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# Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation

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## Disclaimer

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Prepared for

Office of Electric Reliability
Federal Energy Regulatory Commission

Prepared by

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The project team acknowledges Joseph H. McClelland, Director of the Office of Electric Reliability, for his recognition and conceptualization of the importance of frequency response as a metric to assess the integration of variable renewable generation and his initiation of this project. The project team also acknowledges the significant technical contributions of Joe and FERC staff, including Robert Snow, Frank Macedo, Chris Mak, Eddy Lim, and Jerry Taylor.

In addition, the project team acknowledges the Western Electricity Coordinating Council (WECC), the Electric Reliability Council of Texas (ERCOT), and the Eastern Interconnection Reliability Assessment Group for providing the interconnection-wide system models that were used in the study. Each was helpful and forthcoming in answering technical questions and in some cases reviewing simulation results.

The project team also acknowledges staff at the Bonneville Power Administration, California Independent System Operator (CAISO), ERCOT, and the Midwest Independent Transmission System Operator (MISO) for participating in interviews in which they shared perspectives and experiences related to integration of variable renewable generation. Staff at these organizations answered all of our questions, reviewed our interview notes, and provided follow-up materials. Finally, the project team acknowledges staff at EirGrid, EnerginetDK, and Rede Eléctrica Nacional who provided valuable information on European practices and perspectives related to integration of variable renewable generation.

The project team alone, however, bears sole responsibility for technical adequacy of the analysis methods and the accuracy of the study results.

# Table of Contents

## List of Figures

## List of Tables:

## Acronyms:

| | |
|---|---|
| AGC | Automatic generation control |
| ACE | Area control error |
| BPA | Bonneville Power Administration |
| CAISO | California Independent System Operator |
| CPS | Control performance standard |
| DCS | Disturbance control standard |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| GW | Gigawatt |
| Hz | Hertz |
| mHz | Millihertz |
| LaaR | Load acting as Resource |
| LBNL | Lawrence Berkeley National Laboratory |
| MISO | Midwest Independent Transmission System Operator |
| MW | Megawatt |
| NERC | North American Electric Reliability Corporation |
| PFR | Primary frequency response |
| PSERC | Power Systems Engineering Research Center |
| REN | Rede Eléctrica Nacional |
| RMS | Root mean square |
| UFLS | Under-frequency load shedding |
| WECC | Western Electricity Coordinating Council |

## Synopsis

An interconnected electric power system is a complex system that must be operated within a safe *frequency* range in order to reliably maintain the instantaneous balance between generation and load. This is accomplished by ensuring that adequate resources are available to respond to expected and unexpected imbalances and restoring frequency to its scheduled value in order to ensure uninterrupted electric service to customers. Electrical systems must be flexible enough to reliably operate under a variety of "change" scenarios. System planners and operators must understand how other parts of the system change in response to the initial change, and need tools to manage such changes to ensure reliable operation within the scheduled frequency range.

This report presents a systematic approach to identifying metrics that are useful for operating and planning a reliable system with increased amounts of variable renewable generation which builds on existing industry practices for frequency control after unexpected loss of a large amount of generation. The report introduces a set of metrics or tools for measuring the adequacy of frequency response within an interconnection. Based on the concept of the *frequency nadir*, these metrics take advantage of new information gathering and processing capabilities that system operators are developing for wide-area situational awareness. Primary frequency response is the leading metric that will be used by this report to assess the adequacy of primary frequency control reserves necessary to ensure reliable operation. It measures what is needed to arrest frequency decline (i.e., to establish a frequency nadir) at a frequency higher than the highest set point for under-frequency load shedding within an interconnection. These metrics can be used to guide the reliable operation of an interconnection under changing circumstances.

The frequency response metrics introduced here can be used not just to manage the integration of variable renewable generation but also to guide and gauge the extent and success of reliable integration of any new resource into an interconnection.[1] They can be used to map a transition path when major changes are made to existing resources such as conventional plant retirements or de-ratings.

