDURE COMPLIANCE MANAGEMENT

## 6.0.1. Contracts and Compliance – Compliance Analyst conduct periodic review

Conduct periodic review of test results and the certification process to ensure nondiscriminatory testing.

Monitor the bidding and provision of A/S, and develop market-based methods and techniques to foster quality A/S provision and fair remuneration.

# SYSTEM RESOURCE CERTIFICATION PROCEDURE

## 13. TECHNICAL INFORMATION REGARDING ANCILLARY SERVICES

### 13.0. TECHNICAL INFORMATION REGARDING ANCILLARY SERVICES TESTING AND CERTIFICATION

### 13.1. Test Duration

The time typically allocated to perform testing will be one to two hours. The complete test time will depend upon the A/S being tested, the type of System Resource, and the system conditions at the time of the test.

### 13.2. Response Time and Communication Time

For non-Regulation tests, the specified test periods (10 or 60 minutes) include the SC and System Resource operator response time as well as all communication time. That is, the test period begins with the initial contact between the ISO and the SC.

For Regulation tests, the specified test periods (10 minutes) include time required for real-time and control telemetry to affect change in dynamic interchange.

### 13.3. Testing Sequence

For a given resource certifying multiple values, it is not necessary to perform the tests in any particular order. The order should be determined by a combination of:

- System conditions
- Generation Dispatcher needs and restrictions; and
- Coordination between the host Control Area operator, the SC and the ISO (for certification tests)

### 13.4. Decimal Places

Observed and stated data are recorded to one decimal place accuracy. Calculations of ramp rates are stated and recorded to two decimal places.

### 13.5. Test Periods

#### 13.5.1. Recording

The calculations performed on the data will be valid as long as the start and stop times are recorded to the one tenth of a second. Therefore, if the available operating range of a System Resource is less than the range that would be covered by a ten-minute ramp, a shorter test period may be used. Also, if the test does not end at exactly the correct time, results will be valid as long as a screen-print can be taken by the ISO at the exact end time.

#### 13.5.2. Test termination

Ramp rate test termination is either the end of the specified test time (10 minutes or 60 minutes) or the time the System Resource reaches a limit.

#### 13.5.3. Two-hour tests

Any A/S provider must be capable of providing such Energy or Reserve in the way of a Load for as long as two hours.

### 13.6. Exceptions

#### 13.6.1. System Resources

For testing purposes, System Resources are dispatched directly through the Scheduling Coordinator and in coordination with the host Control Area.

### 13.7. Re-testing

#### 13.7.1. At SC request

If changes have occurred in the status of the facilities that substantially affect the facility's ability to deliver A/S, re-testing shall be accommodated. The re-test values will replace previous certification test results, even if they result in reductions in certification values.

#### 13.7.2. At ISO request

The ISO will schedule re-testing of System Resources on a non-discriminatory basis.

### 13.8. Initial SC/Control Area Certification of Spin, Non-spin, and Replacement Imports

The SC for the System Resource certifies its ability to deliver Spinning Reserve, Non-Spinning Reserve, and/or Replacement Reserve services by completing the Scheduling Coordinator Certification of External Imports of A/S form (See Attachment B). On the form the SC indicates the amounts deliverable and the points of interchange. With that certification, the SC acknowledges that the ISO Tariff and Protocols require the SC to respond to ISO Dispatch instructions ordering the delivery of Energy associated with bid A/S at any time during the operating hour. The SC further certifies that any and all A/S bid or self-provided as external imports of System Resources will be delivered over non-interruptible, non-recallable transmission rights, from the source of the A/S to the point of interchange with the ISO Control Area.

### 13.9. Initial SC/Control Area Certification for Regulation Imports

In submitting the Scheduling Coordinator & Host Control Area Operator Request for Certification of External Imports of Regulation form (see Attachment E), the SC for the System Resource and its host Control

Area jointly request Certification for Imports of Regulation from the external System Resource(s) into the ISO Control Area utilizing the A/S Certification Request and Testing form (see Attachment A). On the form the SC and host Control Area indicate the maximum amounts of regulating capacity deliverable at specific points of interchange at which such delivery can be scheduled into the ISO. With the certification request, the SC and host Control Area acknowledge that the ISO Tariff, Protocols and standards for Imports of Regulation impose and require certain specific levels of performance. The specific performance requirements include, but are not limited to, the response time of the System Resource to the ISO's EMS/AGC control signals, ramp rate, and operating range limitations. The SC and host Control Area further state that Regulation service, whether bid as imports or self-provided as imports of System Resources, will be delivered over non-interruptible, non-recallable transmission rights, from the source of the A/S to the point of interchange with the ISO Control Area.

## 13.10. ISO issuance of certification

Upon favorable conclusion of the tests and ISO evaluation of the SC certification and related data, the ISO shall provide written notification of acceptance of the SC's ability to deliver A/S to the points of interchange with the ISO Control Area in the amounts indicated in the applicable request form.

## 13.11. Regulation Requirements

### 13.11.1. Symmetrical Regulation certification

Symmetrical Regulation Up and Regulation Down (Regulation up ramp rate and Regulation down ramp rate must be equal) values are necessary for proper operation of EMS. Total Regulation Up Ramp Rates need to be equal to Total Regulation Down Ramp Rates or control will be biased in one direction. Therefore the single "Certified Value" for Regulation will be the lesser of Regulation Up and Regulation Down ramp rates.

## 13.12. Required forms and screen-prints

### 13.12.1. The Import Regulation Certification Test Request form

The Import Regulation Certification Test Request form (see Attachment A) is the official documentation of test requests, performed test data, and certification values. The data is supported by and based upon visible test results and screen-prints. It may be completed and signed by either the test administrator or other ISO staff evaluating test results.

### 13.12.2. Screen-prints

The ISO will make EMS display screen-prints **or** PI trend printouts of the following:

- the AGC (Automatic Generation Control) page
- PI trend

Note: Regulation tests require trending of both REGULATION set point (telemetry/control sent) and MW level (telemetry received).

## 14. SCHEDULING THE TEST

### 14.0. OSAT Test Administrator Blocks dates

Periodically update test calendar to block out unavailable test dates.

### 14.1. Scheduling Coordinator Submits Test and Request Form

E-mail Client Representative A/S Request and Testing Form (Attachment A) and request testing. See Section 14.5 for minimum completion requirements.

### 14.2. Client Representative Schedules Test Date

Check calendar for available date and submit Test Form to OSAT Test Administrator. Allow a minimum 10 calendar days of lead-time.

### 14.3. OSAT Test Administrator Accepts Test Date

Accept or decline test date. Give reason for decline. E-mail response to Client Representative.

### 14.4. Client Representative Notifies Scheduling Coordinator

Contact Scheduling Coordinator with accepted or revised test date. Confirm receipt of A/S Request and Testing Form (Attachment A) completed with at least:

- Agency and contact telephone number
- Resource ID
- All “Yes” boxes checked (Attachment A)
- Stated Values included in test data block

### 14.5. Scheduling Coordinator Schedules With Outage Coordination

Schedule test date with ISO Outage Coordination Office. Submit Owner Generator Outage Request form (Attachment D to this Procedure also posted on Client Relations A/S web site). Outage Coordination requires 72 work week hours to schedule the testing. For example, requests must be submitted by Thursday noon for testing to occur on the following Tuesday. A/S tests not scheduled through ISO Outage Coordination will not be conducted.

## 15. PERFORMING THE TEST(S)

The steps listed in the following tables comprise standardized testing procedures:

## 15.0. System Resources

### 15.0.1. Compliance Test for Imported Spinning, Non-Spinning and Replacement Reserves

| | | **SPIN, NON-SPIN, REPLACEMENT RAMP TEST** |
|---|---|---|
| | **STEP** | **INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF)** |
| 1 | **Review NERC Tag associated with A/S Schedule** | **If no tag:** Test result is fail.<br>**If tag:** Confirm Schedule amounts. |
| 2 | **Determine whether system conditions support test** | **Check** available internal resources to compensate for fluctuation of System Resource being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. |
| 3 | **Start test** | **Notify** SC of start time (this contact is the Start Time) and demand Energy Schedule adjustment effective within ten minutes. (Declaration of test is optional.) |
| 4 | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and Energy Schedule MW level before demand. |
| 5 | **Contact Path Operator (Control Area Operator)** | **Confirm** Energy Schedule Adjustment. |
| 6 | **End test** | **Upon** successful completion of Energy Schedule adjustment and confirmation of other Control Area operator. |
| 7 | **Record end time and MW level.** | **Test Sheet** – Record time (hr:mn:sc) and new Energy Schedule MW level. |
| 8 | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify** all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information). |

### 15.0.2. Response Test for Imported Regulation Services

| | | REGULATION RAMP RATE TEST |
|---|---|---|
| | STEP | INSTRUCTIONS FOR TEST ADMINISTRATOR (GENERATION DISPATCHER OR OTHER GRID OPS STAFF) |
| **1** | **Review A/S Certification Request and Testing Form** | **Confirm** (Mandatory-if not included, cancel test):<br>• Agency and phone number included.<br>• Resource ID included.<br>• All "Yes" boxes checked.<br>• Scheduled and approved by ISO Outage Coordination.<br>• Stated Values included in test data block. |
| **2** | **Confirm scheduled certification test** | **Contact** SC to clarify the schedule and nature of the tests to be performed. |
| **3** | **Review NERC Tag associated with A/S Schedule** | **If no tag:** Test result is fail.<br>**If tag:** Confirm Schedule amounts. |
| **4** | **Determine whether system conditions support test** | **Check** available internal resources to compensate for fluctuation of System Resource being tested. Final approval for testing must be obtained from the ISO Generation Dispatcher and Shift Manager. |
| **5** | **Position System Resource at start point for optimum response** | **Allow** enough room for ten minutes of ramping in the Stated Ramp Range. Preferably start at bottom or top of REGULATION range. |
| **6** | **Prepare System Resource** | **Assure:**<br>• System Resource on REGULATION.<br>• Unit blocks are clear from testing range.<br>• Host Control Area is prepared. |
| **7** | **Prepare EMS** | **Request** Alhambra to Assure:<br>• Control flag is on (REGULATION---see ACC Unit Summary).<br>• Reg limits are outside of testing range.<br>• "ISO Ramp Rate" is above Stated Ramp Rate (see AGC---ACC Unit Summary). |
| **8** | **Start test** | **Manually** replace Set Point to a level at least 10 times the Stated Ramp Rate above or below start point.<br>**(Start Time is the time that the Set Point is changed, as indicted on EMS or PI trend.)** |
| **9** | **Record start data** | **Request/Test Sheet –** Note time (hr:mn:sc) and MW level (recorded to one decimal place).<br>**Screen-print** – Capture MW level and start time. |
| **10** | **Monitor MW level** | **For** 10 minutes or until System Resource reaches upper or lower REGULATION limit. |
| **11** | **End test** | **After** 10 minutes or when System Resource reaches |

| | | |
|---|---|---|
| | | upper or lower REGULATION limit.<br>**ISO calls end of complete timed test.**<br>**SC calls end if limit is reached.** |
| **12** | **Record end time and MW level.** | **Screen-print** – Showing MW level and end time.<br>**Test Sheet** – Record time (hr:mn:sc) and MW level. |
| **13** | **Repeat test** | **Repeat** test if necessary. |
| **14** | **Additional Regulation testing** | **Range validation:** System Resource may be required to control across entire REGULATION range to verify the reliability of the upper and lower limits.<br>**Response time:** Note the length of time between Set Point change and System Resource response. This additional data will be used to evaluate the performance and reliability of the System Resource for Regulation. |
| **15** | **Follow-up** | **SLIC:** Log tests in SLIC, close out outage cards.<br>**Notify** all parties that testing is complete and systems should be returned to normal (including removal of Manual Replacement Values and artificial schedule information). |
| **16** | **Send Data to OSAT Test Administrator** | **A/S Certification Request and Testing Form:** Complete at least Test Administrator Name. Include any other recorded data.<br>**Screen-prints:** Sequence chronologically and note purpose of each screen-print. For example: "Begin Reg Up." |

## 16. CALCULATING TEST RESULTS

The processing of test data occurs, all or in part, after the testing procedure has been completed and may be performed by a party other than the OSAT Test Administrator and at a later time. The OSAT Test Administrator may send the documentation, including test forms and screen-prints, to the Data Manager or other personnel for some or all of the following steps:

| | | |
|---|---|---|
| **1** | **Calculate results** | Ramp rates and P-max/min levels are recorded to two decimal places.<br>**REFER TO DATA BLOCK ON A/S CERTIFICATION REQUEST AND TESTING FORM.**<br>**Complete:** "Start Time," "Start MW," "End Time," and "End MW" in the data block with data from the test screen-prints.<br>**Calculate results:** From data recorded in "Starting time," "Starting Point," "Ending Time," and "Ending point," calculate and indicate in "Certified Value".<br>**MW Change:** = {End MW – Start MW} (one decimal place). |

| | | |
|---|---|---|
| | | **MW Range**: indicates various test ranges (completed by SC).<br>**Stated P-max, P-min, or Ramp Rate:** (completed by SC).<br>**Certified P-max:** = lowest level during the 15 minute test period (tenths of a MW).<br>**Certified P-min: =** the highest level during the 15 minute test period (tenths of a MW).<br>**Certified Ramp Rate:** = {MW change/(End time – Start time*)} (two decimal places).<br>**Note for Regulation:** Symmetrical Reg Up and Reg Down values are necessary for proper operation of EMS. Therefore the single "Certified Value" for Reg will be the lesser of Reg Up and Reg Down.<br>*Convert seconds to hundredths of minutes by dividing seconds by 60. |
| **2** | **Organize documentation packet** | **Attach documents:** in the following order: |
| **3** | **Record data and results** | **In CERT data file –** The format and structure of the CERT data file is similar to the data blocks on the Request forms. The test data accumulated during testing along with the calculations performed above should be entered in the CERT data file exactly as on the Request forms. Note: The lesser of Reg Up and Reg Down ramp rates from the "Observed" field becomes the "Service Specific Certification" value for both.<br>**Certified Values –** The values derived from the tests and entered in the CERT data file, once approved by the Operations Engineer, are used as the certified values for bidding and validation. |
| **4** | **Archive Data** | **The OSAT Test Administrator** will file the data package in the particular file for the appropriate System Resource. |
| **5** | **Forward Data and Calculations to Client Representative** | **The OSAT Test Administrator** will notify the Client Representative of the CERT data file changes and additions. |

# 17. PROCESSING OF CERTIFICATION VALUES

## 17.0. Approval

### 17.0.1. Client Relations – Client Representative review data

Review Certification Data file test data for consistency with this procedure. Extract test data and calculations and send to Operations Engineer.

### 17.0.2. Operations Engineering and Maintenance – Operations Engineer review data

Evaluate test data and calculated certification values for reasonability and accuracy, and approve data to be used as Certified Values.

Forward Certified Values to Client Representative.

## 17.1. Master File Update

### 17.1.1. Client Relations – Client Representative enter change request

Enter a change request into the ISO's change management system to be routed to Market Operations for processing.

### 17.1.2. Market Operations – Master File Engineer update Master File

Coordinate with Market Participants and ISO Operations, enter the Certified Values into the ISO Master File, and notify the Client Representative of new data effective date.

## 17.2. Notification

### 17.2.1. Client Relations – Client Representative notifies SC

Notify SC of Master File update and effective date. Provide SC with appropriate certification documentation, including test data and calculations.

### 17.2.2. Client Relations – Client Representative notifies ISO Operations

Notify ISO Operations of new A/S resources.

# E

# EXCERPT FROM ERCOT PROTOCOLS ANCILLARY SERVICES

Excerpt from

# ERCOT Protocols

## Section 6: Ancillary Services

**June 1, 2001**

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Only sections of the ERCOT Protocols document are inserted here. For the full text of this document, go to www.ercot.com

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*Note the lighter text denotes the deleted sections of this document. See the title page for the source of the full text.*

# 6 ANCILLARY SERVICES

## 6.10 Ancillary Services Required by ERCOT

ERCOT shall be responsible for developing a daily Ancillary Services Plan with sufficient Ancillary Services (AS) to maintain the security and reliability of the ERCOT System consistent with ERCOT and North American Electric Reliability Council (NERC) standards. The Ancillary Services required by ERCOT are described below. ERCOT shall procure and deploy Ancillary Services on behalf of QSEs.

### *6.10.1 Balancing Energy Service*

**As provided by ERCOT to the Qualified Scheduling Entities (QSEs)**: Balancing Energy is deployed by ERCOT with the goals that (1) Regulation Service in either direction not be depleted during the interval, and (2) Regulation Service up and down energy is deployed in each Settlement Interval such that the net energy in regulation is minimized.

**As provided by a QSE to ERCOT**: The provision of incremental or decremental energy dispatched by Settlement Interval to meet the balancing needs of the ERCOT System.

### *6.10.2 Regulation Service –Down*

**As provided by ERCOT to the QSEs**: Regulation-down power is deployed in response to an increase in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

**As provided by a QSE to ERCOT**: The provision of Generation Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

### *6.10.3 Regulation Service-Up*

**As provided by ERCOT to the QSEs**: Regulation up power is deployed in response to a decrease in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

**As provided by a QSE to ERCOT**: The provision of Generation Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

### *6.10.4 Responsive Reserve Service*

**As provided by ERCOT to the QSEs**: Operating reserves ERCOT maintains to restore the frequency of the ERCOT System within the first few minutes of an event that causes a significant deviation from the standard frequency. Furthermore, Responsive Reserve Service provides reserved Resources that are deployed for the Operating Hour in compliance with these Protocols in response to loss-of-Resource contingencies on the ERCOT System.

**As provided by a QSE to ERCOT**: The provision of capacity by unloaded Generation Resources that are on line, Resources controlled by high set under-frequency relays or from Direct Current (DC) tie response. The amount of capacity from unloaded Generation Resources or DC Tie response is limited to the amount allowed in the Operating Guides or that which can be deployed within 15 seconds.

### *6.10.5 Non-Spinning Reserve Service*

**As provided by ERCOT to the QSEs**: Reserves maintained by ERCOT, that are deployed for the Operating Hour in response to loss-of-Resource contingencies on the ERCOT System.

**As provided by a QSE to ERCOT**: Off-line Generation Resource capacity, or reserved capacity from on-line Generation Resources, capable of being ramped to a specified output level within thirty (30) minutes or Loads acting as a Resource that are capable of being interrupted within thirty (30) minutes and that are capable of running (or being interrupted) at a specified output level for at least one (1) hour.

### *6.10.6 Replacement Reserve Service*

**As provided by ERCOT to the QSEs**: The instruction, by ERCOT, for the deployment of Loads or non-synchronized Generation Resources in order to make available additional Balancing Energy Service.

**As provided by a QSE to ERCOT**: A Resource capable of providing additional Balancing Energy Service to ERCOT when deployed.

### *6.10.7 Voltage Support*

**As provided by ERCOT to the QSEs**: The coordinated scheduling of voltage profiles at transmission busses to maintain transmission voltages on the ERCOT System in accordance with Operating Guides.

**As provided by a QSE to ERCOT**: The provision of Generation Resource capacity whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits throughout the ERCOT System in accordance with Operating Guides.

### *6.10.8 Black Start Service*

**As provided by ERCOT to QSEs**: The procurement by ERCOT through Agreements, pursuant to emergency dispatch by ERCOT and emergency restoration plans of Resources which are capable of self-starting without support from the ERCOT System in the event of a blackout, in order to begin restoration of the ERCOT System to a secure operating state.

**As provided by a Generator or a QSE to ERCOT**: The provision of Resources under a Black Start Agreement, pursuant to emergency dispatch, which are capable of self-starting without support from the ERCOT System in the event of a blackout.

### *6.10.9 Reliability Must-Run Service*

**As provided by ERCOT to QSEs**: Agreements for capacity and energy from units which otherwise would not operate and which are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria, as described in the Operating Guides, where Market Solutions do not exist.

**As provided by a QSE to ERCOT**: The provision of Generation Resource capacity and/or energy Resources under a Reliability Must-Run (RMR) Agreement, including Agreements with Synchronous Condenser Units, whose operation is directed by ERCOT.

### *6.10.10Out-Of-Merit Capacity Service*

**As provided by ERCOT to QSEs**: The provision by ERCOT of Out Of Merit Order (OOM) Replacement Reserve Service from Resources, or Loads acting as a Resource, that would otherwise not be selected to operate because of their place (or absence) in the Merit Order of Resources' bids for Ancillary Services. OOMC is used by ERCOT to provide for the availability of sufficient capacity so that Balancing Energy bids are available to solve capacity insufficiency, Congestion, or other reliability needs, when a Market Solution does not exist.

**As provided by a QSE to ERCOT**: Generation or Loads acting as a Resource capable of providing additional Balancing Energy Service to ERCOT when deployed.

### *6.10.11Out-Of-Merit Energy Service*

**As provided by ERCOT to QSEs**: The deployment by ERCOT for the Settlement Interval of energy from Resources, that may or may not have provided Resource specific premium bids, and used by ERCOT to provide Balancing Energy Service when no Market Solution exists for resolving Congestion or if required in declared emergencies as described in these Protocols.

**As provided by a QSE to ERCOT**: The provision of incremental or decremental energy dispatched from a specific Resource in emergency operations by Settlement Interval in Real Time to meet the balancing needs of the ERCOT System when no Market Solution exists or in declared emergencies.

## 6.11 Providers of Ancillary Services

### *6.11.1 Ancillary Services Provided Solely by ERCOT*

ERCOT is the sole provider of system-wide Balancing Energy Service; Generation Resource unit-specific Voltage Support Service (VSS), Black Start Service, Replacement Reserve Service, and RMR, OOMC and OOME Service to QSEs.

ERCOT will arrange Resources to provide system-wide VSS, Black Start and RMR Service from QSEs. ERCOT will direct Resources to provide OOMC or OOME in accordance with OOMC Service and OOME Service provisions of these Protocols.

### *6.11.2 Ancillary Services Provided in Part by ERCOT and in Part by Qualified Scheduling Entities*

Each QSE may self-arrange its obligation assigned by ERCOT for each of the following Ancillary Services: Regulation Up, Regulation Down, Responsive Reserve, and Non-Spinning Reserve. Any of the Ancillary Services that are not self-arranged will be procured as a service by ERCOT on behalf of the QSEs.

## 6.12 Responsibilities of ERCOT and Qualified Scheduling Entities

### *6.12.1 ERCOT Responsibilities*

(1) ERCOT through its Ancillary Service functions shall develop the Operating Day Ancillary Service Plan for the ERCOT System and allocate Ancillary Service obligations to individual QSEs. Unless otherwise provided in these Protocols, a QSE's allocation for Ancillary Services obligation will be determined for each hour according to that QSE's Load Ratio Share computation by ERCOT. The QSE Ancillary Service allocation shall be the hourly Load Ratio Share of the Load from the available settlement data, as defined in Section 9.2, Settlement Charges for the same hour and day of the prior week multiplied by the quantity of the service in the Operating Day AS Plan.

***PIP144: When system is assigned to LSE and then aggregating to the QSE Level, amend item #1 above with the following:***

(1) ERCOT through its Ancillary Service function shall develop the Operating Day Ancillary Service Plan for the ERCOT System and allocate Ancillary Service Obligations to individual LSEs, aggregated to the QSE level. Unless otherwise provide in these Protocols, a QSEs allocation for Ancillary Services obligation will be determined for each hour according to that LSE's Load Ratio Share computation by ERCOT. The LSE Ancillary Service allocation shall be the hourly Load Ratio Share of the Load from the available settlement data, as defined in Section 9.2, Settlement Charges, for the same hour and day of the prior week multiplied by the quantity of the service in the Operating Day AS Plan

(2) ERCOT shall procure required Ancillary Services not self-arranged by QSEs.

(3) ERCOT accepts Ancillary Service bids only from QSEs.

(4) ERCOT shall allow the same capacity to be bid as multiple Ancillary Services types recognizing that this capacity may only be selected for one service.

(5) ERCOT shall ensure provision of Ancillary Services to all ERCOT System Market Participants in accordance with these Protocols.

(6) ERCOT shall not discriminate when obtaining Ancillary Services from QSEs submitting Ancillary Service bids. ERCOT shall not discriminate between Self-Arranged Ancillary Services and ERCOT-procured Ancillary Services when dispatching Ancillary Services.

(7) For AS that are not self-arranged, ERCOT shall procure any additional Resources ERCOT requires during the Day-Ahead Scheduling Process, the Adjustment Period process, or the Operating Period.

(8) ERCOT shall procure Resources that are used to provide Reliability Must-Run Service or Black Start Service through longer-term Agreements.

(9) Following submission of QSE self-arranged schedules, ERCOT will identify the remaining amount of Ancillary Services that must be acquired in order to complete ERCOT's Day-Ahead Ancillary Services Plan. Regulation Up, Regulation Down, Responsive, and Non-Spinning services will be procured by ERCOT on the timeline described in Section 4, Scheduling.

(10) ERCOT will not profit financially from the market. ERCOT will follow the Protocols with respect to the procurement of Ancillary Services and will not otherwise take actions regarding Ancillary Services with the intent to influence, set or control market prices.

(11) ERCOT will provide that Market Clearing Prices are posted on the Market Information System (MIS) in a timely manner as stated in Section 12.4.1, Scheduling Information, of these Protocols. ERCOT will monitor Market Clearing Prices for errors and will "flag" for further review questionable prices before posting, and make adjustments or notations in the posting if there are conditions that cause the price to be questionable. ERCOT may only correct the price consistent with these Protocols.

(12) ERCOT shall post the aggregated ERCOT AS Bid Stacks in accordance with Section 12.4.2, Ancillary Service Related Information of these Protocols.

(13) ERCOT will, through procurement processes specified in these Protocols, procure Ancillary Services as required and charge QSEs for those Ancillary Services in accordance with these Protocols.

(14) ERCOT will ensure ERCOT electric network reliability and adequacy and will afford the market a reasonable opportunity to supply reliability solutions.

(15) ERCOT will not substitute one type of Ancillary Service for another.

(16) ERCOT shall strive to use Market Solutions to manage Congestion prior to using OOMC or RMR.

(17) ERCOT will make reasonable efforts to minimize the use of OOMC or contracted RMR Facilities.

(18) ERCOT will provide timely information to those Resource units providing OOMC and RMR services as to the specific use of each unit dispatched.

### *6.12.2 Qualified Scheduling Entity Responsibilities*

(1) Unless contracted otherwise, and with the exception of Balancing Energy decremental bids as described in Section 4, Scheduling, of these Protocols, Resources capable of providing Ancillary Services are not required to provide those Resources or to submit bids to ERCOT, provided, however, Resources shall honor bids submitted to ERCOT for Ancillary Services under these Protocols and shall, use reasonable efforts to provide Ancillary Services in accordance with applicable emergency procedures in these Protocols and in the Operating Guides.

(2) Ancillary Service providers shall provide and deploy, as directed by ERCOT, the Ancillary Service(s) that they have agreed to provide.

(3) QSEs may specify Self-Arranged Ancillary Services in accordance with the Day-Ahead Scheduling as described in Section 4.4, Day Ahead Scheduling Process.

***[PIP 106: Current design does not provide for DLC Profiles. When DLC Profiles are implemented add this item (4) to section 6.3.2 ]***

(4) QSEs that have Direct Load Control programs as described in Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control, will notify ERCOT immediately of any deployment of the program. This applies solely to QSEs using Load Profiling for Settlement.

## 6.13 Standards and Determination of the Control Area Requirements for Ancillary Services

### *6.13.1 Standards for Determining Ancillary Services Quantities*

(1) ERCOT shall comply with the requirements for determination of Ancillary Service quantities as specified in these Protocols and the Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the minimum quantity requirements for each Ancillary Service needed for reliability.

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements.

(4) If ERCOT determines a need for additional Ancillary Service Resources pursuant to these Protocols or the Operating Guides, after an Ancillary Services Plan for a specified day has been posted, ERCOT will inform the market by posting on the Market Information System, of ERCOT’s intent to procure additional Ancillary Service Resources in accordance with Section 4.5.8, ERCOT Notice to Procure

Additional Ancillary Services. ERCOT will post the reliability reason for the increase in service requirements.

(5) Once specified by ERCOT for an hourly interval, Ancillary Service quantity requirements may not be decreased.

(6) ERCOT shall instruct such that sufficient Resource capacity is on line, in appropriate locations, and available to ERCOT to meet the potential needs of the ERCOT System.

(7) ERCOT shall include in its AS plan sufficient capacity to automatically control frequency to meet NERC standards.

(8) ERCOT will post Engineering Studies on the MIS representing specific Ancillary Service requirements as described in Section 12, ERCOT Market Information System.

### *6.13.2 Determination of ERCOT Control Area Requirements*

By the 20th day of the current month, ERCOT will post a forecast of minimum Ancillary Services quantity requirements for the next calendar month.

Prior to 0600 of the Day Ahead, ERCOT will use the Day-Ahead Load forecast and will develop an Ancillary Services Plan that identifies the amount of Ancillary Services necessary for each hour of the next day as specified in Section 4, Scheduling. The amount of Ancillary Services required may vary depending on ERCOT System conditions from hour to hour.

By 0600 of the Day Ahead, ERCOT will post an ERCOT System and zonal Load forecast for the next seven (7) days, by hour. ERCOT will notify each QSE of its allocated share of Ancillary Services for each hour for the next day, as specified in Section 4, Scheduling. ERCOT will make available to Market Participants any ERCOT area Load forecasts used in the determination of its ERCOT System and zonal forecasts.

***PIP134: There are concerns that w/o using the Messaging System, the information is susceptible to screen scrapes. Once the system uses the Messaging System. The first sentence of the paragraph above should be replaced as follows:***

By 0600 of the Day Ahead, ERCOT will post an ERCOT System and zonal Load forecast for the next seven (7) days, by hour using the Messaging System.

ERCOT will determine the total required amount of each Ancillary Service using the Operating Guides and the following:

(1) Balancing Energy Service: ERCOT will estimate Balancing Energy needs based on the actual Load, the difference in forecasted Loads and Loads reported in bilateral schedules, deployed Regulation Service, and forecasted Congestion.

(2) Regulation Service: ERCOT will use its operational judgment and experience to determine the quantity of Regulation-Up and Regulation-Down procured. The quantity of Regulation-Up may differ from the quantity of Regulation-Down in any particular hour.

(3) Responsive Reserve Service: The requirement for Responsive Reserves is specified in the Operating Guides. Using ERCOT-approved procedures ERCOT may increase the quantity requirement based on its judgment of reliability conditions.

(4) Non-Spinning Reserve Service: ERCOT will use its operational judgment and experience to determine the quantity of Non-Spinning Reserves procured.

(5) Replacement Reserve Service: Replacement Reserves are procured from Generation Resource units planned to be off-line and Load acting as a Resource that are available for interruption during the period of requirement. Energy is deployed from these procured Resources by requiring them to bid into the Balancing Energy market. ERCOT will consider the Generation Resource capacity on line, based on Resource Plans, in its determination of Zonal Congestion and Local Congestion requirements. ERCOT will evaluate the need for Replacement Reserves necessary to correct for ERCOT total capacity insufficiency, Zonal Congestion, or Local Congestion. ERCOT shall determine the amount of RPRS to provide sufficient capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides, given ERCOT forecasted Load conditions as posted on the Market Information System.

(6) Voltage Support: ERCOT in coordination with the TDSPs shall conduct studies to determine the normally desired Voltage Profile for all Generation Resource busses in the ERCOT System and shall post all Voltage Profiles on the Market Information System. ERCOT may temporarily modify its requirements based on current system conditions. ERCOT shall determine the amount of Voltage Support Service needed to provide sufficient reactive capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides.

(7) Black Start Service: ERCOT shall periodically determine and review the location and number of Black Start Resources required as well as special transmission needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC policy.

## 6.14 Technical Requirements for Providers of Ancillary Services

Providers of Ancillary Services shall meet the general requirements specified in the subsection 6.5.1, General Technical Requirements below as well as the requirements of the specific Ancillary Service being provided, as described in Sections 6.5.2, Balancing Energy Service through 6.5.10, Out of Merit Capacity and Out of Merit Energy Services.

### *6.14.1 General Technical Requirements*

Providers of Ancillary Services shall meet the following general requirements.

#### 6.14.1.1 Requirement for Operating Period Data for System Reliability and Ancillary Service Provision

Operating Period data will be used by ERCOT to monitor the Real Time reliability of the ERCOT System, and will be used in network analysis software to predict the short-term reliability of the ERCOT System. Each TDSP, at its own expense, may obtain such Operating Period data from ERCOT or from QSEs.

(1) A QSE representing a Generation Entity that has Generation Resources connected to a TDSP shall provide the following Real Time data to ERCOT for each individual generating unit at a Generation Resource plant location and ERCOT will make the data available to the Generation Resource's host TDSP (at TDSP expense):

(a) Gross or net real power,

(b) Gross or net reactive power,

(c) If gross quantities are provided, the plant auxiliary Load data will also be supplied,

(d) Status of switching devices in the plant switchyard not monitored by the TDSP affecting flows on the ERCOT System,

(e) Frequency bias of portfolio Generation Resources under QSE operation,

(f) Any data mutually agreed by ERCOT and the QSE to adequately manage system reliability,

(g) Generator breaker status,

(h) High Operating Limit, and

(i) Low Operating Limit.

(2) Any QSE providing Responsive Reserve and/or Regulation must provide for communications equipment to receive ERCOT telemetered control deployments of service power.

(3) Any QSE providing Regulation Service must provide appropriate Real Time feedback signals to report the control actions allocated to the QSEs Generation Resources.

(4) Any QSE that represents a provider of Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve using Load as a Resource shall provide separate telemetry of the real power consumption of each Load providing the above Ancillary Services and the status of the breaker controlling that Load. If Load is used as a Responsive Reserve Resource, the status of the high-set under frequency relay will also be telemetered.

(5) Real Time data for reliability purposes must be accurate to within three percent (3%). This telemetry may be provided from relaying accuracy instrumentation transformers.

***PIP 112: Inset #5 below when BUL is implemented***

(5) Any QSE that represents a qualified provider of Balancing Up - Load (BUL) need not provide telemetry but rather shall provide an estimate in real-time representing the real power interrupted in response to the deployment of Balancing Up Load (BUL).

(6) Real Time data for reliability purposes must be accurate to within three percent (3%). This telemetry may be provided from relaying accuracy instrumentation transformers.

### *6.14.2 Balancing Energy Service*

The Balancing Energy Service bids shall consist of Balancing Energy Service Up and Balancing Energy Service Down bids. All Balancing Energy Service provider bids must be entered by the close of the Adjustment Period for the effective Operating Hour and shall become an obligation at the close of the Adjustment Period. However, Balancing Energy Service provider bids may be withdrawn at any time prior to the close of the Adjustment Period.

Beginning on June 1, 2001, and continuing thereafter until July 4, 2003, Balancing Energy Service bids shall be capped at $1,000 per MWh. This limitation will not apply to Loads acting as Resources or BULs.

(1) Balancing Energy Service bids must specify Congestion Zone, a ramp rate, and service time period. Balancing energy service up bids consist of monotonically increasing ordered pairs ($/MWh, MW). Balancing energy service down bids consist of monotonically decreasing ordered pairs ($/MWh, MW).

***PIP112: Replace beginning paragraph and item 1 above with the following when BUL is implemented:***

The Balancing Energy Service bids shall consist of Balancing Energy Service Up, Balancing Energy Service Down, and Balancing Up - Load bids. All Balancing Energy Service provider bids must be entered by the close of the Adjustment Period for the effective Operating Hour and shall become an obligation at the close of the Adjustment Period. However, Balancing Energy Service provider bids may be withdrawn at any time prior to the close of the Adjustment Period.

(1) Balancing Energy Service bids must specify Congestion Zone, the type of bid, either a Resource or a BUL used to deploy the service, a ramp rate, and service time period.

(a) For Balancing Energy Service Up and Balancing Energy Service down, the bid curve consists of monotonically increasing ordered pairs of dollars per megawatt hour and cumulative megawatts ($/MWh, MW).

(b) For Balancing Up – Load, the bids consist of blocks in dollars per megawatt hour and megawatts ($/MWh, MW). If the full block cannot be deployed the bid will be bypassed.

(2) QSEs shall provide Balancing Energy Down Service bids prior to the close of the Adjustment Period equal to or greater than ERCOT posted percentage at 0600 of the Day Ahead according to Section 4.4.5, Notification to QSEs of Mandatory Balancing Energy Service Down Bid Percentage Requirements and Section 4.5.2, Receipt of QSE's Balancing Energy Bid Curves.

(3) ERCOT shall order all bids received for Balancing Energy Service Up from lowest bid price to highest bid price. ERCOT will determine the total amount of energy bid in the stack available in sixty (60) minutes.

***PIP112: Replace item #3 above when BUL is implemented:***

(3) ERCOT shall order all bids received for Balancing Energy Service Up and Balancing Up – Load together from lowest bid price to highest bid price. This combination shall be the Balancing Energy Service Up bid stack. ERCOT will determine the total amount of energy bid in the stack available in sixty (60) minutes.

(4) ERCOT will determine the required amount of Balancing Energy Service such that Regulation Service Up energy and Regulation Service Down energy is provided in each Settlement Interval.

(5) ERCOT will plan to deploy Balancing Energy Service in each Settlement Interval in a manner that will minimize total net energy from Regulation Service.

(6) The Balancing Energy Service deployment will be in megawatts. The Balancing Energy obligation shall be the power requested integrated over the interval considering ramping specifications in the QSE's bid.

(7) Balancing Energy Service may only be deployed in the Operating Period. ERCOT's selection of energy from Ancillary Service Resources for deployment shall be based on the price Merit Order of bids received and bid ramp rate and not on the expected MCPE. The ERCOT System Operator making Balancing Energy Service decisions shall not have access to the individual Balancing Energy Service bid prices or the expected MCPE.

(8) If the Balancing Energy Service Up Bid Stack does not overlap with the Balancing Energy Service Down Bid Stack, and ERCOT is using Balancing Energy Service Up and needs a lesser amount of Balancing Energy, ERCOT must first recall any Balancing Energy Service Up prior to deploying any Balancing Energy Service Down, unless resolving Local Congestion.

(9) If the Balancing Energy Up bid prices are lower than Balancing Energy Down bid prices, also known as overlap, and deployment required of Balancing Energy Service would result in an MCPE within the overlap then, the Balancing Energy Up and Balancing Energy Down or a portion of each are deployed, unless resolving Local Congestion.

(10) If ERCOT is using Balancing Energy Service Down and needs a greater amount of Balancing Energy, ERCOT must first recall any Balancing Energy Service Down prior to deploying any Balancing Energy Service Up, subject to this subsection.

(11) If ERCOT is using Balancing Energy Service Up and needs a lesser amount of Balancing Energy, ERCOT must first recall any Balancing Energy Service Up prior to deploying any Balancing Energy Service Down, subject to this subsection.

(12) Balancing Energy Service Up and Down shall not be deployed in the same Settlement Interval in the same Congestion Zone, unless clearing an overlap in the Balancing Energy Service Up and Balancing Energy Down bid prices, or solving Local Congestion.

(13) ERCOT shall provide ten (10) minutes notice to the QSEs providing Balancing Energy Service Up or Balancing Energy Service Down to change deployment via the Messaging System.

(14) ERCOT shall provide notice electronically via the Messaging System to each QSE with the number of megawatts expected to be delivered as a result of Balancing Energy Service Dispatch Instructions.

(15) Loads acting as a Resource and providing Balancing Energy Service must be capable of responding to ERCOT Dispatch Instructions in a similar manner to Generation Resources.

***PIP112: Replace items #14 and 15 above with the following when BUL is implemented***

(14) ERCOT shall provide notice electronically via the Messaging System to each QSE with the number of megawatts expected to be delivered as a result of Balancing Energy Service Dispatch Instructions. The Messaging System will identify requests for Balancing Up – Load.

(15) Loads acting as a Resource and providing Balancing Energy Service must be capable of responding to ERCOT Dispatch Instructions in a similar

manner to Generation Resources. BUL is not considered to be a Load acting as a Resource.

(16) The deployment of power shall be constrained by the bidders' specified ramp rate except during EECP Operations.

(17) QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by ramping during a fixed ramp period starting five (5) minutes prior to the target service interval. Energy provided outside of the target Settlement Interval as a result of ramping at the specified rate will not be considered part of the Dispatch Instruction.

**[PIP110:** ***Ramp rates are included in the P1 interface view for Balancing Energy Instructed Deployments. The interface data point is only the Cleared MW amount. The Ramp Rate Limit and Ramp Rate Actual are defined in the interface view; however, the approach for including the ramp rate in the energy instruction has not been defined. Once the system is modified to include ramp rates as part of the Dispatch Instructions, item #17 above will be replaced with the following:]***

(17) QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by ramping at the QSE specified ramp rate starting five (5) minutes prior to the target service interval. Energy provided outside of the target Settlement Interval as a result of ramping at the specified rate will be considered an instructed deviation.

(18) Balancing Energy Service deployment instructions by ERCOT to any QSE are constrained by the amount of power that can be deployed in fifteen (15) minutes at the QSE specified ramp rate in the QSE's bid.

(19) Balancing Energy Service recall instructions by ERCOT are not constrained by the QSE specified ramp rate. However, the QSE is expected to recall those instructions at a fixed ramp period. Energy provided outside of the target settlement interval as a result of the ramping specified above will not be considered part of the Dispatch Instruction

**PIP110:** ***Once the system is modified to include ramp rates as part of the Dispatch Instructions, item #19 above will be replaced with the following:***

(19) Balancing Energy Service recall instructions by ERCOT are not constrained by the QSE specified ramp rate. However, the QSE is expected to recall those instructions at the specified ramp rate. Energy provided outside of the target settlement interval as a result of the ramping specified above will be considered instructed deviation.

(20) ERCOT shall not use Loads acting as a Resource qualified to provide Balancing Energy Service under the OOME instructions and pricing structure.

***PIP112: Replace items #17 through #20 with the following once BUL is implemented:***

(17) With the exception of Balancing Up – Load, QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by ramping at the QSE specified ramp rate starting five (5) minutes prior to the target service interval. For Balancing Up – Load, QSEs are expected to comply with Balancing Energy Service Dispatch Instructions by interrupting load as close to the target interval as possible. Energy provided outside of the target Settlement Interval as a result of ramping at the specified rate will be considered an instructed deviation.

(18) With the exception of Balancing Up - Load, Balancing Energy Service deployment instructions by ERCOT to any QSE are constrained by the amount of power that can be deployed in fifteen (15) minutes at the QSE specified ramp rate in the QSE's bid. Deployment instructions for Balancing Up - Load are constrained by the amount of the block bid.

(19) Balancing Energy Service recall instructions by ERCOT are not constrained by the QSE specified ramp rate. However, the QSE is expected to recall those instructions at the specified ramp rate. Energy provided outside of the target settlement interval as a result of the ramping specified above will be considered instructed deviation.

(20) Loads acting as Resources qualified to provide Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve Services may also be used by ERCOT to provide Balancing Energy under the OOME instructions and pricing structure. ERCOT shall not use Loads qualified to provide only Balancing Up Load Service under the OOME instructions and pricing structure.

**[PIP119:** ***The calculation for OOME only takes instructions to generators into account. There is no provision for Loads acting as Resource in the OOME market. Once LaaR can be taken into account, item 20 above should added above]***

(21) The minimum number of megawatts of Balancing Energy Service that may be offered to ERCOT is one (1) MW.

### *6.14.3 Regulation Service (RGS)*

(1) The QSE's control system must be capable of receiving digital control signals from ERCOT's control system, and of directing its units to respond to the control signals, in an upward and downward direction to balance Real Time demand and Resources, consistent with established NERC and ERCOT operating criteria.

(2) Any QSE providing RGS must provide for communications equipment to receive telemetered control deployments of power from ERCOT.

(3) QSEs must demonstrate to ERCOT that they have the capability to switch control to constant frequency operation as specified in the Operating Guides using telemetry at the QSE's control center. ERCOT authorized operations of the QSEs regulation control system on constant frequency will be considered a Dispatch Instruction to deviate from schedule energy.

(4) QSEs providing RGS will be required to provide a feedback signal meeting the requirements of ERCOT.

(5) The Resource providing RGS must be capable of delivering the full amount of regulating capacity offered to ERCOT within ten (10) minutes.

(6) The minimum amount of RGS that may be offered to ERCOT is one (1) MW.

(7) QSE's bids will be in accordance with Section 4, Scheduling.

(8) Regulation instructions will be included in a QSEs SCE calculation as instructed deviations.

(9) Each Generation Resource providing RGS must meet additional technical requirements specified in Section 6.10 Ancillary Service Qualification, Testing and Performance Standards of these Protocols.

(10) Generation Resources providing RGS must have their governors in service.

(11) RGS is deployed proportionately to all providers.

(12) Resources providing RGS must have sufficient qualified Generation Resources that will be online and able to respond in the Operating Hour for which they have been selected to provide the Ancillary Service.

### *6.14.4 Responsive Reserve Service*

(1) Responsive Reserve Service (RRS) may be provided by: (a) unloaded Generation Resources that are on-line, (b) Resources controlled by high-set under-frequency relays, (c) hydro Responsive Reserves, or, (d) from DC Tie response that stops frequency decay. The minimum amount of RRS provided by Generation Resources shall be as specified in the Operating Guides. QSE's Generation Resources providing RRS must be on-line and capable of ramping to the awarded output level within ten (10) minutes of the notice to deploy energy, must be immediately responsive to system frequency, and must be able to maintain the scheduled level for the period of service commitment. The amount of RRS on an individual Generation Resource may be further limited by requirements of the Operating Guides.

(2) A QSE's Load acting as a Resource must be loaded and capable of unloading the scheduled amount of RRS within ten (10) minutes of instruction by ERCOT and by action of underfrequency relays as specified by the Operating Guides.

(3) Any QSE providing RRS must provide communications equipment to receive ERCOT telemetered control deployments of power.

(4) Generation Resources providing RRS must have their governors in service.

(5) Loads Acting as a Resource providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.

(6) The minimum amount of RRS that may be offered to ERCOT is one (1) MW.

(7) QSEs that provide the Resource for Responsive Reserve Service must ensure that Resources providing the service must be able to respond in the Operating Hour for which they have been selected to provide the RRS. Each Generation Resource and Load acting as a Resource and providing RRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards of these Protocols.

(8) The amount of Resources on high-set under-frequency relays providing RRS will be limited as prescribed in the Operating Guides.

(9) QSE bids for RRS will be in accordance with Section 4, Scheduling.

### *6.14.5 Non-Spinning Reserve Service (NSRS)*

(1) NSRS providers must be capable of being synchronized and ramped to their bid-specified output level within thirty (30) minutes. NSRS can be provided from unloaded on-line capacity that can ramp within thirty (30) minutes or Load acting as a Resource that is capable of unloading within thirty (30) minutes and that is not fulfilling any other commitment from the capacity, including participation in ERCOT markets, self-generation, or other energy transactions.

(2) Loads providing NSRS must provide a telemetered output signal, including breaker status.

(3) The minimum amount of NSRS that may be offered to ERCOT is one (1) MW.

(4) Each Generation Resource and Load acting as a Resource and providing NSRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification Testing and Performance.

(5) QSEs using Loads to provide NSRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide NSRS.

(6) Resources providing NSRS must be able to respond in the hours for which they have been scheduled to provide the Ancillary Service.

(7) QSE bids for NSRS will be submitted in accordance with Section 4, Scheduling.

### *6.14.6 Replacement Reserve Service*

(1) Replacement Reserve Service (RPRS) is provided by Resources that may otherwise be unavailable to ERCOT in the hours that ERCOT requests RPRS. These Resources may include Generation Resources that are expected to be off-line in the requested hours and Loads acting as a Resource that otherwise may be unavailable to be dispatched by ERCOT, i.e. Loads not declared as an active Resource in the Resource Plan at the time of the RPRS procurement.

(2) Resources providing RPRS must provide a telemetered output signal, including breaker status.

(3) The minimum amount of RPRS that may be offered to ERCOT is one (1) MW.

(4) Resources eligible to bid must meet additional technical requirements specified in Operating Guides

(5) There may only be one RPRS bid from any given Resource.

(6) Generation Resource and Loads acting as a Resource accepted for RPRS must be able to respond in the hours for which they have been selected to provide the Ancillary Service.

(7) QSEs using Loads to provide RPRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resources to provide RPRS.

(8) Each Generation Resource and Load acting as a Resource providing RPRS must meet additional technical requirements specified in the Ancillary Service Qualification, Testing and Performance Standards, 6.10. QSEs must comply with their Balanced Schedule despite any generation provided by the RPRS unit. For example, the QSE supplying RPRS must adjust other Resources to accommodate the minimum operating output of the RPRS Resource selected by ERCOT in order to comply with their Balanced Schedule and Dispatch Instructions.

(9) QSE bids for RPRS will be in accordance with Section 4, Scheduling.

(10) RPRS may not be self-arranged by the QSE.

### *6.14.7 Voltage Support Service*

(1) A QSE's Generation Resource is expected to operate within the reactive power capability requirements specified in these Protocols and the Operating Guides.

(2) A QSE's Generation Resource must be capable of maintaining a Voltage Profile limited to the quantity of Reactive Power the Generation Resource can produce at rated capability, (MW), and a power factor of .95 leading or lagging measured at the unit main transformer high voltage terminals. This quantity of Reactive Power is the Unit Reactive Limit (URL).

(3) Qualified renewable generators (as described in Section 14, Renewable Energy Credit Trading Program) and Generation Resources in operation prior to September 1, 1999 whose current design does not allow them to meet the URL as stated above, will be required to maintain a Voltage Profile that is limited to the quantity of reactive power that the Generation Resource can produce at it's rated capability (MW) using procedures and criteria as described in the Operating Guides.

(4) A QSE's Generation Resource is expected to be compliant with the Operating Guides for response to transient voltage disturbance.

(5) Each Generation Resource providing Voltage Support Service must meet technical requirements specified in the Ancillary Service Qualification, Testing and Performance Standards section of these Protocols, Section 6.10.

(6) ERCOT shall establish, and update as necessary, Voltage Profiles at points of interconnection of Generation Resources to maintain system voltages within established limits

(7) ERCOT shall communicate to the QSE the desired voltage at the point of generation interconnection by providing Voltage Profiles.

(8) ERCOT shall deploy static Reactive Power Resources as required to continuously maintain dynamic Reactive Reserves from QSEs, both leading and lagging, adequate to meet ERCOT System requirements.

(9) A QSE's Generation Resource shall operate with the unit's automatic voltage regulator (AVR) in use unless specifically directed to operate in manual mode by ERCOT, or unless the QSE determines a need to operate in manual in emergency conditions. When the QSE changes the mode, the QSE shall promptly inform ERCOT. Any QSE-controlled power system stabilizers will be kept in service whenever possible. QSEs' control centers will monitor the status of their regulators and stabilizers.

(10) QSEs shall meet, within established tolerances, and respond to changes in the Voltage Profile established by ERCOT subject to the stated QSE Reactive Power and actual power operating characteristic limits and voltage limits.

### *6.14.8 Black Start Service*

(1) Providers of Black Start Service shall meet the requirements specified in NERC policy.

(2) Each Resource providing Black Start Service must meet technical requirements specified in the Ancillary Services Qualification, Testing and Performance Standards section of Section 6.10.

(3) Beginning in 2001, ERCOT will request bids from Generation Resource Entities for the provision of Black Start Service. Such bids shall be due on or before

October 1, of each year. Bids will be evaluated and contracted by December 31 for the following calendar year. ERCOT shall ensure Black Start Services are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a total or partial system blackout.

(4) ERCOT shall schedule random testing or simulation, or both, to verify Black Start Service is operable according to the ERCOT System restoration plan. Testing and verification will be in accordance with established qualification criteria

(5) QSEs representing Generation Resources contracting for Black Start Services shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically conduct system restoration seminars for all TDSPs, QSEs, Generation Entities and other Market Participants.