Wind is expected to be a major new source of electricity generation to each of the interconnections in the near term, so this study tested and validated the frequency response metrics in simulations of the generation and transmission infrastructures that system operators expect to have in place in 2012. Wind generation presents challenges for the reliable operation of the electric power system, in part because the electricity generated from wind is more variable than electricity generated from conventional sources. The purpose of this report however, was not to specifically determine the theoretical amount of wind generation that can be reliably integrated into an interconnection nor of other types of generation that industry may decide to build. Rather, it presents and validates a tool that can be used to assess and plan for the operational requirements for reliable integration of variable renewable generation. In order to validate the concept, it was applied to each of the interconnections. This approach showed that the wind generation capacity projected for 2012 in the Western and Texas interconnections can be reliably integrated. If higher levels of wind generation are integrated, this tool can be used to

[1] The term variable renewable generation refers to electricity generation facilities whose energy source: 1) is renewable; 2) cannot be stored by the facility owner or operator; and 3) has variability that is beyond the control of the facility owner or operator. This includes wind and solar generation facilities and certain hydroelectric resources.

determine changes in primary and secondary frequency controls that will be required in addition to transmission identified by other studies. The tool can also be used in operating and planning the transmission system and designing markets to fully integrate and reliably operate the mix of generation and transmission resources that are deployed in the future. Further, the metrics can be used to identify the appropriate use of new technologies such as demand response and energy storage devices in achieving reliable operation.

As part of its responsibility to oversee the reliability of the nation's bulk power system, the Federal Energy Regulatory Commission (FERC) staff commissioned Lawrence Berkeley National Laboratory (LBNL) to determine if frequency response is an appropriate predictive metric to assess the level of renewable resources that can be reliably added to the power grid. [2]

FERC staff commissioned LBNL to study how a critical aspect of reliability -- the control of power system frequency during the period immediately following the sudden loss of a large conventional power plant –can be better measured to assess the adequacy of frequency control in the interconnections currently and be used to manage the reliable integration of new resources, including variable renewable generation. Specifically, the objectives of this study are:

1. To determine whether metrics for frequency response[3] could be used to assess the reliability impacts of integrating variable renewable generation;
2. If so, to use these metrics to assess the potential reliability impact of new variable renewable generation on the electric power system, by interconnection, following the sudden, instantaneous loss of large conventional power plants;[4] and
3. To identify what further work and studies are necessary to quantify and address any reliability impacts associated with the integration of variable renewable generation.

Several aspects of this scope must first be clarified in order to understand the study's methods, findings, and recommendations:

1. FERC did not ask LBNL to study the type, amount, cost or timing of transmission investments required to integrate variable renewable generation reliably because it is already understood that physically integrating increased wind generation will require significant transmission infrastructure investment. Other studies have and will continue to examine these requirements. This report complements these studies by focusing on the operational requirements necessary to ensure that whatever transmission system is in place can be operated reliably.
2. FERC asked LBNL to study frequency response, or primary frequency control. Accordingly, this study focuses on the resiliency of the power system following the sudden, instantaneous loss of large conventional power plants. Other studies have and will continue to examine requirements for managing the variability of wind generation

[2] The scope of this project was broadened from the original scope announced in May, 2009 as the research progressed, revealing the general applicability of frequency response metrics to analyze a broad range of changes that a complex interconnected electric system must manage to ensure reliability.

[3] Frequency response is a technical term used by the industry to describe how a power system has performed in responding to the sudden loss of generation, which is one of the most important threats to reliability.

[4] This assumes that the system is designed and operated such that a common mode transmission failure will not result in the loss of large quantities of either variable renewable or conventional generation.

output through secondary frequency control reserves, which occurs much more slowly than the sudden and unexpected events analyzed here. This study, however, complements these studies by introducing the additional measures that must be taken to ensure that power systems with large amounts of wind generation can withstand the sudden loss of large amounts of conventional generation.

3. FERC asked LBNL to study wind generation because it is expected to be the dominant form of variable renewable generation over the near term. The methods and metrics employed by this study can and should be applied to study the operational requirements for reliability posed by all anticipated changes to the electric power system.

**Key Findings**

1. Reliability practices seek to ensure that, following the sudden and unplanned loss of large conventional generators, an interconnection will continue to deliver electricity to customers without interruption. Ensuring reliability in these circumstances depends on the continuous availability of a critical component of operating reserves called primary frequency control.[5]
2. The requirements for primary frequency control can be assessed using three metrics that measure how primary frequency control reserves are expected to perform (in planning studies) as well as how they have performed (in after the fact analysis) in arresting and stabilizing frequency following the sudden loss of conventional generation.[6] The first metric, called frequency nadir, is a direct measure of how close a system has come to interrupting the delivery of electricity to customers. The second metric, called nadir-based frequency response, relates the amount of generation lost to the decline in frequency until arrested. The third metric, called primary frequency response, measures the power delivered by primary frequency control during critical periods before and after the frequency nadir is formed.
3. The requirements for adequate primary frequency control reserves depend on: 1) the events (i.e., the amount of conventional generation that might be lost) that the interconnection is expected to withstand; 2) the frequency set points at which under-frequency load shedding[7] is deployed within an interconnection; and 3) the efficacy of primary frequency control actions in arresting the rapid frequency decline following these events before these set points are reached.
4. Increased variable renewable generation is not expected to affect the first two of these factors. The rapid ramping[8] of variable renewable generation output is not considered an event comparable to the sudden loss of large conventional generators and variable renewable generation is not expected to affect the set points for under-frequency load shedding.