### *6.14.9 Reliability Must-Run Service*

(1) ERCOT shall follow published procedures when scheduling RMR Units and make available through posting on the MIS all studies supporting the need for declaring units as RMR Units. ERCOT should make every attempt to minimize the use of RMR Facilities. ERCOT should have the right to dispatch an RMR Unit at any time for transmission reliability. ERCOT will dispatch the unit as early as possible once conditions are identified that require the use of the RMR Facility, as defined in Section 4, Scheduling and the RMR Agreement.

(2) Each RMR Unit providing Reliability Must Run Service must meet technical requirements specified in Section 6.10 Ancillary Services Qualification, Testing and Performance Standards.

(3) RMR Service is a contracted service between the owners or operators of Generation Resources and ERCOT. Any multi-year Agreement must be approved by the ERCOT Board prior to execution of the Agreement. An RMR Standard Agreement is included in Section 22, Protocols Agreements.

(4) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability. A Generation Entity can only obtain RMR Agreements where necessary to ensure ERCOT System reliability according to the Operating Guides.

(5) A Generation Resource cannot be compelled to enter into an RMR Agreement. Owners of Generation Resources that are uneconomic to remain in service can voluntarily petition ERCOT for contracted RMR status. ERCOT will be required to attest as to whether the unit is necessary for system reliability based on a defined set of planning criteria established in the Operating Guides. If ERCOT determines that the nominated unit is required for system reliability, the Generation Entity may request ERCOT to allow operation as a Synchronous Condenser in place of RMR operation. If Synchronous Condenser operation is offered by the Generation Entity, ERCOT shall accept Synchronous Condenser

operation unless ERCOT reasonably determines that a Synchronous Condenser operation is not adequate to meet System Reliability according to the Operating Guides.

(6) ERCOT must acquire the entire capacity of each RMR Unit.

(7) RMR Units may not participate in the bilateral capacity and energy markets, including Self-Arranged Ancillary Services. RMR Units may participate in the Balancing Energy market during times when ERCOT has requested the unit to run at less than full capacity. ERCOT may dispatch an RMR Unit prior to procuring OOMC or OOME services on other units provided the time of use constraints of the RMR Unit are maintained.

(8) RMR Units are dispatched by ERCOT only when necessary to provide ERCOT System security, including any emergency situation.

(9) ERCOT will treat the undeployed energy from RMR Units like any other unit for purposes of Balancing Energy Service Up provided the time of use constraints of the RMR Unit are maintained.

(10) ERCOT will administer RMR Agreements in such a way as to minimize the use of RMR Units as much as practicable. ERCOT will provide to all Market Participants all information relative to the use of RMR including energy deployed.

(11) Entity may not use the RMR Unit for:

(a) Participation in the bilateral energy market;

(b) Self-provision of energy except for plant auxiliary Load obligations under the RMR Agreement;

(c) Provision of Self Arranged Ancillary Services to any Entity;

(d) Ancillary Services markets, except for incremental bids into the Balancing Energy Services market to the extent allowed in the RMR Agreement.

### *6.14.10Out-Of-Merit Capacity and Out- of-Merit Energy Services*

(1) ERCOT will use OOMC and OOME Services to procure additional capacity and energy required to provide reliable ERCOT System operation, as determined by ERCOT.

(2) Any Generation Resource or Load acting as a Resource may be called upon by ERCOT to provide OOMC or OOME service, in any time frame that the Resource or Load is listed as available in the Resource Plan.

(3) OOMC is used by ERCOT only when necessary to provide ERCOT System security and capacity adequacy. ERCOT will call on OOMC and OOME service in such a way as to minimize the use of this service as much as practicable.

(4) OOME will be settled in accordance with Balancing Energy settlement provisions in Section 9, Settlement and Billing.

(5) Bids from Loads acting as Resources may also be used by ERCOT under the OOME instructions and pricing structure.

(6) The QSE associated with the Generation Resource or Load acting as a Resource that receives a Dispatch Instruction to provide OOMC and/or OOME service(s) must use all commercially reasonable efforts to provide the requested service(s). If the QSE declines the Dispatch Instruction according provisions of Section 5.4.4, Compliance with Dispatch Instructions, of these Protocols to provide OOMC and/or OOME service(s), ERCOT will post such declines on the MIS.

## 6.15 Selection Methodology

### *6.15.1 Qualified Scheduling Entity Rights and Obligations to Self-Arrange Ancillary Service Resources*

(1) QSEs may self-arrange only Regulation Up, Regulation Down, Responsive Reserve Services, and Non-Spinning Reserve Services.

(2) A QSE may self-arrange Resources by indicating the amount of each Ancillary Services that will be self-arranged in each hour of the Operating Day.

(3) The quantity self-arranged specified by a QSE at 1100 in the Day Ahead shall not be changed for the Day Ahead obligation, unless ERCOT allows schedules to be updated at 1300 in accordance with Section 4.4.10, QSE Submittal of Updated Balancing Energy Schedules.

(4) The quantity of Self-Arranged AS specified by a QSE in response to a notice by ERCOT to obtain additional AS in the Adjustment Period cannot be greater than the allocated additional AS amount and cannot be changed once committed to ERCOT.

(5) QSEs may schedule with ERCOT to provide Ancillary Services on another QSE’s behalf by notifying ERCOT consistent with the requirements of Section 4, Scheduling.

### *6.15.2 Competitive Procurement of Ancillary Service Resources by ERCOT*

(1) Except where stated to the contrary in these Protocols, ERCOT shall, to the extent the Ancillary Service Resource bids are available, use competitive procurement processes to procure sufficient Ancillary Service Resources to meet the requirements specified in these Protocols.

(2) QSEs may submit bids to provide Regulation Down, Regulation Up, Responsive Reserves, and Non-Spinning Reserves, as part of the Scheduling Process in accordance with Section 4, Scheduling.

(3) QSEs offering Balancing Energy Up, Balancing Energy Down, and Replacement Reserves can offer bids through the Adjustment Period, in accordance with Section 4.5, Adjustment Period Scheduling Process.

(4) QSE's bids to provide Ancillary Services will continue to be valid until withdrawn by the QSE prior to the market clearing or the market is cleared. Bids may not be withdrawn during bid evaluation by ERCOT as described in Scheduling Sections 4.4 Day Ahead Scheduling Process and Section 4.5Adjustment Period Scheduling Process or after the bid is selected.

(5) QSEs may only submit bids from that portion of any Resource not used to provide capacity and energy to supply the Resources in the QSE's Balanced Schedule.

(6) Other than as specified for Congestion Management, ERCOT shall select Ancillary Services capacity based on the lowest Ancillary Service bids, including capacity bids for RGS Up, RGS Down, RRS, NSRS, and RPRS. For each of RGS Up, RGS Down, RRS, NSRS and RPRS, ERCOT will determine a MCPC for each settlement period as specified in Section 6.6 Selection Methodology.

(7) Other than as specified for Congestion Management, ERCOT shall dispatch energy from the Balancing Energy Service bids based on price Merit Order and the requirements specified in Section 5, Dispatch Instructions.

(8) For Congestion Management, ERCOT shall, if possible, resolve all Congestion using the Balancing Energy Service by Congestion Zone.

(9) ERCOT shall establish, through a competitive procurement process, long-term agreements with Resources needed to provide Black Start capability.

### *6.15.3 ERCOT Day-Ahead Ancillary Service Procurement Process*

#### 6.15.3.1 General Procurement Requirements

(1) ERCOT shall conduct daily the Day Ahead bidding process for the purpose of procuring the quantities of Resources as specified in the Ancillary Services plan for all Operating Hours of the next Operating Day to provide Regulation Up, Regulation Down, Responsive Reserves, and Non-Spinning Reserves.

(2) ERCOT shall procure Resources in the Day-Ahead market sequentially for each hour of the next Operating Day, in the following order: Regulation – Down, Regulation – Up, Responsive Reserves, and Non-Spinning Reserves. ERCOT will also procure Replacement Reserves, if needed,

prior to the end of the Day Ahead market, in accordance with Section 4.4.19 Decision to Extend Day-Ahead Scheduling Process to Two-Day-Ahead Scheduling Process.

(3) ERCOT will procure the amount of each service specified in the Ancillary Service Plan, less the amount self-arranged, without substituting one service for a different service.

(4) A QSE may offer the same Resource capacity into any or all of the Ancillary Services markets simultaneously. A QSE may specify different capacity bids from a single Resource for each of the Ancillary Service markets into which the Resource is bid in compliance with Section 4, Scheduling.

(5) For each Ancillary Service procurement process, ERCOT shall select capacity bids submitted by QSEs, such that:

(a) After adjusting for self-arranged Resources, the total amount of capacity procured by ERCOT meets the Ancillary Services Plan requirements;

(b) For each of RGS Up, RGS Down, RRS, and NSRS, bids will be arranged in ascending order by price in a Bid Stack. For each of these Ancillary Services, ERCOT will procure required quantities by selecting capacity in ascending order starting from the lowest priced bid. ERCOT will continue this selection process to obtain the required quantity of each of these Ancillary Services. For each Ancillary Service, if selection of the marginal capacity block will exceed ERCOT's required Ancillary Service quantity, ERCOT will select a portion of this capacity block as the actual marginal AS quantity accepted.

(c) In the case where multiple bids have the same price for the selection of RGS Up, RGS Down, RRS and NSRS Ancillary Services, selection shall be awarded proportionately.

(6) ERCOT shall deduct any Resource capacity accepted in one of the Ancillary Service procurement auctions from the capacity that is available for procurement in the subsequent Ancillary Service procurement auction if the QSE has indicated that the Resource capacity bids are linked.

(7) ERCOT shall determine an hourly MCPC for each of the following Day-Ahead Ancillary Service markets: Regulation Up, Regulation Down, Responsive Reserves and Non-Spinning Reserves. The hourly MCPC shall equal the highest-priced capacity reservation bid accepted by ERCOT for that Ancillary Service for the hour.

(8) If the MCPC cannot be calculated by ERCOT, the MCPC for the particular Ancillary Service shall be deemed to be equal to the MCPC for

that Ancillary Service in the same Settlement Period of the preceding Operating Day.

(9) For each of RGS Up, RGS Down, RRS and NSRS, for each hour of the next Operating Day, ERCOT will post the quantity of capacity procured and the MCPC.

(10) ERCOT will be capable of using the MCPC for Non-Spinning Reserve as the MCPC for Regulation Up and/or the MCPC for Responsive Reserve. Similarly, the MCPC for Responsive Reserve could be used for Regulation Up. ERCOT shall not substitute prices until a determination of the conditions to allow substitution of prices from one service to another is approved by the ERCOT Board.

#### 6.15.3.2 ERCOT Ancillary Services Procurement during Adjustment Period (AP)

During the Adjustment Period, ERCOT may procure Replacement Reserves; or as a result of changing conditions, may procure additional Regulation Up, Regulation Down, Responsive and Non-Spinning Services, as appropriate for the conditions, in order to maintain ERCOT System reliability.

ERCOT may procure Ancillary Services to replace those previously awarded to a provider who has subsequently defaulted on his obligation.

**[PIP Issue 123:** ***There is no defined settlement process for this transaction, and no indication of receiving default information from Package 1. The standard mechanism of uplifting costs to load would apply for any procured AS. A transaction and monitoring process will need to be put in place, and then the following paragraph can replace the sentence above.]***

ERCOT may procure Ancillary Services to replace those previously awarded to a provider who has subsequently defaulted on his obligation. The defaulting Entity will be financially responsible for the total cost of the Ancillary Services procured.

If ERCOT requires any Replacement Reserves; or additional Regulation, Responsive Reserve or Non-Spinning Reserve Services during the Adjustment Period, then ERCOT will implement the notification process for these services in accordance with Section 4, Scheduling.

If ERCOT forecasts that there is insufficient capacity available to reliably serve system Load in any settlement period, ERCOT will implement the notification process for Replacement Reserve Services in accordance with Section 4, Scheduling.

Additional Ancillary Services will be allocated to QSEs using the same percentages as the Day Ahead allocation except when the purchase is in the case of a default. In this case the Ancillary Service costs shall be allocated to the defaulting Entity as provided in above.

### *6.15.3.2.1 Specific Procurement Process Requirements for Replacement Reserve Service in the Adjustment Period*

ERCOT shall procure Replacement Reserve Service (RPRS) in the AP as follows:

(1) ERCOT will evaluate Zonal Congestion, Local Congestion, and capacity insufficiency using ERCOT's Operational Model, balanced QSE schedules, Resource Plans and ERCOT forecast of next day Load.

(2) ERCOT will define the level of Resources available to meet next-day reliability needs of the ERCOT System based on QSE schedule submissions, Resource Plans and ERCOT Load forecast. ERCOT will determine incremental Resource capacity available from Generation Resources that are off-line, or Generation Resources that are expected to be off-line in the requested hours or Loads acting as a Resource shown as available in the Resource Plans.

(3) After determining the period of time the RPRS will be needed, ERCOT shall form the RPRS bid from each Resource. ERCOT will divide the capacity price component of the QSEs bid by the number of hours the Resource is needed and add the result to the QSEs hourly price of capacity. This forms the Resource bid price that will be used in all determinations of bid award for RPRS.

(4) RPRS procurement produces a solution that resolves capacity inadequacy, Zonal Congestion and Local Congestion problems simultaneously. The solution of the RPRS is a result of ERCOT performing analysis of the current physical system operations for each hour to recognize potential transmission constraints that would require Resources not currently planned to be available. The purpose and use of the RPRS procurement is to provide capacity from which energy would be available to solve the following system security violations:

(a) ERCOT System capacity insufficiency using any RPRS bid;

(b) Zonal Congestion using the RPRS bids by Congestion Zone in bid price Merit Order and the current physical system operations in the ERCOT System; and

(c) Local Congestion using location specific Resource bids for RPRS and the current physical system operations in the ERCOT System.

(5) ERCOT will solve security violations using a transmission security-constrained mathematical optimization application. The application will solve as if each bid can be proportioned into individual MW bids. The

objective of the optimization is to minimize the cost of the bid-weighted Resource capacity while satisfying all the security constraints.

(6) In the event there is an insufficient amount of RPRS bids submitted to provide a Market Solution to the system security violations, ERCOT will use OOMC to acquire the needed capacity.

(7) The costs associated with resolving system security violations will be identified separately into the following categories: capacity inadequacy, Zonal Congestion and Local Congestion.

(8) The market clearing prices on the capacity insufficiency, CSC constraint and operational constraint will represent the marginal cost for the solution of each constraint and will be produced as an output of the mathematical optimization application. The output of the application will be as follows:

(a) The marginal cost (Shadow Price of the power balance constraint) to solve system insufficiency defines MCPC for insufficiency.

(b) The marginal cost (Shadow Price of the CSC constraint) to solve a CSC constraint defines the congestion price of the CSC constraint.

(c) The marginal cost (Shadow Price of the operational constraint) to solve an operational constraint defines the congestion price of the operational constraint.

(d) The bidder of RPRS is paid the MCPC of the Congestion Zone unless the bid has been selected to solve Local Congestion. RPRS bidders whose bids are taken to solve Local Congestion are paid as bid subject to a Market Solution existing to clear the Local Congestion. The bidder is paid the OOMC price if a Market Solution does not exist.

(9) The cost for resolving CSCs will be allocated to the System Congestion Fund based on the amount of capacity and energy required. The allocation will continue until the limit of the System Congestion Fund ($20M) is exceeded, then uplifted thereafter until a directive is implemented by the ERCOT Board. The System Congestion Fund will be collected from the QSEs representing Load based on a fixed dollar per MWh fee. After implementation of direct assignment of cost for impacting a CSC, QSEs whose schedules have impacts on CSCs according to the Commercial Model (using annually established average Shift Factors for each Zone) at the rate of their impact less their scheduled TCRs shall be charged congestion costs associated with the impact. Any difference between actual and collected costs will be charged to QSEs in proportion to their Load Ratio Share, in accordance with Section 7, Congestion Management.

(10) The costs of resolving the operational congestion underlying the CSC are based on the amount of capacity required to solve Zonal Congestion minus

Commercial Model CSC Congestion cost. This cost will be allocated to all QSEs based on the Load represented by that Entity relative to the total ERCOT Load for the relevant period.

(11) The costs of resolving Local Congestion are based on the amount of capacity required to solve Local Congestion. This cost will be allocated to all QSEs based on the Load represented by that Entity relative to the total ERCOT Load for the relevant period. This cost will be tracked by specific constraint to aid the determination of the potential addition to the constraint as a CSC.

(12) If all of the cost of RPRS is not allocated by one of the above methods then the allocation will be uplifted to all QSEs based on the Load represented by that Entity relative to the total ERCOT Load for the relevant period. If ERCOT collects more RPRS costs in this manner than is necessary, the excess funds collected by ERCOT will be credited to all QSEs based on the Load represented by that Entity relative to the total ERCOT Load for the relevant period.

(13) The RMR Units will be considered as unavailable in RPRS procurement.

(14) In the case of tied bids for the selection of RPRS, ERCOT will select the bid that meets the requirement most closely (achieving the optimal solution). When the price and capacity are identical from unaffiliated bidders, ERCOT may request re-bids.

(15) For RPRS, for each hour, for each Congestion Zone, ERCOT will post the quantity of capacity procured and the MCPCs and Shadow Prices.

(16) On award of RPRS capacity, the energy bid curves provided by the QSE selected to provide RPRS will be added to the Balancing Energy bids stack for the period of time the RPRS is awarded. QSEs may supply multiple price-quantity pair bids for incremental energy to ERCOT for each Resource.

### 6.15.3.3 ERCOT Emergency Ancillary Service Procurement

(1) Any ERCOT procurement of Ancillary Services in the Operating Period other than the deployment of Balancing Energy Service will be pursuant to Section 5, Dispatch.

(2) QSEs may not self-arrange for Ancillary Services procured in response to emergency situations.

#### *6.15.4 Obligations to Honor Ancillary Services Commitments*

The Ancillary Service obligations from the schedule submitted prior to the close of the Adjustment Period are binding commitments of the QSE.

#### *6.15.5 Mandatory Provision of Ancillary Service Capacity to ERCOT*

Notwithstanding any other provision in these Protocols, ERCOT may require a QSE to provide OOMC and OOME Service Resources if necessary to avoid an ERCOT System insufficiency or system emergency condition. If required, ERCOT will procure these Ancillary Services in accordance with the requirements of OOMC and OOME Services.

#### *6.15.6 Provision of Multiple Ancillary Services from a Resource*

An individual Resource may provide more than one Ancillary Service, provided that the sum of the Ancillary Service capacities committed to ERCOT, when added to the bilaterally scheduled level, is within the operating capability of the Resource as specified in the Resource Plan submitted by the QSE.

#### *6.15.7 Insufficiency of Ancillary Services Bids*

If ERCOT receives insufficient Ancillary Service bids to procure required Ancillary Services such that the Ancillary Services Plan is deficient and system security and reliability is threatened, ERCOT shall declare a market insufficiency Alert for the applicable Ancillary Service and will act in accordance with Section 5.6.5, Alert to obtain adequate Resources to ensure reliability. If insufficiency is declared for a particular Ancillary Service in a specific hour, the market for that Service for that hour is closed.

##### 6.15.7.1 Procurement of Ancillary Services During Insufficiency

Upon declaration of market insufficiency, ERCOT will procure and/or arrange for additional capacity of the insufficient Ancillary Service for the affected hourly intervals. ERCOT will not accept any additional bids for the Ancillary service for which market insufficiency has been declared. Compensation for capacity for Ancillary Services procured during market insufficiency and for subsequent procurement after the declaration of market insufficiency will be as per Section 6.8.1.1, Payments for Ancillary Services.

### 6.16 Deployment Policy

Energy from Ancillary Services may be deployed by ERCOT, only in the Operating Period, and only for reliability reasons in order to maintain frequency and system security. Energy will be deployed from Ancillary Services as prescribed by their specific function and may not be used to substitute for other services because of price except as permitted under 6.6.3.1 (10). ERCOT shall deploy all services other than Regulation in a minimum of one (1) Mw blocks.

### *6.16.1 Deployment of Balancing Energy*

#### 6.16.1.1 Creation of the Balancing Energy Bid Stack

(1) The Balancing Energy Service Bid Stack for the Operating Period will be created at the close of the Adjustment Period from the most recent Balancing Energy Service Up and Balancing Energy Service Down bids submitted by QSEs. QSEs can submit revised bids up to the close of the Adjustment Period.

(2) ERCOT may use varying amounts of Balancing Energy for each Settlement Interval as constrained by the QSE-designated bid ramp rate limiting the amount of Balancing Energy Service that can be deployed in each fifteen (15) minute Settlement Interval.

***PIP112: Replace item #1 and item# 2 above with the following once BUL is implemented.***

(1) The Balancing Energy Service Bid Stack for the Operating Period will be created at the close of the Adjustment Period from the most recent Balancing Energy Service Up, Balancing Up - Load and Balancing Energy Service Down bids submitted by QSEs. QSEs can submit revised bids up to the close of the Adjustment Period.

(2) ERCOT may use varying amounts of Balancing Energy for each Settlement Interval as constrained by:

(a) the QSE-designated bid ramp rate limiting the amount of Balancing Energy Service that can be deployed in each fifteen (15) minute Settlement Interval for Balancing Energy Service Up or Down bids, or

(b) the QSE-designated block bid for Balancing Up – Load.

(3) QSEs may designate the amount of Balancing Energy Service that can be deployed in each of the Settlement Interval by specifying a bid ramp rate effective for the whole hour. The limit for the hour is no less than the total amount bid by the QSE. Ten minutes prior to crossing the hour boundary, ERCOT will evaluate the Balancing Energy previously awarded and re-deploy services based on specified bids for the new hour.

(4) QSEs may supply multiple price-quantity pair bids for Balancing Energy Service Up and Balancing Energy Service Down energy (i.e., “up and/or down curves”) to ERCOT for each Congestion Zone.

***PIP112: Replace items #3 and #4 with the following once BUL is implemented.***

(3) QSEs may designate the amount of Balancing Energy Service that can be deployed in each of the Settlement Interval by:

(a) Specifying a bid ramp rate effective for the whole hour. The limit for the hour is no less than the total amount bid by the QSE, and/or

(b) Designating the amount of Balancing Up – Load that can be deployed by specifying blocks.

Ten minutes prior to crossing the hour boundary, ERCOT will evaluate the Balancing Energy previously awarded and re-deploy services based on specified bids for the new hour.

(4) QSEs may:

(a) Supply multiple price-quantity pair bids for Balancing Energy Service Up and Balancing Energy Service Down energy (i.e., "up and/or down curves") to ERCOT for each Congestion Zone, and/or

(b) Supply multiple block bids for Balancing Up – Load Service to ERCOT for each Congestion Zone.

(5) The MCPE for each Settlement Interval for each Congestion Zone will be posted by ERCOT to the marketplace when energy is deployed or recalled. For Settlement Interval during which no Balancing Energy is deployed or recalled, the MCPE is the first (highest) Balancing Energy Service Down bid price for the interval.

(6) ERCOT will develop a forecast of Balancing Energy Service needed in each Settlement Interval.

***PIP138: Replace the above language in Section 6.7.1.1 (6) with the boxed language at the time of system change implementation to post information:***

(6) ERCOT will develop and post a forecast of Balancing Energy Service needed in each Settlement Interval.

(7) ERCOT's System Operator will not have access to individual bid prices or the expected MCPE if the next energy bid is selected. Rather, the Operator will deploy all or a portion of a bid, moving up and down the deployment energy stack. All bids will remain in one stack and the MCPE will be posted, unless there is Congestion. If energy stacks must be separated by Congestion Zone, because of Congestion, the MCPE of each zone will be posted.

(8) ERCOT will provide notice via the Messaging System to QSEs of their awards for Balancing Energy Service as they are selected. QSEs will be required to respond with manual or electronic acknowledgement.

(9) ERCOT shall notify each QSE of its instructed amount of Balancing Energy Service ten (10) minutes prior to the Settlement Interval in which it is to be deployed. QSEs shall be expected to provide a power level during the Settlement Interval that will provide the instructed amount of Balancing Energy Service for that interval.

***PIP112: Replace items #8 and #9 with the following once BUL is implemented.***

(8) ERCOT will provide notice to QSEs via the Messaging System of their awards for Balancing Energy Service, identifying awards that are for Balancing Up – Load. QSEs will be required to respond with manual or electronic acknowledgement.

(9) ERCOT shall notify each QSE of its instructed amount of Balancing Energy Service ten (10) minutes prior to the Settlement Interval in which it is to be deployed. For Balancing Energy bid on Resources other than Balancing Up - Loads, QSEs shall be expected to provide a power level during the Settlement Interval that will provide the instructed amount of Balancing Energy Service for that interval. For ERCOT Instructions to deploy Balancing Up - Loads, the QSE shall be expected to provide the instructed amount of Service by interrupting load. For ERCOT Instructions to deploy Balancing Up – Loads from a QSE's Dynamically Scheduled Load, QSEs shall be expected to ensure that the generation following the load is increased above the actual Dynamically Scheduled Load meter readings by the amount of the signal sent to ERCOT that is estimated in real-time representing the real power interrupted in response to the deployment of Balancing Up Load (BUL). Deployment of energy as a result of adjustments in Dynamic Schedules to account for deployment of BUL will not be considered an Uninstructed Deviation.

(10) Any energy provided by a QSE in a Settlement Interval in which it has not been instructed to provide Balancing Energy Service by ERCOT will not set the MCPE, regardless of whether the energy provided was necessary for the QSE to meet ERCOT's instruction for a future or past Settlement Interval.

**[*PIP 210: When block deployment for Loads Acting as a Resource can be implemented, add the following paragraph*:]**

(11) A Load Acting as a Resource has the option to request a load bid less than or equal to 50 MW to be deployed only as a complete block. To the extent that ERCOT deploys a bid by a Load Acting as a Resource that has chosen a block deployment option, ERCOT shall either deploy the entire bid or, if only partial deployment is possible, skip the bid by the Load Acting as a Resource and proceed to deploy the next available bid.