[5] See Section 2.2 for a description of primary frequency control.

[6] See Section 2.4 for descriptions of the frequency response metrics.

[7] See Section 2.2 for a description of under-frequency load shedding.

[8] Variable renewable generation output can be expected to decrease each day during the morning time frame when electrical demand is increasing. The combination can produce ramps higher than what has been experienced in the past.

5. Increased variable renewable generation will have four impacts on the efficacy of primary frequency control actions:
    a. Lower system inertia.[9] While this effect is expected to be minor compared to the other three discussed next, other things being equal, lower system inertia would increase the requirements for primary frequency control reserves in order to arrest frequency at the same nadir following the sudden loss of generation.
    b. Displacement of primary frequency control reserves. The amount of primary frequency control reserves that are on line and always available may be reduced as the conventional generation-based sources for these reserves are displaced by variable renewable generation, which currently does not provide primary frequency control.
    c. Affect the location of primary frequency control reserves. Related to b above, the resulting re-dispatch of available conventional generation that currently provides primary frequency control may lead to transmission bottlenecks that prevent effective delivery of primary frequency control when it is needed.
    d. Place increased requirements on the adequacy of secondary frequency control reserves.[10] The demands placed on slower forms of frequency control, called secondary frequency control reserves, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary reserves, primary frequency control reserves (that are set-aside to respond to the sudden loss of generation) will be used to make up for the shortfall. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserves than has been the case in the past because we believe this is likely to emerge as the most significant frequency-response-based impact of variable renewable generation on reliability.
6. The declining quality of frequency control in the U.S. interconnections is currently a significant reliability concern. It is widely understood that the integration of variable renewable generation is not related to and therefore has not been a cause or contributor to the declines observed over the past decade.
7. Recent studies of renewables integration within the U.S. have focused on increased requirements for secondary frequency control (regulation and load following), but only to a limited extent if at all on requirements for primary frequency control.
8. International experiences, in particular from countries with large wind penetrations, provide selected, yet important insights for the U.S. Still, the interconnections within which these countries operate and the operating practices of the interconnections differ from those in the U.S.
9. The academic literature has begun to document frequency response implications of the very low amounts of inertia provided by currently installed wind generation technologies, but no studies of these impacts have been performed using validated models of U.S. interconnections.
10. For the Western Interconnection, assuming operating reserve conditions that are representative of current practices and that are used in daily operations (which are higher

[9] See Section 2.2 for a description of system inertia.

[10] See Section 2.2 for a description of secondary frequency control.

than the minimum levels that are allowable under current operating procedures), our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected by 2012. The system model we studied included 9 GW of installed wind generation capacity, which based on an assumed 35% capacity factor and the North American Electric Reliability Corporation's (NERC) estimate of electricity demand in 2012 could supply approximately 3 percent of the interconnection's expected electricity requirements in 2012.

11. For the Texas Interconnection, assuming operating reserve conditions that reflect the lower range of the current operating practices, our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected by 2012. The system model we studied included 14.4 GW of installed wind generation capacity, which based on an assumed 35% capacity factor and NERC's estimate of total electricity demand could supply approximately 13 percent of the interconnection's expected electricity requirements in 2012. Notably, the results depend on the completion of significant portions of the new transmission that has been planned through the Competitive Renewable Energy Zone process.
12. Our study of the Texas Interconnection also confirms the effectiveness of the interconnection's reliance on a specialized form of demand response to control frequency following the sudden loss of generation. Our simulation studies find that this program, whose principles may also be applicable within the Western and Eastern Interconnections, is an effective complement to the primary frequency control reserves currently provided by generators.
13. For the levels studied, a principal finding from our simulations of the Western and Texas Interconnection is that the rapid delivery of power via primary frequency control actions is more important than the amount of wind generation in determining the frequency nadir. The effect of increased wind generation in lowering system inertia is not significant compared to the effects of primary frequency control actions. The simulations also suggest that focused attention on the quality of primary frequency control actions, provided by generator governors and, in the Texas Interconnection, frequency-responsive demand response, can readily off-set the effects of increased wind generation on system inertia.
14. We were not able to conduct simulation studies of increased levels of variable renewable generation in the Eastern Interconnection. We found that, using the system model that was provided, we could not reproduce the frequency response of the Eastern Interconnection to a recent recorded event involving the sudden loss of a large amount of generation. The simulation results predict that the frequency response of the interconnection is much more robust than the frequency response that has been observed based on measurements of real events.
15. In lieu of a formal simulation-based study, we used information on the observed frequency response of the interconnections, and insights on the technical underpinnings of frequency control to develop an approximate analytical representation of the frequency response of the Eastern Interconnection. Applying our approach along with the frequency response metrics developed earlier suggests that the Eastern Interconnection should be able to be operated reliably with the levels of wind generation output expected

in 2012, which represents approximately 1% of the total expected electricity requirements of the interconnection.

### Recommendations

1. Efforts should be accelerated now to better understand interconnection- and balancing authority-specific requirements for frequency control, especially in the Eastern Interconnection, considering among other things the frequency response metrics validated in this study.
2. Interconnections must schedule adequate primary and secondary frequency control reserves to both manage variations in net system load caused by increased levels of wind generation and withstand the sudden loss of generation, which can occur at any time.
3. The frequency control capabilities of the interconnections should be expanded, as follows:
    a. Expanded use of the existing fleet of generation (improved generator governor performance, increased operating flexibility of baseload units, faster start-up of units, etc.);
    b. Expanded use of demand response that is technically capable of providing frequency control (potentially including smart grid applications), starting with broader industry appreciation of the role of demand response in augmenting primary and secondary frequency control reserves;
    c. Expanded use of frequency control capabilities that could be provided by variable renewable generation technologies (primary frequency control, etc.); and
    d. Expanded use of advanced technologies, such as energy storage and electric vehicles.
4. Comprehensive planning and enhanced operating procedures, including training, operating tools, and monitoring systems, should be developed that explicitly consider interactions between primary and secondary frequency control reserves, and address the new source of variability that is introduced by wind generation.
5. Requirements for adequate frequency control should be evaluated in assessments of the operating requirements of the U.S. electric power system when considering new potential sources of generation and the retirement of existing generation.

### A Call to Action

The physical limits to the reliable integration of variable renewable generation are already well understood to be the transmission infrastructure required to deliver this generation to load. This study has focused on the important requirements related to interconnection frequency response that must also be addressed to ensure reliable operation.

This study has confirmed the validity of using frequency response as predictive metrics to assess the reliable operation of interconnected systems that are managing major changes in generation resources, particularly such as the integration of variable renewable generation. The concept will work however, with other changes in generation mix, and changes to existing resources such as plant retirements. Although transmission operators have conducted a number of studies to address many of the operating issues related to the integration of variable renewable generation, these studies have not focused on primary frequency control or on the interaction between reserves for primary and secondary frequency control.  At the same time, there is a separate growing industry concern regarding the declining quality of frequency control.  As the amount of variable renewable generation grows and other changes are made to the generation resource mix, it is essential to understand and address the root causes of this trend and take actions to ensure that adequate frequency control reserves are scheduled by balancing authorities.

Ultimately, the technical and institutional issues that must be addressed in integrating variable renewable generation and other types of generation depend on the unique features of and resources available within each interconnection, the ability to predict the operation of these generation resources, and the availability of new sources of frequency control such as demand response and energy storage.  Therefore, careful study, planning, and deliberate actions will be required by each interconnection to ensure the continued reliability of the U.S. electric power system.

## Executive Summary

An interconnected electric power system is a complex system that must be operated within a safe *frequency* range in order to reliably maintain the instantaneous balance between generation and load. This is accomplished by ensuring that adequate resources are available to respond to expected and unexpected imbalances and restoring frequency to its scheduled value in order to ensure uninterrupted electric service to customers. Electrical systems must be flexible enough to reliably operate under a variety of “change” scenarios. System planners and operators must understand how other parts of the system change in response to the initial change, and need tools to manage such changes to ensure reliable operation within the scheduled frequency range.