#### 6.16.1.2 Deployment of Balancing Energy when Congestion Occurs

(1) If the Operational Model indicates there is Zonal Congestion, ERCOT will separate the Balancing Energy Service bids into a Bid Stack for each Congestion Zone.

(2) ERCOT will use the Operational Model to determine the amount and location of Balancing Energy deployment for clearing Zonal Congestion as well as balancing the system.

(3) Except as stated in item (4) below, ERCOT will deploy Balancing Energy bids within a zone in bid price Merit Order.

(4) ERCOT may form specific Resource prices for both incrementing and decrementing a specific Resource to resolve Local Congestion.

(5) As part of the submittal of the Resource Plan, QSEs may specify bid premiums by Resource that would be used to determine Resource-specific prices. Resource-specific incremental prices will be formed by ERCOT by adding the incremental bid premium to the MCPE of the Congestion Zone. The Resource-specific premium price will not be less than the bid premium. Resource-specific decremental prices will be the decremental premium specified.

(6) The actual Shift Factors with respect to the Local Congestion of Resources' individual incremental and decremental prices from above are used to determine the most economical deployment of individual Resources to solve Local Congestion.

(7) ERCOT will instruct QSEs to deploy Balancing Energy Service from a specific Resource through the issuance of a Dispatch Instruction to each Resource according to the most economical solution to resolve the Local Congestion. The deployment of Resource specific Balancing Energy Service must be in equal incremental and decremental amounts. The decremental amount will be selected such that it does not adversely affect any other constraint.

(8) The Dispatch Instruction will specify the current output level, the amount of Balancing Energy Service, and the range of acceptable operation of the specific Resource.

(9) If a Market Solution exists for an incremental Resource-specific instruction, the QSE will be paid the incremental premium specified, times the difference in megawatts between the Resource's current output level and the minimum of the allowed range specified in the Dispatch Instruction at the time of receipt of the Dispatch Instruction for all hours or portions of an hour the Resource is individually dispatched.

(10) If a Market Solution exists for a decremental unit specific Dispatch Instruction, the QSE will be paid the product of: 1) the difference in MCPE minus the decremental premium specified, times 2) the Instruction for all hours or portions of an hour the Resource is individually dispatched.

(11) QSEs shall first meet the specific Resource deployment performance requirements of Section 6.10.7, Individual Resource Dispatch Performance and then provide the Balancing Energy Service deployment instructed pursuant to Section 6.7.1, Deployment of Balancing Energy Service. In the event that a QSE is unable to provide the Balancing Energy Service due to a specific Resource deployment then the QSE will follow the notification procedures established in Section 5, Dispatch.

(12) If a Market Solution does not exist, then ERCOT will use OOME to price the Resources dispatch to resolve the constraint.

(13) The QSEs providing Balancing Energy service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Measures.

#### 6.16.1.3 Deployment of Balancing Energy During Unusual Events

(1) During Unusual Events such as major frequency disturbances greater than 0.05 Hz and unexpected significant Load changes greater than half the amount of Regulation Service purchased in either direction, ERCOT may deploy Balancing Energy so as to mitigate the consequences of the Unusual Event. During such an Event, ERCOT may take one (and only one) the following actions:

(a) Recall Balancing Energy Up Instruction(s) or a Balancing Energy Down Instruction(s) before the fifteen (15) minute Settlement Interval is complete or without the ten(10) minute notice. There is no change to the MCPE in the Settlement Interval for this action. If ERCOT exhausts all recall options, it may deploy unit-specific Balancing Energy based on unit-specific premiums. The cost of these premiums will be charged to the Balancing Energy Neutrality Adjustment set forth in Section 9.6.1, Balancing Energy Neutrality Adjustment, of these Protocols.

(b) Deploy Balancing Energy in the same direction as the immediately previous Instruction without the ten (10) minute notice for the remaining of the current Settlement Interval. For this action, ERCOT must modify the MCPE for the Settlement Interval to the highest price deployed for additional Balancing Energy Up or the lowest price deployed for additional Balancing Energy Down.

### *6.16.2 Deployment of Regulation Service*

(1) RGS will be deployed in response to a change in ERCOT System frequency to maintain that frequency within predetermined limits. Deployment will be accomplished through use of an automatic signal from ERCOT to each QSE provider of RGS.

(2) Dispatch Instructions for regulation capacity will be deployed on a proportional basis, given the ratio of capacity provided, among providers of that capacity having been scheduled for the service.

(3) ERCOT is required to minimize the use of RGS energy as much as practicable by operating its automatic generation control system in conjunction with deploying Balancing Energy with the objective that Regulation Service Up energy and Regulation Service Down energy are deployed in each Settlement Interval.

(4) Energy deployed under RGS will not be accounted for separately, but will be settled at the MCPE for Balancing Energy.

(5) ERCOT shall integrate the control signal sent to providers of Regulation Service Up thus calculating the amount of energy deployed in each Settlement Interval.

(6) ERCOT shall integrate the control signal sent to providers of Regulation Down Service and calculate the amount of energy deployed in each Settlement Interval.

(7) ERCOT shall post to all Market Participants the total amount of deployed Regulation Service Up and Regulation Service Down energy in each Settlement Interval of the previous hour.

(8) QSEs providing Regulation Service shall provide a feedback signal to ERCOT via the MDAS that identifies the amount of regulation energy being provided each control cycle.

(9) For each QSE providing RGS the implied ramp rate in megawatts per minute is the total amount of Regulation Service awarded divided by ten (10).

(10) The QSEs providing RGS shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Performance Measures.

### *6.16.3 Deployment of Responsive Reserve Service*

(1) Responsive Reserve energy shall be deployed as necessary to meet NERC requirements. This shall be accomplished by:

(a) Automatic generation action as a result of a significant frequency deviation, and/or

(b) Through use of an automatic signal and a Dispatch Instruction to deploy Responsive Reserve energy from Generation Resources;

(c) By Dispatch Instructions for deployment of Responsive Reserve energy from Load acting as a Resource via an electronic Messaging System to providers.

(2) Deployment of energy as a result of automatic governor action will not be considered as an Uninstructed Deviation.

(3) ERCOT will deploy Responsive Reserve Service in response to disturbance control assistance requirements as specified in the Operating Guides or after all the bids in the Balancing Energy Services Up Bid Stack have been depleted. Energy from Responsive Reserve Resources will be deployed by ERCOT in accordance with Section 5.6, Emergency and Short Supply Operations.

(4) ERCOT deployment of Responsive Reserve Service Resources will be proportioned first between suppliers who provide RRS using Generation Resources until 33% of the total amount purchased by ERCOT is deployed. On depletion of the first 33%, ERCOT shall declare the EECP in effect and follow emergency provisions in Section 5, Dispatch.

(5) ERCOT will deploy Balancing Energy Service and Non-Spinning Service as soon a practicable to minimize the use of Responsive Reserve energy.

(6) All providers of Responsive Reserve Resources will be required to provide feedback to ERCOT of their availability and level of deployment in Real Time. Except in those instances where a significant frequency deviation has occurred and temporary deployment is necessary to meet NERC requirements, ERCOT shall deploy Responsive Reserve Services according to Section 5.6, Emergency and Short Supply Operations.

(7) Once Responsive Reserve Service is deployed, the obligation to deliver energy shall remain until specifically instructed by ERCOT to stop providing energy from RRS, but not longer than the period of the service is scheduled.

(8) The QSEs providing Responsive Reserve Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Performance Measures.

### *6.16.4 Deployment of Non-Spinning Reserve Service*

(1) ERCOT shall deploy Non-Spinning Reserve Service when it predicts more than 95% of the Balancing Energy Service Up available for the Operating Hour will be deployed.

(2) ERCOT may, in its sole judgment, deploy Non-Spinning Reserve Service as necessary.

(3) Deployment of Non-Spinning Reserve Service Resources will be proportioned among suppliers.

(4) NSRS deployment or recall instructions by ERCOT are not constrained by any ramp rate. However, the QSE is expected to deploy or recall those instructions at a ramp rate that would comply to the instruction in thirty (30) minutes. During a period of NSRS deployment, all energy provided by the QSE responding to the NSRS deployment will be considered instructed.

(5) Energy from Non-Spinning Reserve capacity may be deployed in a Congestion Zone by ERCOT if, in its judgment, not enough Balancing Energy Service Up is available to satisfy reliability needs.

(6) ERCOT will provide notice via the Messaging System to QSEs of their obligations for NSRS energy as the QSE's Resources are selected. Providers will be required to respond with manual or electronic acknowledgement.

(7) All providers of Non-Spinning Reserve Resources will provide notification to ERCOT of their availability and level of deployment.

(8) Once deployed, the obligation to deliver energy will remain until ordered to stop providing by ERCOT (after not less than one hour), but not longer than the period of the service is scheduled.

(9) NSRS may be deployed at any time in a Settlement Interval.

(10) The QSEs providing Non-Spinning Reserve Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Performance Measures.

**[*PIP 210: When block deployment for Loads Acting as a Resource can be implemented, add the following paragraph*:]**

(11) A Load Acting as a Resource has the option to request a load bid less than or equal to 50 MW to be deployed only as a complete block. To the extent that ERCOT deploys a bid by a Load Acting as a Resource that has chosen a block deployment option, ERCOT shall either deploy the entire bid or, if only partial deployment is possible, skip the bid by the Load Acting as a Resource and proceed to deploy the next available bid.

### *6.16.5 Deployment of Replacement Reserve Service*

(1) All units selected to supply this service based on capacity bids will have their Balancing Energy Service bid associated with the service placed in the Balancing Energy Service Bid Stack and will be deployed in accordance with these Protocols.

(2) Replacement Reserve Service providers are required to provide incremental Balancing Energy Service bids for the full megawatt quantity of capacity accepted by, and purchased by, ERCOT in the Replacement Reserve market. Energy bids from Replacement capacity reserves will be treated as any other incremental energy bid.

(3) The QSEs providing Replacement Reserve Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Performance Measures.

### *6.16.6 Deployment of Voltage Support Service*

(1) ERCOT will instruct Generation Resources to make adjustments for voltage support within the capacity limits provided by the QSE to ERCOT. Generation Resources providing VSS will not be requested to reduce megawatt output so as to provide additional megavolt-amperes reactive, nor will they be requested to operate on a voltage schedule outside the limits specified by the QSE without a Dispatch Instruction requesting unit specific dispatch or an OOME instruction.

(2) ERCOT and TDSPs shall develop operating procedures specifying Voltage Profiles of transmission controlled reactive Resources to minimize the dependence on generation-supplied reactive Resources. Generation Resource step-up transformer tap settings will be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(3) The QSEs providing Voltage Support Service shall meet the deployment performance requirements specified in Section 6.10.4, Ancillary Services Deployment Performance Measures.

### *6.16.7 Deployment of Out-of-Merit Energy Service*

Deployment of units for OOME Service will follow Balancing Energy Service deployment guidelines as specified in Section 5, Dispatch of these Protocols.

### *6.16.8 Deployment of RMR Service*

(1) If Market Solutions are not available, and in emergency conditions, ERCOT shall have the option to dispatch a contracted RMR Facility at any time for voltage support or localized transmission limitations, but it must dispatch the unit as early as possible (if conditions merit) once conditions are identified that require the use

of the RMR Facility and only to the extent of megawatt loading necessary to correct the voltage support or localized transmission limitation.

(2) ERCOT may elect to use units under an RMR Agreement before issuing an OOMC or OOME Dispatch Instruction subject to the terms of the Agreement.

(3) ERCOT will deploy RMR in accordance with the RMR Agreement. RMR Agreements with ERCOT are expected to include limitations on the total service hours, megawatt-hour output, and the number of starts available to ERCOT for each RMR Unit.

(4) ERCOT shall issue Dispatch Instructions via the Messaging System for any RMR deployment. Any revisions to those instructions must be communicated via revised Dispatch Instructions.

(5) ERCOT shall publicly post an annual forecast of the dispatch pattern it expects for each contracted RMR Facility as well as monthly and week-ahead forecasts regarding its use of such Facilities.

(6) If adjustments made by ERCOT would result in the QSE exceeding its scheduled amount of generation, then the affected QSE must accommodate these changes by adjusting other Resources such that the Schedule Control Error is minimized.

## 6.10 Ancillary Service Qualification, Testing and Performance Standards

### *6.10.1 Introduction*

QSEs providing Ancillary Services shall meet qualification criteria and performance measures to operate satisfactorily with ERCOT. ERCOT shall develop an Ancillary Services qualification and testing program and Real Time Monitoring Program for all suppliers of Ancillary Services that is based on the key factors needed for reliability. These programs will be approved by ERCOT Technical Advisory Committee and will be included in the Operating Guides. These performance factors shall be measured as precisely and efficiently as possible. General capacity testing verifies a Generation Resources or Load Acting as Resources, net dependable capability. Qualification tests allow the potential provider's portfolio to demonstrate the minimum capabilities necessary to deploy an Ancillary Service, and performance measures assess the Real Time delivery of a service by an Ancillary Services provider.

### *6.10.2 General Capacity Testing Requirements*

QSEs shall provide ERCOT a list identifying each Generation Resource unit that is expected to operate more than 168 hours in a Season as a provider of energy and/or Ancillary Services. ERCOT shall evaluate during each Season of expected operation, the Net Dependable Capability of each unit expected to operate more than 168 hours except for any Generation Resources used solely for energy services and whose capacity is less than 10 MW. Prior to the beginning of each Season, QSEs shall identify the Generation Resources to be tested during the Season and the specific week of the test if known. This schedule may be modified by the QSE (including retests) during the Season. QSEs not identifying a specific week for a Generation Resource unit test must test the unit within the first 168 hours of run time during the Season or operate with a net dependable capability equal to the highest integrated hourly MWh output demonstrated during the first 168 hours of run time. QSEs do not have to bring units on-line or shut down solely for the purpose of the seasonal verification. Any unit for which the QSE desires qualification to provide Ancillary Services shall have its net dependable capability verified prior to providing services using the Generation Resource unit even if it fits the less than 168 hr or small size exception. The capability of hydro units operating in the synchronous condenser fast response mode to provide hydro Responsive Reserve shall be evaluated by Season.

Load acting as a Resource to provide Ancillary Services shall be evaluated by ERCOT each Season, except when the Load interruptability has been verified through response in an actual event. If the Load is under the direct control of a NERC certified operator via a SCADA system, Seasonal evaluation shall consist of a test of the relay function with no actual interruption of Load.

Specific Loads to be used for the first time as a Resource must be correctly evaluated (tripped or simulated trip, if approved by ERCOT) prior to their qualification to provide Ancillary Services. At a time selected mutually by the Load and ERCOT, ERCOT will notify the QSE representing such Load of the need to confirm that Loads proposed to be used as an Ancillary Service can be de-energized, or simulation if applicable, to ERCOT's reasonable satisfaction. ERCOT shall develop a standard test for simulation for Load interruption required under this subsection.

Loads used to provide Responsive Reserve Service shall be qualified for correct operation by its host TDSP.

***PIP112: Replace two paragraphs above with the following when BUL is implemented:***

Load acting as a Resource to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve Services shall be evaluated by ERCOT each Season, except when the Load interruptability has been verified through response in an actual event. If the Load acting as a Resource to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve is under the direct control of a NERC certified operator via a SCADA system, Seasonal evaluation shall consist of a test of the relay function with no actual interruption of Load.

Specific Loads to be used for the first time as a Resource to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve must be correctly evaluated (tripped or simulated trip, if approved by ERCOT) prior to their qualification to provide Ancillary Services. At a time selected mutually by the Load and ERCOT, ERCOT will notify the QSE representing such Load of the need to confirm that Loads proposed to be used to provide Responsive Reserve, Non-Spinning Reserve or Replacement Reserve Services can be de-energized, or simulation if applicable, to ERCOT's reasonable satisfaction. ERCOT shall develop a standard test for simulation for Load interruption required under this subsection. Loads used to provide Responsive Reserve Service shall be qualified for correct operation by its host TDSP.

Load desiring qualification to provide Balancing Up – Load Service shall be verified individually by ERCOT each year, except when the load interruptability has been verified through response in an actual event. If the Load is under the direct control of an operator via a SCADA system, verification may consist of a test of the relay function with no actual interruption of Load.

QSEs shall nominate, at least annually, an amount of Balancing Up – Load (BUL) for which it wishes to be qualified to provide. Specific loads to be used for the first time to provide BUL must be correctly verified prior to their qualification to provide service. At a time selected by ERCOT, the ERCOT operator will notify the QSE of the need to verify that loads proposed to be used as BUL can be reduced. The QSE Operator will immediately initiate the reduction and provide ERCOT with the appropriate signal representing the amount of load for which the QSE desires to be qualified as BUL resources. Load used to provide BUL resources shall be qualified for correct operation by comparing the average energy in a settlement interval as recorded on IDR meters to the expected reduction in total Load indicated by the QSEs signal to ERCOT. Loads may be qualified individually or as a group. Loads previously qualified that have failed performance criteria and require re-qualification shall be performed individually. Once verified, the QSE will be qualified to provide BUL resources in the amount nominated. ERCOT shall maintain a record of the ESI Ids of all qualified Loads used by a QSE as BUL. For NOIEs representing specific Loads qualified as

BULS that are located behind the NOIE Settlement Metering points, the NOIE shall provide an alternative unique descriptor of the qualified BUL Load for ERCOT's records.

Generation Resources and Loads acting as Resources shall be evaluated annually by ERCOT for correct operation of telemetry of the breakers controlling the Resource, of the mapping of QSE-provided telemetry of Ancillary Service energy to the appropriate energy settlement meter, for data rate update requirements and any other required telemetry attributes.

All Generation Resources and Loads acting as a Resource shall meet all requirements specified in the Operating Guides for proper response to system frequency. ERCOT may reduce the amount a Resource may contribute toward Ancillary Services if it finds unsatisfactory performance of the Resource as defined in these Protocols and the Operating Guides.

Qualification of a Resource, including a Load acting as a Resource, shall remain valid for such Resource in the event of a change of QSE for the Resource, provided that new QSE demonstrates to ERCOT's reasonable satisfaction that the new QSE has adequate communications and control capability for the Resource.

### *6.10.3 Ancillary Services Qualification Criteria and Portfolio Test Methods*

Only QSEs that have been qualified and tested may be used to provide Ancillary Services. . ERCOT shall develop and operate its qualification and testing program to meet the following requirements for each Ancillary Service.

A QSE shall be qualified and tested to provide Service prior to initial operation and every five years thereafter. ERCOT is authorized to call up to two unannounced, unscheduled qualification tests after presenting to the QSE supporting information of an indication that a Resource may not be able to meet its stated Net Dependable Capability during any calendar year.

ERCOT may grant a "Provisional Qualification," for a period not to exceed ninety (90) days, to a QSE that has performed an Ancillary Service qualification test (or tests) in good faith but failed to qualify due to problems that, in the sole discretion of ERCOT, are determined to be non-critical for the purpose of providing one or more Ancillary Services. Notwithstanding the failure of a QSE with Provisional Qualification to meet the applicable Ancillary Service criteria, such QSE may provide such Ancillary Service to the extent permitted by the terms of the Provisional Qualification.

#### 6.10.3.1 Regulation

(1) A regulation qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the QSE and ERCOT. QSEs may be qualified to provide Regulation Up or Regulation Down, or both, in separate testing.

(2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice communication circuits in order to validate the voice circuits.

(3) For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Control Area Operator shall send a random sequence of raise, hold, and lower control signals to the QSE, To facilitate accurate measurements, each signal (raise, lower, or hold) shall remain unchanged for at least two minutes. The control signals shall not request QSE portfolio performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the QSE's ability to achieve the entire amount of Regulation Up requested for qualification during the period. One ten (10) minute period will test the QSE's ability to achieve the entire amount of Regulation Down requested for qualification during the period. To facilitate testing of large portfolios, ERCOT may test maximum ramp capability on subsets of Generation Resources in a portfolio.

(4) The QSE's portfolio average real power output for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any real power increase or decrease is the result of the regulation requirement. The correlation coefficient between the expected average power from one minute to the next [limited to no more than the initial value + (request ´ 1/2 ´ stated ramp rate)], and the actual measured real power output during those minutes shall be statistically significant to two positive standard deviations in order to pass the test.

(5) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing RGRS and shall provide a copy of the certificate to the QSE.

### 6.10.3.2 Responsive Reserve

(1) A test for RRS shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(3) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. The QSE shall acknowledge the start of the test.

(4) For the thirty (30) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for (a) the clock minute prior to

the instructions being received from ERCOT; (b) the clock minute following receipt of instructions from ERCOT and continuing for ten (10) minutes; (c) and for each of the subsequent nineteen (19) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of responsive reserve service within five percent (5%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety-percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is within five percent (5%) of expected.

(5) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing RRS and shall provide a copy of the certificate to the QSE.

### 6.10.3.3 Non-Spinning Reserve

(1) A test for Non-Spinning Reserve serve shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(3) At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Non-Spinning Reserve the QSE wishes to be qualified to. The QSE shall acknowledge the start of the test.

(4) For the sixty (60) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for (a) the clock minute prior to the instructions being received from ERCOT; (b) the clock minute following receipt of instructions from ERCOT and continuing for thirty (30) minutes; (c) and for each of the subsequent twenty-nine (29) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve service within five percent (5%) of the amount requested by ERCOT.

(5) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Non-Spinning Reserve and shall provide a copy of the certificate to the QSE.

### 6.10.3.4 Balancing Energy

(1) A test for Balancing Energy Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.

(2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

(3) At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Balancing Energy. The QSE shall acknowledge the start of the test. During the sixty (60) minute duration of the test, within the limits of requested qualification, ERCOT will vary the requested amount of Balancing Energy requested.

(4) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Balancing Energy and shall provide a copy of the certificate to the QSE.

#### 6.10.3.5 Reactive Supply from Generation Resources

(1) The QSE must verify and maintain its stated Reactive Power capacity, as required by the NERC Planning Standards "System Modeling Data Requirements, Generation Equipment." Sections 2.B, Measurement 3 and as may be required by the Operating Guides. Generation Resources reactive capability limits shall be specified considering nominal substation voltage.

(2) The QSE will conduct reactive capacity qualification tests to verify the maximum leading and lagging reactive capacity of all Generation Resources, which it represents. Reactive capacity tests will be performed on initial qualification and periodically at an ERCOT-set interval no more often than once every two years, unless ERCOT has information indicating that current data is inaccurate. The QSE is not obligated to place Generation Resources on line solely for testing.

(3) Maximum lagging power factor reactive operating limit shall be demonstrated during peak Load season, at the net dependable megawatt capability, insofar as system voltage conditions and other factors will allow. The Generation Resource should be required to maintain this level of reactive power for at least fifteen (15) minutes.

(4) Maximum leading power factor reactive operating limit shall be demonstrated during light Load conditions, with the unit operating at its minimum Load, insofar as system voltage conditions and other factors will allow. The unit should be required to maintain this level of reactive power for at least fifteen (15) minutes.

(5) The QSE shall perform the unit automatic voltage regulator (AVR) tests and shall supply AVR data as required by the NERC Planning Standards "System Modeling Data Requirements, Generation Equipment." Sections

2B, Measurement 4, and 2B, Measurement 6 and as may be specified in the Operating Guides. The AVR tests will be performed on initial qualification and periodically at an ERCOT-set interval no more often than once every five years. The AVR tests are run at a time agreed on in advance by the QSE, TDSP, and ERCOT.

### 6.10.3.6 System Black Start Capability

(1) Qualification will be provided to any Black Start Resource that has met the following requirements:

(a) Verified control communication path performance;

(b) Verified primary and alternate voice circuits for receipt of instructions;

(c) Passed the basic starting test;

(d) Passed the line energizing test; and

(e) Passed the Load carrying test.

(2) On successful demonstration of system Black Start Service capability, ERCOT shall qualify the Black Start Resource as being permitted to provide the system Black Start Service capacity and shall provide a copy of the certificate to the Black Start Resource. Qualification shall be valid for one year from the date of the last successful Basic Starting test, three years from the date of the last successful line energizing test, or six years from the date of the last successful Load carrying test, whichever is earliest. Qualification shall be revoked if the Black Start Resource fails to perform successfully during an actual restoration event, until the Black Start Resource is successfully retested. Retesting is only required for the aspect of system Black Start Service capability (basic starting, line energizing, or Load carrying) for which the Black Start Resource failed.

(a) Basic Starting Test

(i) The basic ability of the Black Start Resource to start itself, without support from the ERCOT System, is tested at least once every three years. The test is run during a one-week period agreed on in advance by the Black Start Resource and ERCOT.

(ii) ERCOT shall confirm the dates of the test with the Black Start Resource;

(iii) At a time during a previously agreed test week window not previously disclosed to the Black Start Resource, ERCOT will initiate the test;

(iv) The Black Start Resource, including all auxiliary Loads, will be isolated from the power system;

(v) The Black Start Resource will start without assistance from the system; and

(vi) The Black Start Resource must remain stable (in both frequency and voltage) while supplying only its own auxiliary Loads or Loads in the immediate area for at least 30 minutes.

(b) Line Energizing Test

(i) The ability of the Black Start Resource to energize transmission will be tested when conditions permit as determined by the TDSP but at least once every three years. Tests will be conducted at a time agreed on by the Black Start Resource, TDSP, and ERCOT.

(ii) Sufficient transmission will be de-energized such that when it is energized by the Black Start Resource it demonstrates the Black Start Resource's ability to energize enough transmission to deliver to the Loads the Resource's output that ERCOT's restoration plan calls for the Black Start Resource to supply. ERCOT shall be responsible for transmission connections and operations that are compatible with the capabilities of the Black Start Resource

(iii) Conduct a Basic Starting Test

(iv) ERCOT will direct the Black Start Resource to energize the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if ERCOT agrees, the transmission line can be connected to the Black Start Resource before starting, allowing the Resource to energize the line as it comes up to speed.

(v) The Black Start Resource must remain stable (in both frequency and voltage) while supplying only its own auxiliary Loads or external Loads and controlling voltage for at least thirty (30) minutes.

(c) Load Carrying Test.

(i) The ability of the Black Start Resource to remain stable and to control voltage and frequency while supplying restoration power to the Load that ERCOT's restoration plan calls for the Black Start Resource to supply shall be tested as conditions permit, but at least once every six years.

(ii) Conduct a Basic Starting Test.

(iii) Conduct a line energizing test.

(iv) The TDSP operator will direct picking up sufficient Load to demonstrate the Black Start Resource's capability to supply the required power identified in ERCOT's restoration plan, while maintaining voltage and frequency for at least thirty (30) minutes.

### *6.10.4 Ancillary Service Deployment Performance Measures*

ERCOT shall measure the performance of QSEs providing Ancillary Services according to the following requirements. ERCOT shall identify those QSEs that continually perform at a less-than-satisfactory level and shall pursue compliance mechanisms as specified in the NERC Reliability Compliance Program and as may be further specified in the Operating Guides.

#### 6.10.4.1 Performance Measurement Standard

The expected amount of energy resulting from the deployment instructions of ERCOT is represented as a real power schedule of instructed Ancillary Services from the QSE. This schedule, subject to the agreed-on QSE capabilities, is the requested Ancillary Service output of the QSE Resources. Considering that the QSE may be operating a portfolio and has scheduled a base energy quantity for each Settlement Interval, the total QSE schedule is the amount of power from the base Resource schedule plus the instructed Ancillary Services. The performance of a QSE can be measured by the difference between the actual and expected (requested) Resource output of the QSE. The ERCOT Ancillary Services that result in the deployment of real power applies in the measurement of Real Time provision of the reliability product are (1) Regulation Service, (2) Responsive Reserve Service, (3) Non-Spinning Reserve Service, and (4) Balancing Energy Service. These services combined form ERCOT Reliability Ancillary Services.

Performance measures for the remaining Ancillary Services, Replacement Reserves, Reactive Power Supply from Generation and System Black Start are treated separately.

#### 6.10.4.2 Base Power Schedule Calculation.

For performance measurement purposes, ERCOT shall calculate for each QSE every two (2) seconds the expected power resulting from the QSE's Resource schedule less any other QSEs scheduled as a Resource. The expected power function will be calculated such that when integrated over the settlement period, the power function will equal the energy scheduled in the same interval. The method used will be the same for all QSEs and will be based on a spline routine that develops the coefficients such that the curve passes through the average of the change in energy in each interval. ERCOT will make the spline routine available to all QSEs.

### 6.10.4.3 Balancing Energy Power Schedule

For performance measurement purposes, ERCOT shall calculate for each QSE the Balancing Energy power schedule for the expected power resulting from the change in deployment of Balancing Energy Service. The Balancing Energy power schedule will begin five (5) minutes prior to the target interval and will ramp to the new deployment level at a fixed ramp period.

***PIP110: When the system accommodates the specified bid rate: the following should replace the last sentence above:***

The Balancing Energy power schedule will begin five (5) minutes prior to the target interval and will ramp to the new deployment level at the ramp rate specified in the bid.

### 6.10.4.4 Schedule Control Error

ERCOT will calculate the following for each QSE for each two-second period:

SCE = Actual Generation

+ Load Resource Response to Instructions
– Base Power Schedule
– Sum of any Dynamic Resource Power Schedules
– Expected Governor Response due to frequency of the QSE's portfolio of Resources
– Instructed Ancillary Services power

***PIP112: Add the following paragraph to the equation when BUL language is implemented:***

-- The signal sent to ERCOT that is estimated in real-time representing the real power interrupted in response to the deployment of Balancing Up Load (BUL) for Dynamically Scheduled Load

Instructed Ancillary Services = Instructed (Regulation Service

+ Responsive Reserve

+ Non-Spinning Reserve

+ Balancing Energy power schedule)

***PIP112: Add the following when BUL is implemented:***

ERCOT will determine Load Resource Response to Instructions for Loads that are providing Responsive Reserve, Non-Spinning Reserve or Replacement Resources from the information submitted in the Resource Plan and the telemetry of the real power consumption of the Load Resource. Load Resource Response to Instructions is calculated for each Load Resource that is indicated available in the Resource Plan according to the following formula:

Load Resource Response to Instructions =

MAX [0, MIN((upper operating limit -real power consumption), (upper operating limit - lower operating limit))]

Balancing Energy Up - Load deployments are not considered in the Instructed Balancing Energy power schedule.

### *6.10.5 QSE Real Power Performance Criteria*

#### 6.10.5.1 Base Power Schedule Monitoring Criteria

QSEs that are not providing any Ancillary Services in any of the current Operating Day's markets shall make a good faith effort to cause their Resources to operate to the final Resource bilateral schedules as converted to a base power function according to the method specified in Section 6.10.4.2, Base Power Schedule Calculation.

#### 6.10.5.2 Balancing Energy Monitoring Criteria

QSEs providing only Balancing Energy Services shall declare this intent to ERCOT in the Scheduling Process. On deployment of Balancing Energy, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the equivalent power requirement of the Balancing Energy Dispatch Instruction. ERCOT calculation of SCE for each two (2) seconds and integrated over the Settlement Interval will indicate the average performance of the QSE to supply Balancing Energy. Control performance of the QSE providing only Balancing Energy services shall be deemed satisfactory when ninety percent (90%) of the Settlement Intervals result in an average error of less than five percent (5%) of the average awarded bid in each Settlement Interval.

***PIP112: Add the following two paragraphs when BUL is implemented:***

On deployment of BULs, the QSE shall control its Loads to the difference between its Scheduled power and the BUL instructed amount. ERCOT, at a time established at their discretion, shall determine the Base Load of the sum of all Loads qualified by the QSE as BUL Resources by obtaining actual meter data from IDR meters or directly from the TDSP who has agreed to supply the data. The Base Load is determined by the finding the minimum of the average actual metered energy for the four settlement intervals prior to the first Instruction to deploy BUL and the average actual metered energy for the four settlement intervals following one hour after the last Instruction to recall BUL that Operating Day and the quantity (MW) of Balancing Up – Load bid.

ERCOT shall also integrate for each Settlement Interval the signal provided by the QSE representing the amount of BUL power deployed. The expected total reduction of Load shall be determined by subtracting the integrated signal for each interval from the Base Load as determined above. Control performance of the QSE providing BUL shall be deemed satisfactory when during the first hour in which BUL is deployed in an Operating Day, the actual metered Load for any Settlement Interval during the hour is equal to or less than the amount of energy expected. Failure of the QSE to provide satisfactory control performance during the first hour in which BUL is deployed in an Operating Day will cause ERCOT to withhold payments for any capacity provided as BUL for the Operating Day. Failure to provide at least 90% of the expected total Load during the first hour of deployment will also disqualify those specific Loads and will reduce the amount the QSE is qualified to bid accordingly. QSEs may apply for re-qualification of a specific load according to Section 6.10.2. Repeated failures of the same Load to perform in three Operating Days in a Calendar Year will result in a 90 day waiting period after which the QSE may apply for re-qualification of the specific Load according to Section 6.10.2.

### 6.10.5.3 Regulation Services Monitoring Criteria

Regulation Services Monitoring Criteria will be reviewed by the appropriate ERCOT TAC subcommittee and submitted into these Protocols upon approval.

QSEs providing Regulation Services shall declare this intent to ERCOT in the Scheduling Process. On deployment of any RGS service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus any instructed RGS Service power requirement. ERCOT shall calculate 1-minute and 10-minute averages of each QSE's SCE. ERCOT shall also calculate each QSE's participation factor as the ratio of the QSE's awarded RGS Service to the total amount of RGS Service in ERCOT. For performance monitoring purposes, ERCOT shall limit the deployment of RGS Service to QSEs for each control cycle equal to 125% of the total amount of RGS Service in ERCOT divided by the number of control cycles in ten minutes. RGS Service performance should be calculated only for the intervals for which the QSE is awarded or accepts transfer of responsibility for RGS Service. Satisfactory control performance of the QSE providing only RGS Service shall be deemed acceptable when:

(1) The one (1) minute averages of the QSE's SCE meet the following criteria over the calendar month, and:

(2) The ten (10) minute averages of the QSE's SCE meet the following criteria for 90% of the ten (10) minute periods over the calendar month:

$$AVG(month)\left[\left(\frac{SCE_1}{ParticipationFactor}\right)*\left(\frac{\Delta F_1}{(10*Bias_1)*\varepsilon^2{}_1}\right)\right]\leq 1$$

$$\left|SCE_{10}\right| \leq L_{10} * K\sqrt{ParticipationFactor}$$

Where:

$SCE_1$ is the one minute average of SCE.

$SCE_{10}$ is the ten minute average of SCE.

$Bias_1$ is the one minute average of the ERCOT total bias used in the ACE calculation.

$\Delta F_1$ is the one minute average of frequency deviation from schedule.

*ParticipationFactor* is determined by the ratio of the QSE's hourly-awarded RGS Service (or as modified by transferred responsibility) to the total ERCOT RGS Service awarded.

$\varepsilon_1$ is a constant derived from the targeted frequency bound. It is the targeted RMS of one (1) minute average frequency error from a schedule based on frequency performance over a given year as established according to NERC Performance Requirements by ERCOT and the appropriate ERCOT Subcommittee as assigned by TAC.

$L_{10}$ is a limit to recognize the desired performance of frequency for ERCOT as established according to NERC Performance Requirements by the appropriate ERCOT Subcommittee assigned by TAC. As of September 2000, $L_{10}$ is defined as $(1.65 * E_{10} * Bias_{10})$ where $E_{10}$ is 0.0073 Hz and $Bias_{10}$ is the ten-minute average of the ERCOT total bias used in the ACE calculation.

*K* is a constant established by the appropriate ERCOT Subcommittee as assigned by TAC. *K* should initially be set to .81 to provide an ERCOT wide $L_{10}$ equivalent to the ERCOT wide $L_{10}$ currently used by control areas in ERCOT. This constant can be adjusted to ensure correlation between passing the NERC CPS2 criteria and passing the SCE ten-minute control limit.

### 6.10.5.4 Responsive Reserve Services Monitoring Criteria

QSEs providing Responsive Reserve Services must so indicate in the Scheduling process. On deployment of any Responsive Reserve service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the Instructed Responsive Reserve power requirement. ERCOT calculation of SCE 10 minutes after the deployment instruction will determine the level of Responsive Reserve Service provided. Satisfactory control performance of the QSE providing only Responsive Reserve Services shall be deemed satisfactory when:

(1) Not less than 95% nor more than 120% of the RRS requested, subject to the declared capabilities of the QSE, is provided within ten (10) minutes of ERCOT's deployment Dispatch Instruction and maintained until recalled or expiration of the QSEs service obligation, and

(2) The RRS requested shall return to within 90% to 110% of its pre-deployment scheduled output, subject to the declared capabilities of the QSE, within ten (10) minutes following a recall instruction from ERCOT.

For all frequency deviations exceeding 0.375, ERCOT shall measure and record each two (2) second scan rate values of real power output for each QSE Resource providing Responsive Reserve. ERCOT shall measure and record the MW data beginning one (1) minute prior to the start of the frequency excursion event until ten (10) minutes after the start of the frequency excursion event. Satisfactory performance is measured by comparing the actual response to the frequency response capability response required in the Operating Guides.

Where multiple observations of operating response are available, the QSE must deliver the required frequency response capability 75% of the time during any single calendar quarter.

### 6.10.5.5 Non-Spinning Reserve Services Monitoring Criteria

QSEs providing Non-Spinning Reserve Services must so indicate in the Scheduling Process. On deployment of any Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the instructed Non-Spinning Reserve power requirement. ERCOT's calculation of SCE thirty (30) minutes after the Dispatch Instruction will determine the level of Non-Spinning Reserve provided. Control performance of the QSE providing only Non-Spinning Reserve services shall be deemed satisfactory when:

(1) Not less than 95% nor more than 120% of the Non-Spinning Reserve services requested, subject to the declared capabilities of the QSE, is provided within ten (10) minutes of ERCOT's deployment Dispatch Instruction and maintained until recalled or expiration of the QSEs service obligation, and

*(2)* The NRS requested shall return to within 90% to 110% of its pre-deployment scheduled output, subject to the declared capabilities of the QSE, within ten (10) minutes following a recall instruction from ERCOT.

#### 6.10.5.6 Combinations of Reliability Services Monitoring Criteria

QSEs providing a combination of services shall control their Resources to the additive result of any number of Dispatch Instructions deployed simultaneously. On deployment of any Balancing Energy, Regulation, Responsive Reserve, and Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the additive power requirement of each effective Dispatch Instruction. Satisfactory control performance of the QSE providing a combination of services will determined by one of the following:

(1) The criteria for Regulation if Regulation is one of the services deployed,

(2) The criteria for Responsive Reserve if Responsive Reserve is one of the services provided and Regulation is not, or

(3) The criteria for Non-Spinning Reserve Service if Non-Spinning is one of the services and Regulation and Responsive Reserve are not.

### *6.10.6 Ancillary Service Deployment Performance Conditions*

ERCOT shall determine the performance of providers of Ancillary Services under normal operating conditions. ERCOT shall remove from consideration of average performance of a QSE any period during which any of the following events has occurred.

(1) The twenty (20) minute period where the QSE has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.02 Hz;

(2) The entire Settlement Intervals for all QSEs in which ERCOT has deployed Balancing Energy in response to an Unusual Event;

(3) The entire Settlement Intervals in which ERCOT has deployed OOME to the QSE;

(4) The period where ERCOT issues instructions to any QSE to be deployed at ramp rates in excess of bid ramp rates;

(5) Certain other periods of abnormal operations as determined by ERCOT.

***PIP112: Add item #5 below to the list when BUL is implemented:***

(5) If requested by a QSE, the two scheduling hours following an instruction issued by ERCOT to recall previously deployed Responsive Reserve,

Non-Spin or Balancing Energy Up Services provided from Replacement Capacity that is using qualified Load as the QSE's Resource;

(6) Certain other periods of abnormal operations as determined by ERCOT.

### *6.10.7 Individual Resource Dispatch Performance*

QSEs may receive Dispatch Instructions to operate a specific Resource within limitations specified for an individual Resource. The QSE shall conform to the limitations restricting Resource loading for the effective time of the Dispatch Instruction to within two (2) MW of the requested limitation.

### *6.10.8 Replacement Reserve Service Performance Criteria*

QSEs awarded Replacement Reserve Service to bring a Generation Resource unit on-line or make available Load acting as a Resource shall make a good faith effort to cause their Resources to be available for Balancing Energy instructions at the time requested by ERCOT. Any QSE that anticipates for any reason it may not be able to honor its commitment because of unexpected problems shall notify ERCOT immediately. ERCOT will monitor the Real Time telemetry of the subject Resource breakers and megawatt output to determine if it is available as purchased. Performance shall be satisfactory if the QSE makes available Balancing Energy at least in the amount of the capacity of the awarded unit throughout the period requested. QSEs failing to provide Balancing Energy bids in the amount of the awarded capacity shall not be entitled to compensation for that amount of capacity not made available.

### *6.10.9 Reactive Power Supply from Generation Resources Performance Criteria*

ERCOT will maintain a performance log of QSEs acknowledgements of Dispatch Instructions concerning scheduled voltage or scheduled Reactive output requests. QSEs responding in less than two (2) minutes from the time of issuance of such requests shall be deemed satisfactory.

ERCOT shall monitor the Automatic Voltage Regulator, as required in Section 6.5.7, Voltage Support Service, to assure that it is on and operating automatically at least ninety-eight (98%) of the time in which QSE is providing the Reactive Power Supply from Generation Resources Service. Percentage is calculated as: Time (Automatic Voltage Regulator is on while providing Service)/(Total Time Providing Services) × 100%.

### *6.10.10System Black Start Capability Performance Criteria*

The Black Start Unit shall maintain qualified System Black Start Capability, with the declared capacity and capabilities of the Resources, continuously except during those periods allowed for routine maintenance. During a system restoration emergency, the provider shall respond to the instructions of ERCOT, subject to the declared capacity and capabilities of the system Black Start Capability Generation Resources.

The Black Start Resource shall complete all initial and ongoing qualification requirements.

### *6.10.11ERCOT Operations Performance*

ERCOT shall continuously self-assess its operations and report to all Market Participants its performance in controlling the ERCOT Control Area according to requirements and criteria established by the Operating Guides and NERC Policy and Standards for operation of control areas. ERCOT shall report all substandard operations to the ERCOT Technical Advisory Committee and to the NERC Compliance and Enforcement Committees.

ERCOT shall publish for all Market Participants the total amount of Regulation Up energy deployed and the total amount of Regulation Down energy deployed in each Settlement Interval.

ERCOT will provide monthly a report analyzing the accuracy of each day's Load forecast that was issued at 0600 the Day Ahead of the Operating Day. Similar comparisons shall be made for the 1100 forecast and the forecast in effect at midnight of the start of the Operating Day. The reports will statistically analyze the expected error in energy and peak forecasting.

### *6.10.12Non-Compliance Actions of ERCOT*

ERCOT may revoke any or all Ancillary Service qualification of any QSE providing an Ancillary Service(s) for continued under-performance.

Failure to deliver energy resulting from a valid Dispatch Instruction is cause for ERCOT, at ERCOT's option, to withhold payment for any Ancillary Services purchased and not delivered.

ERCOT will make information relative to each QSE's performance as well as ERCOT's performance, available to the marketplace on a monthly basis, subject to provisions of Section 1.3.2, Restrictions on Protected Information.

# F

# ABSTRACTS OF EPRI PUBLICATIONS ON ANCILLARY SERVICES

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## Measurement of Ancillary Service from Power Plants: Operating Reserve - Spinning and Supplemental and Reactive Power Supply from Generation Resources

**Report**: TR-1000572

**Date Published**

Dec 2000

Final Report - Available On-line

**Project Manager** Abi Samra, Nicholas C.

### *Abstract*

In the deregulated electric utility industry, generators will sell many ancillary services to operating authorities or independent system operators. Such trade in ancillary services will require contractual agreements, and these agreements will need to specify the quality and quantity of service to be supplied and the means to measure them. This report describes methodologies for measuring two ancillary services that generators will provide: operating reserves (spinning and supplemental) and reactive power supply.

### *Background*

Spinning and supplemental reserves were originally informally defined as the higher of two values: a certain percentage of the load in the control area or the largest single unit in the control area. The responsible person at the utility control area would then periodically check the status of the operating units to ascertain that the criterion was being met or direct units to change load or operating mode to meet it. Reactive power supply, long supplied by generators, was always carefully considered in planning and stability studies; but the documentation of specific requirements and/or output has probably been even less formal for reactive power supply than it has been for operating reserves. In recent years there has been renewed demand for testing as reflected in the North American Electric Reliability Council (NERC) Planning Standards Compliance Templates. While reactive power capacity has traditionally been based on information supplied by the generator manufacturer, these compliance templates stress the need to know the actual reactive power limits, control settings, and response times of generation equipment. Further, this data must come from actual operation and not from manufacturer test data. These tests are also required at five-year intervals to certify the unit as an Independent System Operator Resource of Reactive Power Supply from Generation Sources. Certification also requires that the supplier demonstrate the ability to follow a schedule in a timely manner and within a specified error tolerance.

### Objective

- To interpret the certification requirements and performance testing in NERC draft Policy 10 into practical procedures that can be performed routinely for a generating unit, using to greatest possible extent existing station instrumentation
- To demonstrate certification and performance measurement in the field for spinning and supplemental operating reserve and reactive power supply
- To evaluate the data and report on the testing in a form that can be used by generators as guide to performing the certification and performance testing at their own installations.

### Approach

The project team worked with a utility interested in learning how to measure ancillary services and use existing instrumentation and data acquisition equipment to the greatest extent possible to determine a practical and economical method of measurement. The team conducted a demonstration in which, as proposed by NERC, the two operating reserve services were tested simultaneously. The team prepared testing procedures for certification, verified that the required telemetry was operational, and helped the participating utiity collect the necessary data during the testing. At the conclusion of the project, the team assessed the results.

### Results

A field test of operating reserve was conducted on a large steam unit equipped with a digital coordinated boiler turbine generator (BTG) control system. The command to activate the reserve was given locally, simulating the action following a verbal command from the area generation control. This was the method in place for the specific unit. The unit responded more slowly than anticipated by the utility, suggesting that tuning of the BTG system would be required to achieve the declared loading rate. The testing demonstrated the adequacy and practicality of the method proposed by NERC. It appears that the unit as tested could be certified to supply operating reserve (spinning and supplemental) but at a lower loading rate and reserve capacity than declared by the utility before the testing. To respond with the capacity and rate declared, the control system or other components would need to be adjusted.

Reactive power capability and model parameter validation testing was not performed.. Telemetry capability was reviewed and was found to be suitable. Tests of the reactive power response to changes in schedule were conducted and indicated that the reactive power response to changes in schedule did meet NERC requirements.

### *EPRI Perspective*

In the future, the operating authority or independent system operator will not own any of the generating units or be able to direct them to supply the required ancillary services. Rather, they will have to contract for and purchase the necessary ancillary services to ensure that reliability and performance meet applicable criteria. To facilitate this process, this report describes methodologies for measuring two ancillary services that generators will provide: operating reserves (spinning and supplemental) and reactive power supply.

## Demonstration of Black Start Ancillary Service Certification Testing

**Report** TP-114656

**Published**

Dec 1999

Technical Progress - Available On-line

46 pages

**Project** IC7200

**Project Manager** Abi Samra, Nicholas C.

**Contract** Encotech, Inc.

### *Subject*

N3501 Assessment & Optimization

N3603 Plant Support Engineering

### *Abstract*

This is a discussion of Black Start Tests conducted in April 1999 which then served as a demonstration project for certification of black start capability. This work is a companion effort of the EPRI Measurement of Ancillary Services from Power Plants project. Several of the summary, introductory and background paragraphs of the final report (Ref.1) for that project are reproduced here as a convenience to the reader.

### Background

The ancillary services considered here have been supplied for many years by utilities. But the supply was probably established in a less formal way than now planned. For example, the black start capability of a unit was established by a utility or control area from experience and programmed into the utility's or area emergency system's restoration plan. In the future, the Operating Authority (OA) or Independent System Operator (ISO) will not own any of the generating units or be able to direct them to supply such Interconnected Operations Services. Rather, they must contract and purchase the necessary ancillary services of the correct performance and in the required amount to make sure that reliability and performance will stay within applicable criteria.

### Objective

The objectives of this project were: first, to interpret the certification requirements and performance testing drafted by NERC into practical procedures that can be performed routinely for a generating unit, using to greatest possible extent existing station instrumentation; second, to demonstrate certification and performance measurements in the field for each of the two services; and third, to evaluate the data and report on the testing in a form that can be used by Independent Power Producers as a guide to performing the certification and performance testing.

### Approach

The intended approach was to work with a utility interested in learning how to measure ancillary services and use existing instrumentation and data acquisition equipment to the greatest extent possible. This approach was intended to achieve a practical and economical method for measurements. Although the concept of black start is general in nature, the implementation requires extensive tailoring to each application. During the limited duration of this project, it was not feasible to take a black start project from initial planning through test procedure preparation and refinement to the actual execution of a black start test. Rather, the procedures and results provided by one utility for black start tests conducted in April 1999 were reviewed.

### Results

Two hydroelectric generators were used to start two other generators, each located at a different site making it necessary to have two separate transmission paths. The report on these tests, prepared by the host utility, was reviewed in a December 1999 meeting of the authors and the utilities' representatives. The tests performed were compared with the performance criteria proposed by NERC for black start tests. It was determined that the tests were conducted in accordance with these performance criteria and that the hydroelectric power stations could be certified to supply the black start ancillary service.

## Measurement of Ancillary Services From Power Plants: Regulation, Load Following and Black Start

**Report** TR-114246

**Published**

Dec 1999, Research Ended Nov 1999

Final Report - Available On-line

90 pages

**Project** IC7200

**Project Manager** Abi Samra, Nicholas C.

### *Subject*

N3506 Turbines & Generators

D3004 Advanced Planning & Operations

U3005 Planning Capabilities

### *Abstract*

In the deregulated electric utility industry, it is anticipated that many ancillary services will be sold by "generators" to Operating Authorities (OAs) or Independent System Operators (ISOs). Such trade in ancillary services will require contractual agreements, and these agreements will need to specify quality and quantity of service to be supplied. This, again, means that it will be necessary to certify or measure the quality of an ancillary service to be supplied, as well as the quantity actually supplied. Towards that end, this report describes methodologies for measurements of ancillary services of Regulation, Load Following, and Black Start.

### *Background*

The ancillary services considered here have been supplied for many years by utilities. But the supply was probably established in a less formal way than now planned. For example, the load following capability of a unit was established by a utility or control area from experience and programmed into the utility's or area generation control's dispatching algorithm. In the future, the Operating Authority (OA) or Independent System Operator (ISO) will not own any of the generating units or direct them to supply the required ancillary services. Rather, they must contract and purchase the necessary ancillary services of the correct performance, and in the required amount, to make sure that reliability and performance will stay within applicable criteria.

### Objective

- To interpret the certification requirements and performance testing drafted by NERC into practical procedures that can be performed routinely for a generating unit, using to greatest possible extent existing station instrumentation.
- To demonstrate certification and performance measurement in the field for each of the two services.
- To evaluate the data and report on the testing in a form that can be used by "generators" as a guide to performing the certification and performance testing at their own installations.

### Approach

The general approach was to work with a utility interested in learning how to measure ancillary services and use existing instrumentation and data acquisition equipment to the greatest extent possible. This was to achieve a practical and economical method for measurements. For both services Regulation and Load Following, the equivalent of certification testing was performed. The test patterns were selected so that they could also be used to demonstrate performance. Black Start being a very complicated procedure, it was not possible to find an appropriate test site in 1999. Therefore, only the methodology is covered in this report. Test results will be covered in a future addendum.

### Results

A field test was conducted on a steam unit equipped with a digital coordinated boiler turbine control system connected to the area generation control. The unit responded satisfactorily to the load patterns, generated by the control center, used to evaluate the unit's performance as a regulating or load following generator. The performance criteria proposed by NERC for these two ancillary services was evaluated and found to be within expected ranges. It is our opinion that the unit could be certified to supply the ancillary services of Regulation and Load Following.

### EPRI Perspective

This report describes methodologies for measurements of Regulation, Load Following, and Black Start, ancillary services. It is anticipated that such, and other services, will be sold by "generators" to Operating Authorities (OAs) or Independent System Operators (ISOs). Such trade in ancillary services will require contractual agreements, and these agreements will need to specify quality and quantity of service to be supplied.

## Defining Interconnected Operations Services Under Open Access

**Report** TR-108097

**Published**

May 1997, Research Ended Mar 1997

Final Report - Available On-line

156 pages

**Project** IC1466

**Project Manager:** Adapa, Rambabu

EPRIDIV

Power Delivery Group

**Contract**

Operations Training Solutions KEMA-ECC, Inc. Power Technologies, Inc. North

American Elec. Reliability Council

### *Subject*

P3002 Transmission Access Evaluation

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### *Abstract*

Interconnected Operations Services (IOS), also referred to as ancillary services, are the unbundled electric services necessary to facilitate electric market operations. These services provide for system reliability, enable transmission system access, and address equity concerns in electric market operations. This report provides definitions, technical requirements, and commercial rights and obligations associated with these services.

### Background

In Order 888, the Federal Energy Regulatory Commission (FERC) required transmission providers to unbundle six ancillary services in support of basic transmission service. The Order identified these services as scheduling, system control and dispatch; reactive supply and voltage control from generation sources; regulation and frequency response; energy imbalance; operating reserve-spinning; and, operating reserve-supplemental. While the FERC requirement provided a reasonable first step, Order 888 lacked a sufficient technical basis for fully identifying the unbundled electric services necessary for reliable and equitable operation of electric markets. The North American Electric Reliability Council (NERC) realized the importance of this issue and included it as one of four strategic initiatives to address open access issues.

### Objective

To identify those electric services necessary for the reliable and equitable operation of electric markets; to provide sound technical definitions of these services; to define technical requirements for the provision of these services; and to define the commercial rights and obligations of operating authorities and users of transmission networks.

### Approach

Industry representatives formed the Interconnected Operations Services Working Group (IOS WG) as an independent forum with broad representation from all industry segments. Group members met and worked for one year under the joint facilitation of NERC and EPRI to develop this report. EPRI provided two technical consultants and a technical writer to assist in the preparation of the report. The Institute also sponsored two open workshops, the first to gather public inputs and the second to allow public comment on the draft report. The process has been an open one, with numerous public comments received and incorporated into the draft report. Group members delivered the report to NERC to support its development of operating standards and to FERC as a reference document in regulatory matters.

### Results

In this report, the authors identify twelve services as essential to supporting transmission reliability, open access, and the enabling of electric markets. These services are regulation; load following; energy imbalance; operating reserve-spinning; operating reserve-supplemental; backup supply; system control; dynamic scheduling; reactive power and voltage control from generation sources; real power transmission losses; network stability services from generation sources; and, black-start capability. The report presents the group's work in developing these twelve services into a comprehensive framework consisting of IOS definitions, technical/operational requirements, and commercial rights and obligations. The framework also introduces several new concepts:

- A model for IOS supply and delivery markets

- A distinction between community IOS, which are shared services aggregated and deployed by control areas versus individual IOS, which may be managed and deployed to the benefit of an individual transmission user
- The separation of an individual customer's provision of backup supply from the provision of overall system reliability and adequacy.

### EPRI Perspective

A comprehensive reference on IOS, this report may be useful in developing tariffs, service agreements, and operating procedures. NERC will be developing operating policies and standards using it as a foundation, while FERC has been monitoring its development and will use it as a technical reference. Since April 1996 when the FERC Order was published, industry observers have seen very little IOS market activity, principally due to an incomplete understanding of the need for operational requirements related to these services. As a major milestone in the unbundling of electric services, this report offers a sound technical basis for the development of effective markets for IOS. Future research critical to the development of robust IOS markets includes IOS metrics and costing methods. EPRI is sponsoring related projects to develop costing methods that will build on earlier transmission costing work (see TR-105121).

## Survey of Unbundled Electric Power Services

**Report:** TR-109461

**Published**

Feb 1998, Research Ended Aug 1997

Final Report - Available On-line

153 pages

**Project:** 004607 Product Mix Analysis

**Project Manager:** Altman, Art

EPRIDIV

Power Delivery Group

**Contract:** Christensen Associates

### Subject

U3001 Bulk Power Markets & Transmission

M3002 Product & Service Design

M3003 Pricing, Costing & Rate Design

F3006 Fossil Assets Management

### *Abstract*

In the separating, or unbundling, of electric power services, electric energy generation is the sub-service that is of the greatest direct concern to both customers and suppliers. Generation, however, is just one component of several for providing service to customers. Examples include operating reserves, frequency control, reactive power, transportation, and system operations. How a small, representative sampling of utilities from across the United States are presently unbundling their electric power services provides the content for this survey.

### *Background*

Restructuring of the U.S. electric power industry allows customers to buy different parts of their electric power service from different suppliers. Beyond generation of electrical energy, delivery of power requires use of the physical infrastructure necessary for its transport. Ensuring the convenient, safe, and reliable delivery of that energy also requires a number of other services that vendors may supply separately from energy service. Unbundling requires resolution of many questions; at this early stage of restructuring, the industry is simultaneously pursuing different answers to these questions.

### *Objective*

To determine how utilities define, measure, cost, and price their unbundled services as of summer 1997.

### *Approach*

To determine the ways in which utilities are unbundling their services, analysts surveyed three broad categories of vendors: (1) two publicly-owned utilities, (2) six investor-owned utilities (IOUs), and (3) one independent system operator (ISO).

### *Results*

Along with a description of survey respondents, the report gives each respondent's service definitions and explains how they measure, cost, and price their services. The report details how respondents have resolved major issues encountered during unbundling and provides detailed descriptions of each vendor's unbundled service offerings. Readers can use the survey results to plan their participation in the emerging markets for these nongeneration services.

### EPRI Perspective

This report provides a snapshot of unbundling approaches just over one year after the Federal Energy Regulatory Commission (FERC) issued its Order No. 888. This landmark Order set the framework for the unbundling activities of all of FERC's jurisdictional transmission-owning utilities and for many nonjurisdictional utilities. According to survey results, many utilities are following FERC's framework in a very traditional way while others are quite innovative in their approaches. These latter utilities are innovative not only in how they follow FERC's framework but also in how they augment it. The approach that these companies use will determine the short-term profit opportunities in the markets for these services.

## Implications of Energy and Ancillary Service Market Structure for Hydroelectric Generation: A Survey of U.S. ISOs

**Report:** 000000000001006277

**Published**

Sep 2001

Final Report - Available On-line

**Project:** 051250 Hydro Valuation: Survey & Methodology

**Project Manager:** Bahleda, Michael

### Abstract

Hydroelectric's superior technical capabilities – flexibility, fast response, efficiency – make it especially well suited to providing reserve services in restructured and deregulated markets. A generating unit providing reserves in a deregulated market must understand not only the energy market, but also the interrelated markets for several different classes of reserve services. This report investigates how five U.S. independent service providers (IPOs) provide reserve services.

### Background

Previous work for EPRI has investigated the potential role of hydro generators in reserve markets, including economic forces – largely driven by opportunity costs – that would affect a competitive market for reserve services and what hydro's role in such a market might be. Three analyses – a hydro case study, a survey of hydro owners, and a more quantitative economic methodology study of hydro and reserve markets – are documented in EPRI report TR-111707. Much of that work was based on economic theory, underpinned by assumptions about the structure and competitiveness of the reserve market. Empirical investigation of how reserve markets behave and interact with the energy market was not possible at that time. This report addresses some of these same issues empirically.

### Objective

To understand the structure and performance of five operating IPOs with an emphasis on their role as providers of reserve services; to analyze in detail the actual outcomes of observable markets for reserve services in California.

### Approach

The project team looked at five ISO markets in the United States to understand their structure and performance, particularly with respect to reserve services. The team addressed a number of questions, including the following:

- Are reserve services and real power consistently priced with respect to one another?
- Are different reserve services such as regulation, spinning, and supplemental reserves consistently priced with respect to one another?
- Which technologies are most often used to provide different types of reserve services? Does or could hydro play a dominant role in any of these product markets?
- Do market rules and pool protocols influence or distort market outcomes?
- Do reserve prices follow observable diurnal and/or seasonal patterns?

### Results

In order to understand what deregulation may hold in store for hydro, this report reviews the five operating ISOs, with a particular focus on how they handle reserves. Comparison reveals that the ISOs structure their markets differently, in some cases defining different products, and often have different bidding rules and market clearing mechanisms. These different electric markets do not work in the same way, and the details of market structure and operation can have a significant impact both on market performance and on the opportunities that are available to generators. As with other new electric markets, the ISOs tend to run into startup problems and are often forced to change their operation, structure, and rules. Startup problems may be due to flaws in the market's initial structure or rules, or simply to a mismatch between the market structure and existing infrastructure and ownership patterns.

Additional new markets that develop in other U.S. regions or internationally are likely to run into such startup problems as well. This is true whether an ISO, a regional transmission organization (RTO), or some other organizational form operates these markets. In addition to looking at the five currently operating U.S. ISOs, this report also does an in-depth analysis of the recent historical performance of the California energy and reserve markets.

California was chosen for these analyses because its market has been operating for some time now, and detailed data on price, quantity, and market performance is available. California is also interesting because it is a market heavily influenced by hydro, due to the large amount of hydro capacity in and around California. Observed relationships between market prices and quantities in the energy and reserves markets provide insight into the factors that affect market performance and generator opportunities.

### *EPRI Perspective*

In order to make the most of industry restructuring, hydro owners and operators must understand electric market structure and rules and must play a role in designing new markets as they develop. Reserve markets offer potentially big opportunities for hydro generators. While hydro plants currently within regulated utilities are frequently used to provide reserves, and thus may actually operate in a similar manner in a deregulated market, deregulation may offer hydro a new ability to capture some of the value that it provides to electric systems.

## Analyzing Multiple-Product Power Markets: Simulation of Energy and Ancillary Services Prices and System Adequacy

**Report:** 000000000001000571

**Published:** Dec 2000

Final Report - Available On-line

**Project:** 041800 Strategic Information

**Project Manager:** Platt, Jeremy

### *Abstract*

The interpretation of price signals is a primary business task of power market participants, made more challenging by the shift from cost-based to bid-based pricing. This report outlines a novel pricing framework that accounts for the behavior and interaction of forward and real-time energy markets and the ancillary services required to maintain system reliability.

### *Background*

Recent EPRI reports (TR-107270, TR-114246, and TP-114656) and ongoing studies have concentrated on the costs of providing ancillary services and on techniques for measuring and demonstrating provision of ancillary services at generating units. The emphasis is now shifting to understanding ancillary services markets, an alternative source of revenues to the provision of energy alone. These markets are highly interrelated, requiring joint consideration of uncertainty, their interactions and opportunity costs, system conditions, and other variables. The formation of Regional Transmission Organizations (RTOs), responsible for system reliability and required to be "providers of last resort" of ancillary services, provides a further impetus for new approaches to market analysis. LCG Consulting, cosponsor of this report, is responsible for the conceptual advances and applications described here. Results were discussed at an EPRI workshop on ancillary services markets and management in September 2000.

### *Objective*

To describe regional ancillary services market characteristics and examples of multiple-product (energy and ancillary services) electric power market simulation.

### *Approach*

The project team simulated multiple product energy markets to address problems in fossil asset valuation such as anticipating price spikes and bidding simultaneously in multiple markets, hydro unit operations and bidding, modeling price volatility, and evaluating generation and transmission adequacy (system reliability). The project team conducted the simulations using LCG Consulting's UPLAN power market-modeling suite that represents in detail existing and announced generation capacity, regional loads, the transmission network, and uncertainties in these and other factors. The model employs rational expectations equilibrium pricing to capture price dynamics. Overall, the report integrates and builds on a series of recent and forthcoming articles on these topics.

### *Results*

The report discusses the main features of the five markets under the control of Independent System Operators: California, the PJM Interconnection, New England, New York, and ERCOT. These areas will provide lessons in market design for the rest of the country, in which all regions are required to make provisions for ancillary services in the development of RTOs.

While ancillary services have proven profitable for some generators and, on average, may represent about 5-15 percent of total energy costs, the long-term challenge of responding appropriately to continencies in real time persists. Additional revenues will continue to be earned through a combination of reliability payments for capacity and occasionally high prices in real-time energy markets by those able to respond to short-term contingencies.

Historical statistical modeling of electricity markets is not well adapted to joint simulation of the various energy and ancillary services markets. Structural simulation is a bid-based alternative to traditional marginal cost analysis that correctly identifies the opportunity costs faced by generators bidding into multiple product markets. The computational challenges of this approach have been overcome.

Applications of structural simulation illustrate how greater revenues are achieved by participating in multiple markets than by selling energy alone. Joint simulations provide guidance not only to daily bidding, but also to asset valuation. The methodology also provides direct, albeit probabilistic, evidence of price spikes and price volatilities--essential features of the market with important impacts on asset valuation. The approach supports ongoing assessments of generation and transmission system reliability and adequacy, a responsibility of the RTOs, through joint analysis of transmission circumstances, generation assets, and new market rules. Examples are presented for the Eastern Interconnection.

### EPRI Perspective

The advent of competitive multiple product power markets requires a new approach to assessing market behavior that is not captured in production cost modeling. The concepts discussed and illustrated in this report are a true advance in market analysis that has many practical applications in the public and private setting. It will be a challenge for all market participants to keep up with the changing rules in different parts of the country. The methods described here offer a promising response for all market participants interested in understanding the implications of these changes. In cooperation with the cosponsor, EPRI offers a range of studies for companies and agencies assessing these evolving markets.

## Preparing the Ground for Pricing Unbundled Electricity Services: The Importance of Markets

**Report:** TR-106933

**Published**

Nov 1996, Research Ended Oct 1996

Final Report - Available On-line

188 pages

**Project:** IC7200

**Project Manager:** Marsland, Susan

EPRIDIV

Power Delivery Group

**Contract:** Christensen Associates

### Subject

M3005 Marketing Program Evaluation

U3002 Retail Market Service Offerings

M3002 Product & Service Design

M3003 Pricing, Costing & Rate Design

### Abstract

Various forces shape the markets for electric power services. An understanding of the dynamics of new market structures will enable utilities to design and price products so as to increase utility profit, support marketing strategies, and deliver greater value to customers. This report will help electric power firms to capitalize on opportunities arising from the unbundling of electric power services. In specific, the report examines key interrelationships between energy, transmission, and energy imbalance prices and explains how markets will set prices for utility services.

### Background

As the major functions performed by the U.S. electric power industry are unbundled, generation, connection, and merchant services are likely to experience intense competition, while transmission, distribution, and coordination services are likely to continue as regulated monopolies. This will contribute to partial (or possibly complete) vertical disintegration of competitive functions from those remaining as monopoly functions. As a result, both wholesale and retail electricity customers will become increasingly able to purchase the services separately which now comprise today's "full service" delivered electricity. As markets inevitably arise for these unbundled services, opportunities for improving profits from their purchase and sale will also arise. Incumbent electricity providers need to draw on their strengths to capitalize on these opportunities.

### Objective

To explain how the organization of electric power markets will affect unbundled product pricing and suggest how electric power firms may profitably set prices for buying and selling these unbundled services.

### Approach

Investigators first applied economic pricing theory to the particular business circumstances of the U.S. electric power industry. They next described emerging unbundled services, discussed how these services fit into an overall market (their organization), and analyzed issues relating to service pricing. Finally, they identified unbundled pricing opportunities for incumbent electric service providers.

### Results

This report describes principles for profitably designing and pricing unbundled and rebundled electricity power services. The report explains why the pricing of transmission and energy imbalance services is key to the efficient workings of a competitive electric power market, and discusses large issues surrounding the organization of the electric power industry. Included is an in-depth discussion of the electric power market structure and pricing of generation, transportation, merchandizing, and packaged services. Appendices provide methods for costing generation services as well as case studies on electric power pricing and market organization methods used in other countries. Because market organization affects the nature of tradable services subject to pricing, the pricing of electricity services depends on how their markets are organized. For example, some forms of market organization under consideration in the United States would be fundamentally incompatible with certain pricing regimes. Therefore, planning for entry into, or continued presence in, these emerging markets should be conditional on how they will be organized.

Given the rules of market organization, the prices of the various unbundled electric power services are strongly interrelated with one another. Especially crucial are the interrelationships between real power energy, transmission, and energy imbalance prices. Also important are the interrelationships between energy, operating reserve, and load-following prices. The report explains these interrelationships in detail, suggesting how they may be considered in terms of strategic pricing challenges and opportunities.

### *EPRI Perspective*

The unbundling of electric power services provides both dangers and opportunities for the electric power industry. Among the dangers, the mispricing of electric power services may lead to incumbent electric power firms inequitably bearing costs from which new competitors are free. Among the opportunities, unbundling may allow electric power firms to profit from a variety of new wholesale and retail services, and it may broaden the geographic scope for power trades to provide profitable new sales opportunities.

## Costing and Pricing Electric Power Reserve Services

**Report:** TR-108916

**Published**

Dec 1997, Research Ended Aug 1997

Final Report - Available On-line

134 pages

**Project:** 005291 Profiting from Ancillary Services

**Project Manager:** Niemeyer, Eberhardt

EPRIDIV

Power Delivery Group

**Contract:** Christensen Associates

### Subject

F3001 Fossil Fuel Assessment & Cost Management

M3002 Product & Service Design

M3003 Pricing, Costing & Rate Design

U3001 Bulk Power Markets & Transmission

### Abstract

In the future, reserves will be the second largest generation service (after energy) in terms of their revenues and profits. This report presents a methodology that generation and merchant firms need to profitably cost and price the reserve services that they offer. The report also explains how this methodology is generally applicable to a wide range of market structures that such firms might face.

In the regulated world of the past, monopoly utilities provided reserve services from their own portfolios of generation resources. Sometimes they supplemented these resources with purchases from other utilities or with load curtailments. In the more competitive world of the imminent future, reserves will be more widely traded than at present. Furthermore, reserves will be provided by the cheapest available sources regardless of the ownership of those sources. Price will determine the willingness of generators and consumers to provide reserve services, and it may also determine the willingness of reserve users to purchase reserve services.

### Objective

- To present a methodology that both generation and merchant firms can utilize to profitably cost and price their reserve services

### Approach

After describing reserve services, the report explains the principles for determining reserve marginal costs and for profitably packaging and pricing retail reserves services. Next, reserves costs were quantified using two hypothetical systems, equal in size and characterized by realistic data parameters. They have identical loads, including a 70 MW Wind Tunnel Load, two 500 MW Distributor loads, and a 3,500 MW "Rest of System" Load. The peak hourly load for both systems is 4,500 MW. The systems differ only by the fact that System A has larger and fewer generating units than System B.

### Results

The reserve results have a number of cost implications including:

- The spinning and supplemental reserves required to serve a special consumer (the Wind Tunnel) are an order of magnitude higher than the reserves required to serve other similarly sized consumers.
- Generators with large outputs generally have disproportionately large reserve needs.
- The shares of reserve costs attributable to loads generally decline as the reserve time-frame increases. Pie charts illustrate spinning reserve availability costs for Systems A and B.

For System A, the top 5 generators account for a significant portion of reserve costs in all time frames. The range is from 47% in the spinning reserve time frame to 86% in the backup reserve time frame. The reserve costs for loads in all time frames is less than that of the generators. In the spinning reserve time frame, loads account for 49% of the reserve costs, while in the backup reserve time frame, loads account for 15% of the reserve costs.

For System B, the top 5 generators still account for a significant portion of reserve costs in all time frames, but the shares, ranging from 25% in the spinning reserve time frame to 67% in the backup reserve time frame, are not as large as for System A. The reserve cost share of loads in the spinning reserve time frame of 63% is significantly higher than that of generators. Generators, however, account for a majority of reserve costs in the supplemental and backup reserve time frames.

### *EPRI Perspective*

Because the results depend strongly on system-specific characteristics, it would be premature to broadly interpret the implications from the stated results. The report does, however, describe means by which this procedure may be applied to a wide variety of situations, including:

- Sale to another utility of spinning reserves for the on-peak hours of the next week
- Sale to another utility of backup reserves for all hours of the forthcoming summer season
- Sale to a municipality of all its energy and reserve requirements for the next five years, at pre-determined contract prices
- Sale to a merchant firm of load following and backup reserve services for the next year o Sale to a native consumer of backup reserve services to guard against loss of generation supply or transmission service for the next three years

## Cost of Providing Ancillary Services from Power Plants

**Report: TR-107270-**V2

**Published**

Apr 1997, Research Ended Nov 1996

Final Report - Available On-line

Vol 2. 90 pages

**Project:** 004161 Auxiliary System Improvements

**Project Manager:** Stein, Jan

EPRIDIV

Generation Group

**Contract:** Encotech, Inc.

### *Subject*

F3006 Fossil Assets Management

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### *Abstract*

In a deregulated power supply market, extra generating capacity is needed to follow the moment-to-moment load variations in order to maintain the scheduled system frequency. This report describes a new methodology for determining the cost of providing regulation and frequency response service as an ancillary service.

### *Background*

Deregulation of the utility industry has created a need for information on the cost of various services that utilities have provided in the past, but have not priced separately. Precise knowledge of the actual cost of a specific service is prerequisite to pricing this service and selling it in a competitive market at a profit. Regulation and frequency response represents a newly defined ancillary service that can be offered and sold by utilities. One obvious market for this service will be independent system operators, who, because they do not produce power, will be required to purchase the service separate from electric energy. Efforts to develop a costing methodology for this service were cosponsored by EPRI and Consolidated Edison Co. of New York, Inc.

### *Objective*

To define regulation and frequency response service and provide a methodology that can be used to determine the variable cost for a steam cycle generating unit to provide this ancillary service at the power station level.

### Approach

Investigators developed a costing methodology based on common steam power plant engineering and economic principles that will be easily recognized by potential utility users. Edison Electric Institute's Generation Committee and EPRI organized two workshops on ancillary services to discuss the nature of such services and to distinguish between load following and regulation/frequency control services. During the workshops, participants reviewed the draft methodology and provided valuable comments. Investigators implemented and evaluated the methodology using an Excel(TM)-based spreadsheet. Finally, they developed case study examples of numerical implementation of the methodology using fictitious data.

### Results

This report describes the background and nature of regulation and frequency response service, offers a detailed definition of terms, and describes the major steps in implementing the new costing methodology. The report also provides a demonstration calculation using fictitious data to apply the methodology to a 350-MW unit.

The costing methodology was designed so that it does not require any specific measurements or data collection. Rather, it is based on information normally available in a power station that has been in service for some time. When using the methodology, however, it is particularly important that utilities define the unit operating mode for regulation and frequency response service and the alternate (less costly) mode if the unit does not provide the service.

Case studies have demonstrated that the spreadsheet implementation of the methodology is very well suited to perform sensitivity analyses. The influence of a specific parameter (such as boiler efficiency degradation) on the cost of regulation and frequency response service can be determined by running new cases with changed values of the parameter of interest. Key parameters include the type of unit, magnitude of regulating margin, and fuel cost.

### EPRI Perspective

The competitive environment in electric generation is developing quickly. Changes will have profound effects on existing generation facilities, not only for the provision of commodity kilowatt-hours, but also for overall system operations, including the provision of ancillary services. While the competitive market for kilowatt-hours is likely to create tremendous challenges for existing units, emerging ancillary services markets may provide unprecedented opportunities. Identifying and taking advantage of such opportunities for existing units, however, is not yet straightforward. Many gaps in approach and information needs still must be filled, chief among them a better understanding of costs.

The methodology described in this report addresses the cost issue by enabling utilities to determine variable cost elements for regulation and frequency response service. Volume 1 of this series presents a primer on the cost of providing power plant ancillary services. Volume 3 addresses reactive supply and voltage control. Volume 4, expected to be available later this year, discusses operating reserve-spinning.

## Cost of Providing Ancillary Services from Power Plants: Reactive Supply and Voltage Control

**Report:** **TR-107270**-V3 or **TR-107270-**V3SI

**Published**

Jun 1997, Research Ended Nov 1996

Final Report - Available On-line

Vol 3. 115 pages

Vol 3S. 98 pages

**Project:** 004161 Auxiliary System Improvements

**Project Manager:** Stein, Jan

EPRIDIV

Generation Group

**Contract:** PowerGen

### *Subject*

F3006 Fossil Assets Management

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### *Abstract*

This report provides a methodology for determining the variable costs of generating and supplying reactive power to a transmission system, via the generator step-up transformer, for system voltage control. The report examines the costs of additional energy losses, maintenance, repair, and plant aging associated with the generation of reactive power. **TR-107270**-V3SI contains System of International units.

### Background

Generating plants have historically been rated to provide reactive power for voltage control although the cost of this service has rarely been analyzed. However, with the unbundling of generation and system assets and the emergence of more transparent electricity markets, contractual provision must be made for reactive power. This raises the question of how much it costs to provide this service.

### Objective

To provide a methodology for calculating the cost of energy losses and the likely costs associated with repair, maintenance, and plant aging associated with the generation of reactive power.

### Approach

The project team used known equipment parameters to calculate the electrical losses associated with reactive power. They employed a flexible approach that incorporates reasonable assumptions to compensate for unavailable data on the variability of different loss components, magnetic saturation in the generator, and the change in winding resistance with temperature. They estimated maintenance and repair costs by identifying the underlying factors such as vibration, temperature, or stress that can cause damage. They calculated the costs associated with reactive power by scaling the historical incidence of costs with an appropriate factor that accounts for the contribution reactive power generation makes to the underlying damage mechanism.

### Results

This report presents a methodology for calculating the cost of energy losses in the generator and transformer associated with reactive power, as well as related maintenance, repair, and plant aging costs, Individual case studies using the methodology are not included; but the methodology shows that the costs, while small in relation to the cost of real power, are still significant. Because loses are proportional to I2R and increases in losses also increases winding temperature and hence resistance, the effect of generating reactive power is to increase losses in a non-linear manner. The cost of each MVAr of reactive power is relatively low when a plant is operating near to unity power factor but steadily increases as reactive power increases.

The same non-linearity occurs with the maintenance, repair, and aging costs since the main underlying damage mechanisms that relate to reactive power are normally associated with a current squared term. The methodology requires the analysis of each individual cost component at both the unity power factor condition and the required load condition: the difference between these values is the cost required to generate reactive power. A spreadsheet is required to calculate costs over a range of load condition.

Volume 1 of this report, already in print, supplies background information about ancillary services and discusses EPRI's future plants for developing additional tools to help owners of power plants compete in a deregulated power supply industry. Volume 2 provides a detailed description of a methodology for calculating the variable costs of providing Regulation and Frequency Response. Volume 3 refers to U.S. units and Volume 3-SI refers to the System of International Units. Volume 4, forthcoming, will give additional detail on the methodology for calculating the variable costs of providing Operating Reserve-Spinning.

### *EPRI Perspective*

EPRI's plan for its ancillary services projects involves testing methodologies developed for calculating the variable and fixed cost of providing ancillary services using data from several different units. Then, based on the results of these case studies, EPRI expects to identify a range of costs for ancillary services produced by all kinds of power plants. Utilities interested in using the methodologies are urged to contact Jan Stein at EPRI at (650) 855-2390 to participate in the on-going research.

## Cost of Providing Ancillary Services from Power Plants: Operating Reserve - Spinning

**Report: TR-107270**-V4

**Published**

Jul 1997, Research Ended Apr 1997

Final Report - Available On-line

73 pages

**Project:** 004161 Auxiliary System Improvements

**Project Manager:** Stein, Jan

EPRIDIV

Generation Group

**Contract:** Encotech Engineering, P.C.

### *Subject*

F3006 Fossil Assets Management

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### Abstract

With the deregulation of the electric utility industry, many utilities need to know more accurately the costs of various service that they have provided in the past but not priced separately. This report provides a methodology to determine the variable cost for a steam cycle generating unit to participate in Operating Reserve - Spinning service.

### Background

Before the deregulation of the electric utility industry, Operating Reserve - Spinning Reserve was normally provided by each utility to cover its own load or organized by an Area Control Center to cover the load inside a defined area. The variable cost of the service was not usually calculated separately but simply considered as part of the cost of producing electricity. In the future, Independent System Operators (ISOs) or their equivalents will be responsible for Operating Reserve - Spinning Reserve inside its operating/control area and will often have to purchase the service from generators of electricity. In order to offer and sell the service with a profit in a competitive market, suppliers will have to understand its variable cost.

### Objective

To define Operating Reserve - Spinning Reserve; to provide a methodology for calculating the variable cost of the service when supplied from a steam cycle unit at the power station level.

### Approach

The project team defined Operating Reserve - Spinning Reserve on the basis of FERC Order 888 and the conclusions of the Interconnected Operations Services (IOS) Working Group. The team developed a methodology to identified the additional cost incurred at the power plant level for providing Operating Reserve - Spinning Reserve for a specific time period. They implemented the methodology on an Excel" based spread sheet.

### Results

Operating Reserve - Spinning Reserve is a newly defined separate service that can be offered and sold by a generator of electric power. In this study, the variable costs for the service are defined at the station or unit level. The costing methodology makes use of the power plant models previous developed to calculate the costs for Regulation and Frequency Response service in Volume 2 of this report. The structure of the methodology makes it straightforward to add additional cost categories.

An expected finding from case studies is that the specific cost of power generated in spinning reserve mode is quite high compared to the optimum cost of power from the same unit due to the poor heat rate of most thermal power units at low load. If the unit could have been operated at high load instead of spinning reserve, there is a lost opportunity cost that may double to cost of the spinning reserve service.

Volume 1 of this report supplies background information about ancillary services and discusses EPRI's future plants for developing additional tools to help owners of power plants compete in a deregulated power supply industry. Volume 2 provides a detailed description of a methodology for calculating the variable costs of providing Regulation and Frequency Response. Volume 3 provides a methodology for calculating the costs associated with the generation of reactive power.

### *EPRI Perspective*

EPRI's plan for its ancillary services projects involves testing methodologies developed for calculating the variable and fixed cost of providing ancillary services using data from several different units. Then, based on the results of these case studies, EPRI expects to identify a range of costs for ancillary services produced by all kinds of power plants. Utilities interested in using the methodologies are urged to contact Jan Stein at EPRI at (650) 855-2390 to participate in the on-going research.

## Fixed Costs of Providing Ancillary Services from Power Plants: Reactive Supply and Voltage Control, Regulation and Frequency Response, Operating Reserve-Spinning

**Report:** TR-107270-V5

**Published**

Dec 1998, Research Ended Oct 1998

Final Report - Available On-line

Vol 5. 58 pages

**Project:** 005330 Interconnected Operator Services

**Project Manager:** Stein, Jan

EPRIDIV

Generation Group

### *Subject*

F3006 Fossil Assets Management

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### Abstract

For steam-cycle generating units that want to profitably sell Reactive Supply and Voltage Control (RS-VC), Regulation and Frequency Response (RFR), and Operating Reserve-Spinning (ORS) services, this report describes methodologies to determine fixed costs. The methodologies are designed for "generators" of electricity planning to offer these ancillary services in a competitive market.

### Background

With deregulation of the electric utility industry, many "generators" need to know more accurately the costs of various services that they have provided in the past but not priced separately. Knowing the exact cost of a specific service is a prerequisite to pricing this service and selling it in a competitive market place. Among the services commonly named "Ancillary Services," the Federal Energy Regulatory Commission (FERC) has, in its Order No. 888, defined a set of six services that it believes must be "unbundled" to provide "open access." Another set of similar services, some with definitions slightly differing from FERC, was created by the Interconnected Operations Services Working Group (IOS-WG) sponsored by NERC. RS-VC, RFR, and ORS appear in both lists.

### Objective

To describe RS-VC, RFR, and ORS and provide methodologies that can determine their fixed costs for a steam-cycle unit at the power station level.

### Approach

Project analysts identified two possible methods for determining the capital cost of the station or unit components needed for a specific service. The first method defined the costs (at net book value) of the components identified by plant engineers to produce RS-VC, RFR, and ORS services. The second method consisted of obtaining the current price of installed equipment capable of providing the service and the price for equipment of the same capacity, but not equipped for or capable of providing the service.

The project team used a period of one year for their costing methodologies, assuming that the specific service would be provided (or be available) during the entire evaluation period. They further assumed that there was no interaction among services. This assumption meant that fixed costs for one service do not depend on whether another service also is supplied during the evaluation period. While the methodologies are based on common steam power plant engineering economic and accounting principles, they required input and guidance from many sources to formulate them into a usable form. For implementation and evaluation of the methodologies, the team used Excel(R) based spreadsheets with real data from participating utilities.

### Results

The report describes in detail the methodologies needed to determine the fixed cost for RS-VC, RFR, and ORS, respectively. These methods are shown in spreadsheet form, including descriptions of spreadsheet pages together with calculations for a fictitious unit for each of the three services. The algorithms are listed in their entirety and can easily be used in most available spreadsheet programs.

### EPRI Perspective

To offer and profitably sell any of these three services in a competitive market, utilities must understand the fixed costs associated with providing the service. This report will help facilities determine the fixed costs for RS-VC, RFR, and ORS services. Variable costs for these same services have been studied under previous EPRI sponsorship. See these EPRI reports: Cost of Providing Ancillary Services from Power Plants (TR-107270-V1: Primer; V2: Regulation and Frequency Response; V3: Reactive Supply and Voltage Control and V4: Operating Reserve-Spinning).

## Cost of Providing Ancillary Services from Power Plants: Volume 1: A Primer Published

**Report:** TR-107270-V1

Mar 1997, Research Ended Dec 1996

Final Report - Available On-line

Vol 1. 253 pages

**Project:** 008019 Exploratory Research in Polymeric Materials

**Project Manager** Stringer, John

EPRIDIV

Generation Group

**Contract** T/Systems

### Subject

F3006 Fossil Assets Management

P3003 Power System Operations & Control

U3001 Bulk Power Markets & Transmission

### Abstract

As the electric power industry undergoes deregulation, managers of power plants will need to decide whether it makes business sense to provide ancillary services such as Reactive Supply and Voltage Control and Operating Reserves-Spinning. This report outlines two methodologies for calculating the variable cost of providing ancillary services from power plants.

### Background

In an increasingly deregulated industry, new markets will emerge for power plants that can supply reactive power, operating reserves, and system stability. These services are called ancillary services by the Federal Energy Regulatory Commission (FERC). Since 1994, EPRI has been working with utilities to develop tools for calculating the cost of providing such services.

### Objective

To consult with power utility personnel on their requirements for methods to calculate the costs of ancillary services.

### Approach

The project team analyzed the recent tariff filings of 20 utilities from around the United States. The team held two workshops with utility personnel to discuss the industry's requirements and needs for methods that calculate the cost of providing generation based ancillary services.

### Results

The report provides background information about ancillary services including the 1996 FERC definition of ancillary services and the current NERC definitions of Interconnected Operations Services (IOSs). The report outlines methodologies for calculating the variable costs of providing Reactive Supply and Voltage Control and Operating Reserves-Spinning, including all the overheads used to illustrate these methodologies at the two workshops. The report also discusses EPRI's future plans for developing additional tools to help owners of power plants compete in a deregulated power supply industry, including methodologies for calculating fixed as well as variable costs.

Workshop participants identified the principle users of the cost methodologies as plant managers, operating supervisors and shift supervisors, control room operators, production management, and staff. These personnel would need at least daily information about the cost of providing ancillary services. Rate designers, power marketers, business planners, and regulators would need to know these costs on a seasonal or yearly basis. The methods should help management assess risk versus reward issues, understand cost causation factors, and evaluate "what if" scenarios as well as provide needed inputs in tariff filings.

Three additional volumes of this report are forthcoming. Volume 2 will provide a detailed description of a methodology for calculating the variable costs of providing Regulation and Frequency Response. Volume 3 will give additional detail on the methodology for calculating the variable costs of providing Reactive Supply and Voltage Control. Volume 4 will give additional detail on the methodology for calculating the variable costs of providing Operating Reserve-Spinning.

## *EPRI Perspective*

EPRI's plan for its ancillary services projects involves testing methodologies developed for calculating the variable and fixed cost of providing ancillary services using data from several different units. Then, based on the results of these case studies, EPRI expects to identify a range of costs for ancillary services produced by all kinds of power plants. Utilities interested in using the methodologies are urged to contact Jan Stein at EPRI at (650) 855-2390 to participate in the on-going research.

# G
# ABSTRACTS OF IEEE AND CIGRE RECENT PUBLICATIONS ON ANCILLARY SERVICES

## Ancillary Services-Reactive And Voltage Control

**Author(s):** Trehan, N.K.

**Author Affiliation:** US Nuclear. Regulatory Comm., Rockville, MD, USA

**Conference Title**: 2001 IEEE Power Engineering Society - Winter Meeting.

**Language:** English Document Type: Conference Paper (PA)

**Treatment:** Practical (P)

**Descriptors:** electricity supply industry; load regulation; power system control; power system security; reactive power control; voltage control.

**Identifiers**: bulk power system security; bulk power system adequacy; ancillary services; electrical transmission providers; power system control; reactive supply; voltage control; spinning reserve; supplemental reserve; energy imbalance; load following; backup supply; power loss; dynamic scheduling; black-start capability; network stability; generation unavailability; transmission capability; electric grid; interconnected electric grid.

**Abstract**: To maintain security and adequacy in a bulk power system, FERC's Order No. 888 in 1996 specified six services called ancillary services that the electrical transmission providers must provide. These six services constitute system control, reactive supply and voltage control, regulation, operating spinning reserve, operating supplemental reserve and the energy imbalance. Besides these six services, there are additional six services for which the transmission providers are not responsible. These six services constitute load following, backup supply, real power loss, dynamic scheduling, black-start capability and network stability. Despite the extensive preparations and planning by the ten electrical grid Security Councils, the combination of generation unavailability and limited transmission capability coupled with unanticipated circumstances such as extreme weather conditions could result in shortages of generation sources for reactive supply (VArs) and voltage control that could affect the security of the electric grid. This paper discusses mainly the reactive and voltage control portion of the ancillary services associated with the interconnected electric grid.

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## A multi-criteria optimization of ancillary services in a competitive energy market

**Author(s):** Schmitt, A.; Verstege, J.F

**Language:** English

**Author Affiliation:** Wuppertal Univ., Germany

**Treatment:** Economic aspects (E); Theoretical (T)

**Conference Title:** 2001 IEEE Power Engineering Society - Winter Meeting

**Descriptors:** electricity supply industry; frequency control; losses; Pareto distribution; power supply quality; power system control; power system economics; power system reliability; power transmission; voltage control

**Identifiers**: multi-criteria optimization; ancillary services; competitive energy market; management system; power system operator; technical objectives; economical objectives; combined optimization; costs minimization; reserve aid; transmission losses; power system operation; reliability; quality; frequency control; voltage control; transmission capacity; Pareto-based evolution strategy; multi-criteria optimization problem; mathematical models

**Abstract:** This paper reports on a management system, which supports the power system operator to provide ancillary services in a competitive energy market under economical as well as technical objectives. In a combined optimization the minimization of the costs for providing reserve aid for covering transmission losses are presented as well as several parameters of power system operation, which represent the reliability and quality of the system like frequency control, voltage control or transmission capacity. Since the objectives compete, a Pareto-based evolution strategy was selected, in order to solve this multi-criteria optimization problem. The mathematical models representing the competitive objectives are presented and exemplary case study results are given. (10 Refs)

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## Ancillary services and reliability

**Author(s):** Kafka, R.J.

**Language:** English

**Author Affiliation:** NONE LISTED

**Treatment:** Practical (P)

**Conference Title:** Proceedings of 2001 - Winter Meeting of the IEEE Power Engineering Society

**Descriptors:** power transmission reliability

**Identifiers**: ancillary services; reliability; Order 888; Federal Energy Regulatory Commission; FERC; energy transmission; reliable operation; Transmission System; Transmission Provider; North American Electric Reliability Council; NERC; operating policy; interconnected operations services; open process; competitive market

**Abstract**: In Order 888, the Federal Energy Regulatory Commission (FERC) identified a set of ancillary services "necessary to support the transmission of energy and capacity from resources to loads while maintaining reliable operation of the Transmission Provider's (TP) Transmission System in accordance with Good Utility Practice." Overlapping the time period in which the FERC defined the ancillary services to be offered in a Transmission Provider's tariff, the North American Electric Reliability Council (NERC) began the development of an operating policy (Policy 10) to define in measurable terms the provision of a somewhat different set of interconnected operations services (IOS). The intent is to develop through an open process a set of provision standards that will allow the competitive supply of IOS (and ancillary services) by generation sources not owned by the Transmission Provider. This presentation addresses the need for ancillary services and the provision of such services through a competitive market. (0 Refs)

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## Trading electricity and ancillary services in the reformed England and Wales electricity market

**Author(s):** Strbac, G.

**Language:** English

**Author Affiliation**: Univ. of Manchester Inst. of Sci. & Technol., UK

**Treatment**: Economic aspects (E); General, Review (G)

**Conference Title**: 2001 IEEE Power Engineering Society - Winter Meeting

**Descriptors**: electricity supply industry; power system economics; risk management

**Identifiers**: reformed England and Wales electricity market; electricity trading; ancillary services; generating companies; bidding strategies; risk-management activities; UK; deregulated utility environment; competing markets

**Abstract**: The paper stresses the need for generating companies to apply sophisticated tools to support and develop bidding strategies and risk-management activities in the new UK deregulated utility environment. The paper also discusses the need for generating companies to understand and quantify the value of various energy and ancillary services products in order to optimally allocate their activities in a number of competing markets. (6 Refs)

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## Real-time coordinated dispatch in unbundled electricity markets with multi-zone

**Author(s):** Wang, X.; Song, Y.H.; Lu, Q

**Language**: English

**Author Affiliation**: Brunel Univ., Uxbridge, UK

**Treatment**: Theoretical (T)

**Conference Title**: UPEC 2000. 35th Universities' Power Engineering

**Descriptors**: control system analysis computing; control system synthesis; electricity supply industry; load dispatching; load flow control; optimal control; power system analysis computing; power system control; real-time systems

**Identifiers**: multi-zone unbundled electricity markets; real-time coordinated dispatch; pool day-ahead auction market; ancillary services market; bilateral contract market; independent system operator; balancing mechanism; power system security; bid prices; network congestion; operating reserves; bilateral contract curtailment; inter-zonal congestion management; intra-zonal congestion management; modified optimal power flow; IEEE 30-bus test system; control simulation; computer simulation

**Abstract**: A new coordinated real-time optimal dispatch method for unbundled electricity markets with multi-zone is proposed in this paper. In this method, pool day-ahead auction market, ancillary services market and bilateral contract market can be dispatched coordinately by the independent system operator (ISO) through a balancing mechanism for the purpose of system security. To eliminate network congestion, operating reserves and bilateral contract curtailment, together with real-time balancing resources, can be called upon by ISO in light of their bid prices. The procurement of replacement of operating reserves which have been used is also embedded into the objective of the real-time optimal dispatch. In cases of markets with multi-zone, two different models are given for inter-zonal and intra-zonal congestion management, respectively. The linearized model of a modified optimal power flow is employed to implement such a method. The IEEE 30-bus test system is studied to illustrate the proposed method. (10 Refs)

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## Generator contribution to a line reactive power flow

**Author(s):** Grgic, D.; Gubina, F.

**Author Affiliation**: Fac. of Electr. Eng., Ljubljana Univ., Slovenia

**Conference Title**: PowerCon 2000 - International Conference on Power System Technology

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: costing; electric power generation; load flow; power system dynamic stability; power transmission economics; reactive power; tariffs

**Identifiers**: line reactive power flow; generator contribution; ancillary services management; reactive power transmission pricing; generation distribution factors; voltage stability assessment; power system decomposition; voltage instability protection

**Abstract**: The management of ancillary services may also require pricing of reactive power transmission. In the paper, a simple approach to generation distribution factors for reactive power is presented. The new method is based on the reactive power flow directions and yields contribution of the generators to the reactive power flow on a line. These contribution factors are referred to as nodal generation distribution factors. For their calculation, the data on reactive power flows are needed and no system matrices manipulation is required. These factors have been successfully applied in voltage stability assessment based on power system decomposition. It is also expected that they can be used for protection against voltage instability since they determine the most appropriate generators for such actions, and also for reactive power transmission service pricing. (6 Refs)

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## Reliability and reserve in competitive electricity market scheduling

**Author(s):** Flynn, M.; Sheridan, W.P.; Dillon, J.D.; O'Malley, M.J.

**Author Affiliation**: ESB Nat. Grid, Dublin, Ireland

**Journal**: IEEE Transactions on Power Systems vol.16, no.1 p.78-87; Publisher: IEEE, Publication Date: Feb. 2001

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; power generation economics; power generation reliability; power generation scheduling; power system analysis computing; recurrent neural nets

**Identifiers**: competitive electricity market scheduling; generating unit reliability; security criteria; augmented Lagrangian dual function; recurrent neural network; ancillary services; augmented Lagrangian; power generation scheduling; reserve

**Abstract**: Power systems are typically scheduled at least cost subject to operational and security constraints. Generally, no account is taken of generator reliability when scheduling units. Also, the security criteria, which include reserve, are usually deterministic in nature. This paper proposes a method to consider generator reliability explicitly in the scheduling problem. A competitive structure is proposed which includes a market for reserve. This is formulated as an augmented Lagrangian dual function and is solved using a new recurrent neural network. The price for reserve is used, along with the unit reliability, to find a balance between the cost of reserve and the risk of not providing it. (21 Refs)

## Spot pricing of electricity and ancillary services in a competitive California market

**Author(s):** Siddiqui, A.S.; Marnay, C.; Khavkin, M.

**Author Affiliation**: Electr. Markets & Policy Group, Lawrence Berkeley Lab., CA, USA

**Conference Title**: Proceedings of the 34th Annual Hawaii International

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: costing; electricity supply industry; power system economics; power system reliability

**Identifiers**: electricity spot pricing; ancillary services; competitive electricity markets; vertically integrated utilities; system reliability; independent system operator; engineering specifications; spot market; market clearing prices

**Abstract**: Typically, in competitive electricity markets, the vertically integrated utilities that were responsible for ensuring system reliability in their own service territories, or groups of territories, cease to exist. The burden falls to an independent system operator (ISO) to ensure that enough ancillary services (AS) are available for safe, stable, and reliable operation of the grid, typically defined, in part, as compliance with officially approved engineering specifications for minimum levels of AS. In order to characterize the behavior of market participants (generators, retailers, and an ISO) in a competitive electricity market with reliability requirements, spot markets for both electricity and AS are modeled. By assuming that each participant seeks to maximize its wealth and that all markets clear, we solve for the optimal quantities of electricity and AS traded in the spot market by all participants, as well as the market clearing prices for each. (9 Refs)

## On the various design options for ancillary services markets

**Author(s):** Papalexopoulos, A.; Singh, H.

**Author Affiliation**: NONE LISTED

**Conference Title:** Proceedings of the 34th Annual Hawaii International Conference on System Sciences

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: costing; electricity supply industry; power system economics

**Identifiers**: ancillary services markets; market design options; price volatility; competitive auctions; independent system operator; electric power deregulation; auctions; price reversal

**Abstract**: This paper discusses various market design options for procuring, pricing and settling ancillary services via competitive auctions by an independent system operator (ISO). The paper also discusses problems and potential solutions associated with these market design options based on actual experience of operating ISOs. These problems include price volatility and spikes and price reversals for the various components of the ancillary services that can create perverse incentives in the marketplace. (10 Refs)

## Electricity and ancillary services markets in New York state: market power in theory and practice

**Author(s):** Schuler, R.E.

**Author Affiliation**: Cornell Univ., Ithaca, NY, USA

**Conference Title**: Proceedings of the 34th Annual Hawaii International Conference on System Sciences

**Language**: English

**Treatment:** Practical (P)

**Descriptors**: costing; electricity supply industry

**Identifiers**: ancillary services markets; market power; multi-attribute commodity; price; domestic electricity market

**Abstract**: Since electricity, and its reliable provision on command, is a multi-attribute commodity, it should be priced over multiple dimensions if it is to be provided efficiently, and that requires multiple but related markets. So far New York is the only domestic electricity market that has introduced separate segments for ancillary services, together with eleven locationally defined markets for energy. By fragmenting the market over dimensions of space, time, and various contributing factors to reliability, the chances for greater efficiency are available in theory, but by spreading the market out, the possibility also exists of having fewer potential suppliers for each segment, thereby increasing opportunities to exercise market power at particular times and places. In fact several instances of market power have been observed that are not surprising with the benefit of perfect hindsight, and the lessons learned are combined with theoretical principles to establish guidelines for future electricity market design and operation. (5 Refs)

## The design of efficient market structures for ancillary services [electricity industry]

**Author(s):** Outhred, H.

**Author Affiliation**: New South Wales Univ., Kensington, NSW, Australia

**Conference Title**: Proceedings of the 34th Annual Hawaii International Conference on System Sciences

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: economic cybernetics; electricity supply industry; power system economics

**Identifiers**: efficient market structure design; ancillary services; restructured electricity industry; commercialization; instantaneous transmission; commercial activities; electrical energy; commodity; economically efficient outcomes; Australia

**Abstract**: The electricity industry has particular characteristics that create barriers to its successful commercialization. Electrical energy is instantaneously transmitted from generators to end-use equipment according to physical laws rather than commercial contracts. Any blueprint for commercialization must be compatible with these characteristics. The main commercial activities in a restructured electricity industry assume that electrical energy behaves as a commodity. Ancillary services play a crucial role in underwriting that assumption. Therefore, it is even more complex to achieve economically efficient outcomes in ancillary services than in the main commercial activities. This paper discusses approaches to this problem, with particular emphasis on recent proposals for changes to the implementation of ancillary services in Australia. It will be several years before the success of these proposals can be measured. (3 Refs)

## Optimal and reliable dispatch of supply and demand bids for competitive electricity markets

**Author(s):** Yu, Z.; Nderitu, D.G.; Sparrow, F.T.; Gotham, D.J.

**Author Affiliation**: Purdue Univ., West Lafayette, IN, USA

**Conference Title**: 2000 Power Engineering Society - Summer Meeting

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; load flow; optimization; power generation dispatch; power generation economics; power system interconnection; tariffs

**Identifiers**: competitive electricity markets; optimal dispatch model; independent system operators; real power dispatch; ancillary services; demand bids; supply offers; societal benefit; zonal market clearing prices; DC power flow equations; integer decision variables; inter-zonal connection

**Abstract**: This paper presents an optimal dispatch model for competitive electricity markets where independent system operators (ISOs) dispatch real power and ancillary services based on supply offers and demand bids. The model maximizes the "net" societal benefit while respecting various constraints. Zonal market clearing prices are determined and DC power flow equations are used to capture the physics of real power flows. In addition, integer decision variables are used to capture unit's on/off status and automatic generator control (AGC)/load following capability in a reliable way. Each producer is assigned a power flow on each inter-zonal connection and this will be used for accounting purposes. A six zone, 18-unit system is used as a case study with satisfactory results. (8 Refs)

## Multi-objective solutions for coordinating auctions of different commodities in power markets

**Author(s):** Garng Huang; Qing Zhao

**Author Affiliation**: Dept. of Electr. Eng., Texas A&M Univ., College Station, TX, USA

**Conference Title**: 2000 Power Engineering Society - Summer Meeting

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; environmental factors; power system economics

Identifiers: deregulated power markets; ancillary services; power market commodities auctions coordination; multi-objective solutions; environmental requirements; emission allowance auction; pollution quotas trading

**Abstract**: In deregulated power markets, besides auctions for energy, auctions for other commodities such as ancillary services an also anticipated. Meanwhile, in order to satisfy the environmental requirements for the industry, the authors propose an auction of emission allowance to trade pollution quotas. The energy, the ancillary services and the emission allowances are procured simultaneously. This coordination problem is formulated and solved as a multi-objective problem. (11 Refs)

## The potential of distributed generation to provide ancillary services

**Author(s):** Joos, G.; Ooi, B.T.; McGillis, D.; Galiana, F.D.; Marceau, R.

**Author Affiliation**: Dept. of Electr. & Comput. Eng., Concordia Univ., Montreal, Que., Canada

**Conference Title**: 2000 Power Engineering Society - Summer Meeting

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: commutation; distribution networks; electric power generation; invertors; load flow control; power convertors; power harmonic filters; power supply quality; power system control; power system harmonics

**Identifiers**: distributed generation; ancillary services; electric power quality; availability; electric industry deregulation; services unbundling; spinning reserve equivalent; AC bus voltage support; power electronic interface; real power control; reactive power; power quality; voltage sag compensation; harmonic filtering; power converter interface; self commutated converters; power flow control; inverters

**Abstract**: The growing concerns regarding electric power quality and availability have led to the installation of more and more distributed generation. In parallel and in the context of an accelerating trend towards deregulation of the electric industry, the unbundling of services, many grouped under ancillary services, should create a market for some of these services. This paper discusses the potential of distributed generation (DG) to provide some of these services. In particular, DG can serve locally as the equivalent of a spinning reserve and voltage support of the AC bus. The main types of distributed generation with emphasis on the power electronic interface and the configurations appropriate to provide ancillary services are reviewed. The flexibility and features provided by the power electronic interface are illustrated. In addition to control of the real power, other functions can be incorporated into the design of the interface to provide services, such as reactive power, and resources associated with power quality. These include voltage sag compensation and harmonic filtering. The implications on the design of the power converter interface are discussed. (7 Refs)

## Bilateral market for load following ancillary services

**Author(s):** Nobile, E.; Bose, A.; Tomovic, K.

**Author Affiliation**: Dept. of Electr. Eng. & Comput. Sci., Washington State Univ., Pullman, WA, USA

**Conference Title**: 2000 Power Engineering Society - Summer Meeting

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; load (electric); power system economics

**Identifiers**: bilateral market; load following ancillary services; generators; transmission equipment; control equipment; system security; reliable operations

**Abstract**: Ancillary services are those services performed by generators, transmission and control equipment, which are necessary to support basic services and to maintain reliable operations and system security. In this paper, we focus our attention on one of these services, load following, and propose a competitive way to provide this service through bilateral contracts between supplier and customer. (8 Refs)

## Transmission loss compensation in multiple transaction networks

**Author(s):** Shu Tao; Gross, G.

**Author Affiliation:** Dept. of Electr. & Comput. Eng., Illinois Univ., Urbana, IL, USA

**Journal**: IEEE Transactions on Power Systems vol.15, no.3 p.909-15; Publisher: IEEE, Publication Date: Aug. 2000

**Language**: English

**Treatment**: Theoretical (T)

**Descriptors**: compensation; losses; power transmission

**Identifiers**: transmission loss compensation; multiple transaction networks; equivalent loss compensation; physical-flow allocation; loss compensation service; central independent grid operator; value-added service; linear program formulation; self-acquisition service; IEEE 118-bus system; IEEE 300-bus system; ancillary services

**Abstract**: We develop and apply the equivalent loss compensation concept to construct flexible and effective procedures for compensating losses in a multi-transaction network. The procedures are developed in the multiple transaction framework and are based on the physical-flow allocation of losses among the transactions. The proposed procedures provide transactions the choice of selecting self-acquisition of loss compensation at designated bus(es) or to purchase the loss compensation service from a central independent grid operator (IGO). The IGO can provide loss compensation as a value-added service to its transmission customers, IGO-acquisition of loss compensation uses a linear program formulation in which network constraints are explicitly represented to determine the solution which gives the least-price at which the IGO can acquire the service. The self-acquisition service may co-exist side-by-side with the IGO-acquisition and any physically feasible combination of these acquisition schemes is possible. The effectiveness and flexibility of the procedures are illustrated with numerical results using the IEEE 118- and 300-bus systems. (8 Refs)

## Designing ancillary services markets for power system security

**Author(s):** Bolton Zammit, M.A.; Hill, D.J.; Kaye, R.J.

**Author Affiliation**: Sch. of Electr. & Inf. Eng., Sydney Univ., NSW, Australia

**Journal**: IEEE Transactions on Power Systems vol.15, no.2 p.675-80; Publisher: IEEE, Publication Date: May 2000

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; power generation dispatch; power system control; power system economics; power system security; voltage control

**Identifiers**: ancillary services markets design; power system security; competitive electricity markets; electricity spot market; repeatable market rules; transparent market rules; least overall cost; voltage control; nine bus test system; power generation dispatch; power system economics

**Abstract**: A framework for ensuring power system security in competitive electricity markets is developed, based on a market for ancillary services. The ancillary services market is designed to integrate with a spot market for electricity, and market operation is based on a set of transparent and repeatable market rules. These rules provide the analytical basis for the algorithm that determines which ancillary service offers should be accepted to optimize system security for least overall cost. The approach is demonstrated for voltage control of a nine bus test system. (29 Refs)

## Reactive power pricing: a conceptual framework for remuneration and charging procedures

**Author(s):** Barquin Gil, J.; San Roman, T.G.; Alba Rios, J.J.; Sanchez; Martin, P.

**Author Affiliation**: Inst. de Investigacion Tecnologica, Univ. Pontificia Comillas, Madrid, Spain

**Journal**: IEEE Transactions on Power Systems vol.15, no.2 p.483-9; Publisher: IEEE, Publication Date: May 2000

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: costing; electricity supply industry; power system economics; power transmission control; reactive power; voltage control

**Identifiers**: reactive power pricing; charging procedures; reactive power supply; electrical sector regulation; competitive markets; ancillary services procurement; ancillary services remuneration; transmission network voltage control; security levels; voltage profile management; reactive dispatch; voltage regulation; marginal pricing; competitive environment

**Abstract**: A new electrical sector regulation is being implemented in different countries all over the world. The new regulation stresses the role of competitive markets for the procurement and remuneration of ancillary services. Among these services stand the ones associated with reactive power supply and transmission network voltage control in order to maintain the required system security levels. The object of this paper is twofold. On one hand, reactive power supply and voltage control services, which today are bundled, are decomposed in two types: (i) voltage profile management and reactive dispatch, and (ii) voltage regulation. A theoretical approach based on marginal pricing is proposed in order to clarify the principles to remunerate the suppliers and to charge the consumers of these services. On the other hand, a practical organization of reactive supply and voltage service markets is presented to be implemented in a competitive environment. (12 Refs)

## Optimum VAr support procurement for maintenance of contracted transactions

**Author(s):** Jin Zhong; Bhattacharya, E.

**Author Affiliation**: Dept. of Electr. Power Eng., Chalmers Univ. of Technol., Goteborg, Sweden

**Conference Title**: DRPT2000 - International Conference on Electric Utility Deregulation and Restructuring and Power Technologies. Proceedings

**Language**: English

**Treatment**: Practical (P); Theoretical (T)

**Descriptors**: contracts; electricity supply industry; load flow; losses; power systems; reactive power

**Identifiers**: optimum VAr support procurement; contracted transactions maintenance; ependent system operator; deregulated electricity market; bilateral contracts; generator reactive capability; optimal power flow; optimum reactive power procurement; network losses minimisation; CIGRE 32 node network; ancillary services

**Abstract**: This paper models and addresses the various issues associated with reactive power procurement by an independent system operator functioning in a deregulated electricity market dominated by bilateral contracts. The reactive capability of a generator is modeled within an optimal power flow (OPF) framework. The optimum procurement of reactive power is obtained considering

minimization of network losses and deviation from contracted transactions. The CIGRE 32 node network which approximately represents the Swedish system is used for the studies. (6 Refs)

## Electricity market regulations and their impact on distributed generation

**Author(s):** Ackermann, T.; Andersson, G.; Soder, L.

**Author Affiliation**: Dept. of Electr. Power Eng., R. Inst. of Technol., Stockholm, Sweden

**Conference Title**: DRPT2000 - International Conference on Electric Utility Deregulation and Restructuring and Power Technologies. Proceedings

**Language**: English

**Treatment**: General, Review (G)

**Descriptors**: electric power generation; electricity supply industry; legislation

**Identifiers**: electricity market regulations; distributed generation impact; legal framework; competitive electricity markets; regulatory approaches; power exchanges; balance services; ancillary services; regulatory aspects

**Abstract**: Distributed generation (DG) has attracted a lot of attention recently and might become more important in future power generation systems. As different definitions are used worldwide, the paper briefly discusses the definition of DG. The future development of DG, however, will, to a not insignificant part, depend on the legal framework. As the legal framework can vary significantly for different competitive electricity markets, this paper briefly identifies and analyses some variations in the regulatory approaches, e.g. for power exchanges, balance services and ancillary services, in different countries. It also illustrates the influence of market regulations on the development of distributed power generation. Based on this analysis, it can be concluded that regulatory aspects might decisively influence the development of distributed power generation. (24 Refs)

## Ancillary services-to use for whom?

**Author(s):** Gjengedal, T.; Kvennas, O.

**Author Affiliation**: STATKRAFT SF, Hovik, Norway

**Conference Title**: DRPT2000 - International Conference on Electric Utility Deregulation and Restructuring and Power Technologies. Proceedings

**Language**: English

**Treatment**: Economic aspects (E); General, Review (G)

**Descriptors**: electricity supply industry; load flow; management; power system economics; tariffs

**Identifiers**: deregulated power systems; Norway; ancillary services management; generators; loads; pricing methods; trading methods

**Abstract**: The paper has discussed ancillary services management in deregulated power systems. The paper has quantified which services that could be provided by generators and loads, but also how the services intersect with different markets. Examples from Norway are presented, and pricing and trading methods are discussed. (7 Refs)

## Web-based framework for electricity market

**Author(s):** Marmiroli, H.; Suzuki, H.

**Author Affiliation**: Power Syst. & Transmission Eng. Center, Mitsubishi Electr. Corp., Tokyo, Japan

**Conference Title**: DRPT2000 - International Conference on Electric Utility Deregulation and Restructuring and Power Technologies. Proceedings

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: digital simulation; electricity supply industry; information resources; Java; power engineering computing; power transmission; software agents

**Identifiers**: electricity market; Web-based framework; business transaction model; Internet-based information architecture; open electricity market; energy trade management; ancillary services management; day-ahead market; Internet infrastructure; efficiency; transparency; equitability; optimization process; power exchange; market information analysis; simulator; decision-making tool; market participants; JAVA distribution architecture; JAVA servlets

**Abstract**: This paper describes a business transaction model and the Internet-based information architecture for the open electricity market. A power exchange is assumed to coordinate and manage the trade of energy and ancillary services in the day-ahead market through the Internet infrastructure. Indispensable characteristics for the exchange mechanism are efficiency, transparency and equitability; in order to guarantee these requirements we introduce an optimization process operated by the power exchange which ensures an appropriate evaluation of the generation offers for the available resources under some operational constraints. Further, in this paper, a market simulation approach is described. Several agents are developed to simulate offer strategies. Each agent automatically analyzes market information, and based on its own characteristic, submits an offer to the power exchange. The simulator can be utilized as a decision-making tool for market participants. The system is implemented utilizing JAVA distribution architecture, such as Web technologies and JAVA servlets. (13 Refs)

## California's restructuring optimization models

**Author(s):** Gribik, P.

**Author Affiliation**: NONE LISTED

**Conference Title**: 2000 IEEE Power Engineering Society - Winter Meeting.

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: electricity supply industry; optimization; power system economics

**Identifiers**: electricity markets restructuring; optimization models; California; mandatory pools; bilateral transaction; sellers; buyers; energy; ancillary services; transmission; marginal-cost-based prices

**Abstract**: Summary form only given as follows. Many approaches to restructuring electricity markets employ optimization models as the core of their market engines. Optimization models are used in markets based on mandatory pools as well as some markets based on bilateral transaction. The optimization models determine winning sellers and buyers of various commodities (energy, ancillary services, transmission, etc.) and set marginal-cost-based prices for the transactions. For the markets to produce economically meaningful prices, the optimization models of the market must be designed carefully and have appropriate range. California's restructuring is used to illustrate how the optimization models may be formulated to achieve market characteristics desired by the participants. It is also be used to illustrate potential dangers. Experience with the California market is used to illustrate how energy marketers can bid for transmission access in forward markets without commingling the energy marketers in a common pool. California's ancillary service markets are used to illustrate the potential for distortion of marginal cost signals when a single resource can bid to provide capacity in several markets that are not optimized simultaneously. (0 Refs)

## Market based ancillary services for ramping

**Author(s):** Bakken, B.H.; Petterteig, A.; Nystad, A.K.

**Author Affiliation**: SINTEF Energy Res., Trondheim, Norway

**Conference Title**: 2000 IEEE Power Engineering Society - Winter Meeting.

**Language**: English

**Treatment**: Economic aspects (E); General, Review (G)

**Descriptors**: electricity supply industry; HVDC power transmission; power transmission control; power transmission economics

**Identifiers**: market-based ancillary services; power system; Norway; HVDC connections; ramping; extraordinary fast reserve; ancillary services; decentralised market structure; generation capacity; fast load changes

**Abstract**: In a few years, the Norwegian power system will experience substantially increased strain due to operation of four HVDC connections to Continental Europe. As a first step to meet the new challenges, the Norwegian system operator will introduce two new market-based ancillary services called `ramping' and `extraordinary fast reserve'. When all four connections are in operation, introduction of a special AGC scheme where selected units follow the HVDC connections is considered. This paper presents the two new ancillary services, how they will be used to ensure generation capacity to follow fast load changes on the HVDC connections, and further how they can be extended to an AGC scheme while retaining the decentralised market structure. Examples of current system operation are also shown. (2 Refs)

## Role of the system operator in the unbundled and market environment

**Author(s):** Maslo, K.; Reznicek, V.; Svejnar, P.

**Author Affiliation**: AFFILIATION: Trans. Grid Div., Czech Power Co., Praha, Czech Republic

**Conference Title**: International Conference on Large High Voltage Electric Systems

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: electricity supply industry; legislation; power systems

**Identifiers**: power system operator; market environment; unbundled environment; industry regulations; government regulations; system integrity; system security; ancillary services; data exchange

**Abstract**: The system operator plays an important role in new conditions. The basic framework for system operator, government and industry regulations, is introduced. The significance of so-called system services is obvious for system integrity and security. The new idea of decomposition into system function (provided by system operator) and ancillary services (provided by system users) is presented. The basic concept of data exchange is presented as well. (2 Refs)

## The market for spinning reserve and its impacts on energy prices

**Author(s):** Jinxiang Zhu; Jordan, G.; Ihara, S.

**Author Affiliation**: Power Syst. Energy Consulting, GE Energy Services, Schenectady, NY, USA

**Conference Title**: 2000 IEEE Power Engineering Society - Winter Meeting.

**Language**: English

**Treatment**: Economic aspects (E); Practical (P)

**Descriptors**: costing; electricity supply industry; power system economics; power transmission

**Identifiers**: shadow price; spot price; independent system operators; spinning reserve market; energy prices; transmission owners; ancillary services; transmission open access; power quality; system reliability; synchronized power; synchronized units; pumped hydro units; interruptible load; transmission congestion; spinning reserve reallocation; California; PJM; New York; New England; transmission constraints

**Abstract**: To make the energy market reliable and transactions deliverable, transmission owners must provide the necessary ancillary services that are critical to ensure transmission open access and power quality. Spinning reserve is one of the important ancillary services to maintain system reliability in the case of a contingency. By definition, spinning reserve is the unloaded section of synchronized power that is able to respond immediately to serve the load, and is fully available within ten minutes. Since the spinning reserve must be provided by synchronized units (pumped hydro units and/or interruptible load for some ISOs), these units can either provide energy or spinning reserve or both based on their bids. Study shows that spinning reserve requirements have significant impacts on the energy market. Transmission congestion may reallocate spinning reserve among generators to release the overloads. Different market structures for spinning reserve have been investigated and illustrated by a small example. Different ISO's (California, PJM, New York, and New England) practices on spinning reserve market have been summarized and commented upon. A new spinning reserve market structure is proposed to better utilize the available resources to meet load and spinning reserve requirement with the transmission constraints. (11 Refs)

## Efficient use of generator resources in emerging electricity markets

**Author(s):** Flynn, M.E.; Walsh, M.P.; O'Malley, M.J.

**Author Affiliation**: Dept. of Electron. & Electr. Eng., Univ. Coll. Dublin, Ireland

**Journal**: IEEE Transactions on Power Systems vol.15, no.1 p.241-9; Publisher: IEEE, Publication Date: Feb. 2000

**Language**: English

**Treatment**: Economic aspects (E); Theoretical (T)

**Descriptors**: costing; electricity supply industry; energy resources; Hopfield neural nets; power generation economics; power generation scheduling; tariffs

**Identifiers**: emerging electricity markets; efficient generator resources use; ancillary services pricing; unit cost curves; unit scheduling; operating modes; augmented Hopfield neural network; reserve prices; ramping prices

**Abstract**: In the emerging electricity market, generators sell ancillary services as well as energy to the system operator. Pricing of ancillary services makes the scheduling of units more difficult due to the resulting unit cost curves. The new climate will encourage generators to exploit the flexibility of their units in terms of operating modes. This paper uses the augmented Hopfield neural network to deal with

ancillary service prices, specifically reserve and ramping prices, submitted by generators and to schedule units with a choice of operating modes. (20 Refs)

## Decomposition model and interior point methods for optimal spot pricing of electricity in deregulation environments

**Author(s):** Xie, K.; Song, Y. H.; Stonham, J.; Erkeng Yu; Guangyi Liu

**Author Affiliation**: Dept. of Electr. Eng., Brunel Univ., Uxbridge, UK

**Journal**: IEEE Transactions on Power Systems vol.15, no.1 p.39-50; Publisher; IEEE, Publication Date: Feb. 2000

**Language**: English

**Treatment**: Theoretical (T)

**Descriptors**: costing; electricity supply industry; load dispatching; load flow; Newton method; power system economics; reactive power

**Identifiers**: interior point methods; optimal electricity spot pricing; deregulation environments; optimal nodal specific real-time prices; reactive power; active power; ancillary services; spinning reserve; voltage control; security control; classical economic dispatch; Newton OPF methods; IEEE 5-bus system; IEEE 30-bus system

**Abstract**: In this paper, an integrated optimal spot pricing model is presented first. The proposed model includes the detailed derivation of optimal nodal specific real-time prices for active and reactive powers, and the method to decompose them into different components corresponding to generation, loss, and many selected ancillary services such as spinning reserve, voltage control and security control. The features of the proposed model are discussed in relationship to existing pricing models and classical economic dispatch. The model is then implemented by modifying existing Newton OPF methods through interior point algorithms, which can effectively avoid "go" "no go" gauge (i.e. highly volatile) in the calculation of spot prices. Case studies on 5-bus and IEEE 30-bus systems are reported to illustrate the proposed method. (26 Refs)

## Market-based congestion management

**Author(s):** Sun, D.

**Author Affiliation**: ALSTOM ESCA, Bellevue, WA, USA

**Conference Title**: 2000 IEEE Power Engineering Society - Winter Meeting

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: electricity supply industry; load flow control; power system interconnection; power transmission control

**Identifiers**: electricity products trading; market-based congestion management; electricity markets design; competitive electricity markets; electric power industry; market economics; power system operating characteristics; ancillary services scheduling; transmission congestion management; congestion management rules

**Abstract**: Trading electricity products is significantly different from trading other commodities. The differences must be recognized in the design of electricity markets. Effective operation of competitive electricity markets requires judicious integration of the fundamentals of market economics with physical characteristics of operating the power system. Among the market design issues most unique to electricity markets are managing transmission congestion and scheduling ancillary services. In this paper, the

author summarizes effective congestion management rules that have been developed and deployed in physically operational markets. (0 Refs)

## An overview of electric power industry restructuring worldwide

**Author(s):** Shirmohammadi, D.

**Author Affiliation**: Perot Syst. Corp., Los Angeles, CA, USA

**Conference Title**: 2000 IEEE Power Engineering Society - Winter Meeting

**Language**: English

**Treatment**: Economic aspects (E); General, Review (G)

**Descriptors**: electricity supply industry; power system control; power system economics; power system planning

**Identifiers**: electric power industry restructuring; overview; market structures; power exchanges; independent system operators; planning responsibilities; energy auction process; ancillary services auction; energy scheduling; transmission congestion management; real-time monitoring; real-time operations; real-time control; financial settlements; financial clearing

**Abstract**: Summary form only given, as follows. This presentation broadly covers the following aspects of restructured electric power markets worldwide: (1) market structures; (2) broad structure of power exchanges (PXs) and independent system operators (ISOs); (3) planning responsibilities of PXs and ISOs; (4) energy auction process; (5) ancillary services auction; (6) energy scheduling; (7) transmission congestion management; (8) real-time monitoring, operations and control by ISOs; and (9) financial settlements and clearing. (0 Refs)

## Congestion management methods for energy trade

**Author(s):** Brauner, G.

**Author Affiliation**: Inst. of Power Syst., Wien Univ., Austria

**Conference Title**: Proceedings of the 11th International Conference on Power System Automation and Control

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: costing; electricity supply industry

**Identifiers**: congestion management methods; energy trade; electric power industry liberalization; European Union; unbundling; competition; cooperation; network operation; generation scheduling; market price; system operator; ancillary services; reduced investments; spot market

**Abstract**: The liberalization of the electric power industry in the EU, beginning from 1999 until total liberalization in 2007 results in major changes, mainly by unbundling, competition and partly cooperation. Seen from network operation, the task is more difficult, as generation scheduling is influenced by market price, and the system operator has only the ability to influence generation via ancillary services. The cost situation of utilities after liberalization results in reduced investments for the grid leading to higher system loading. Together with a developing spot market, congestion management by financial or technical instruments is of increasing importance. (1 Refs)

## Providing competitive ancillary services through efficient market structures

**Author(s):** Bonvini, B.; Denegri, G.B.; Invernizzi, M.; Scarpellini, P.

**Author Affiliation**: Dept. of Electr. Eng., Genoa Univ., Italy

**Conference Title:** PowerTech Budapest 99

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: electricity supply industry; frequency control; power system control

**Identifiers**: competitive ancillary services; market structures; electric companies; economic pressure; deregulation; power markets creation; active power services; spinning reserve; frequency regulation

**Abstract**: Most electric companies are facing structural changes due to increasing economic pressure towards deregulation and creation of power markets. One of the most critical issues still remaining open in this context is providing ancillary services competitively. The main focus of the paper is the implementation of a framework for the valuation of ancillary services that market participants are selling or buying, so that the optimal prices at which each service is exchanged will be more easily agreed by the parties. The quantifying method proposed in the paper is based on the relationship between the availability (the use) of the generic ancillary service and the state (the transition) the system is presently experimenting. The efficacy of the method is tested with reference to different active power services, given by spinning reserve and frequency regulation. (0 Refs)

## IT solutions and examples in deregulated marketplaces

**Author(s):** Urban, M.; Vierheilig, N.; Santos, M.; Moser, A.

**Author Affiliation**: Power Syst. Control Subdiv, Siemens AG, Nuremberg, Germany

**Conference Title:** PowerTech Budapest 99

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: electricity supply industry; information technology; power system control; power transmission

**Identifiers**: IT solutions; deregulated marketplaces; power industry; deregulation; privatization; competition; 3rd party access; transmission company; independent system operator; generation companies; nondiscriminatory access; transmission facilities access; ancillary services access; reliable system operation; distribution company; software applications; control center applications; Scandinavia; deregulated US industry; Open Access Same Time Information System; available transfer capability; energy trading; scheduling tools

**Abstract**: The power industry in many parts of the world is undergoing dramatic changes: deregulation, privatization, competition and 3rd party access are the keywords. Its the transmission company's (TransCo) and independent system operator's (ISO) responsibility to enable competition among the generation companies (GenCos) by providing nondiscriminatory access to the transmission facilities, ancillary services as well as a secure and reliable system operation. The distribution company (DisCo) has to guarantee free access to the distribution network to promote the competition on the supply side. In order to accomplish their new challenges, the new types of utilities need new IT solutions and new software applications. As examples for these new solutions, this paper presents successfully implemented new control center applications for an ISO in the deregulated US industry as well as for GenCos and DisCos in Scandinavia. The focus is on the applications available transfer capability (ATC) and Open Access Same Time Information System (OASIS) supporting the ISO as well as energy trading and scheduling tools for GenCos. Integrated IT solutions are implemented to improve the competitive

position of the companies by supporting complete business processes. (0 Refs)

## Power system automatic generation control revised from the open trading perspective

**Author(s):** Aresi, R.; Delfino, B.; Fornari, F.; Massucco, S.; Morini, A.

**Author Affiliation**: Dept. of Electr. Eng., Genova Univ., Italy

**Conference Title**: PowerTech Budapest 99

**Language**: English

**Treatment**: Practical (P)

**Descriptors**: electricity supply industry; frequency control; power generation control; power system control

**Identifiers**: power system automatic generation control; open trading perspective; power system operation; power system management; electric industry restructuring process; long-term bilateral contracts; secondary services; ancillary services; load-following; secondary frequency contro; CIGRE test system

**Abstract**: The paper describes the significant changes expected in power system operation and management required by the restructuring process of electric industry. The problem of automatic generation control (AGC) is addressed under the open trading perspective. The fundamental concepts of AGC are recalled and the possible modifications are presented. The co-existence of a primary service predominantly based on long-term bilateral contracts and of secondary services (or ancillary services) such as load-following and secondary frequency control is highlighted. Different AGC solutions are theoretically reported and supported by simulations on a CIGRE test system. (0 Refs)