This report presents a systematic approach to identifying metrics that are useful for operating and planning a reliable system with increased amounts of variable renewable generation which builds on existing industry practices for frequency control after unexpected loss of a large amount of generation. The report introduces a set of metrics or tools for measuring the adequacy of frequency response within an interconnection. Based on the concept of the *frequency nadir*, these metrics take advantage of new information gathering and processing capabilities that system operators are developing for wide-area situational awareness. Primary frequency response is the leading metric that will be used by this report to assess the adequacy of primary frequency control reserves necessary to ensure reliable operation. It measures what is needed to arrest frequency decline (i.e., to establish a frequency nadir) at a frequency higher than the highest set point for under-frequency load shedding within an interconnection. These metrics can be used to guide the reliable operation of an interconnection under changing circumstances.

The frequency response metrics introduced here can be used not just to manage the integration of variable renewable generation but also to guide and gauge the extent and success of reliable integration of any new resource into an interconnection.[11] They can be used to map a transition path when major changes are made to existing resources such as conventional plant retirements or de-ratings.

Wind is expected to be a major new source of electricity generation to each of the interconnections in the near term, so this study tested and validated the frequency response metrics in simulations of the generation and transmission infrastructures that system operators expect to have in place in 2012. Wind generation presents challenges for the reliable operation of the electric power system, in part because the electricity generated from wind is more variable than electricity generated from conventional sources. The purpose of this report however, was not to specifically determine the theoretical amount of wind generation that can be reliably integrated into an interconnection nor of other types of generation that industry may decide to build. Rather, it presents and validates a tool that can be used to assess and plan for the operational requirements for reliable integration of variable renewable generation. In order to validate the concept, it was applied to each of the interconnections. This approach showed that the wind generation capacity projected for 2012 in the Western and Texas interconnections can be reliably integrated. If higher levels of wind generation are integrated, this tool can be used to

[11] The term variable renewable generation refers to electricity generation facilities whose energy source: 1) is renewable; 2) cannot be stored by the facility owner or operator; and 3) has variability that is beyond the control of the facility owner or operator. This includes wind and solar generation facilities and certain hydroelectric resources.

determine changes in primary and secondary frequency controls that will be required in addition to transmission identified by other studies. The tool can also be used in operating and planning the transmission system and designing markets to fully integrate and reliably operate the mix of generation and transmission resources that are deployed in the future. Further, the metrics can be used to identify the appropriate use of new technologies such as demand response and energy storage devices in achieving reliable operation.

As part of its responsibility to oversee the reliability of the nation's bulk power system, the Federal Energy Regulatory Commission (FERC) staff commissioned Lawrence Berkeley National Laboratory (LBNL) to determine if frequency response is an appropriate predictive metric to assess the level of renewable resources that can be reliably added to the power grid. [12]

FERC staff commissioned LBNL to study how a critical aspect of reliability -- the control of power system frequency during the period immediately following the sudden loss of a large conventional power plant –can be better measured to assess the adequacy of frequency control in the interconnections currently and be used to manage the reliable integration of new resources, including variable renewable generation. Specifically, the objectives of this study are:

1. To determine whether metrics for frequency response[13] could be used to assess the reliability impacts of integrating variable renewable generation;
2. If so, to use these metrics to assess the potential reliability impact of new variable renewable generation on the electric power system, by interconnection, following the sudden, instantaneous loss of large conventional power plants[14]; and
3. To identify what further work and studies are necessary to quantify and address any reliability impacts associated with the integration of variable renewable generation.

Several aspects of this scope must first be clarified in order to understand the study's methods, findings, and recommendations:

1. FERC did not ask LBNL to study the type, amount, cost or timing of transmission investments required to integrate variable renewable generation reliably because it is already understood that physically integrating increased wind generation will require significant transmission infrastructure investment. Other studies have and will continue to examine these requirements. This report complements these studies by focusing on the operational requirements necessary to ensure that whatever transmission system is in place can be operated reliably.
2. FERC asked LBNL to study frequency response, or primary frequency control. Accordingly, this study focuses on the resiliency of the power system following the sudden, instantaneous loss of large conventional power plants. Other studies have and will continue to examine requirements for managing the variability of wind generation output through secondary frequency control reserves, which occurs much more slowly

[12] The scope of this project was broadened from the original scope announced in May, 2009 as the research progressed, revealing the general applicability of frequency response metrics to analyze a broad range of changes that a complex interconnected electric system must manage to ensure reliability.

[13] Frequency response is a technical term used by the industry to describe how a power system has performed in responding to the sudden loss of generation, which is one of the most important threats to reliability.

[14] This assumes that the system is designed and operated such that a common mode transmission failure will not result in the loss of large quantities of either variable renewable or conventional generation.

than the sudden and unexpected events analyzed here. This study, however, complements these studies by introducing the additional measures that must be taken to ensure that power systems with large amounts of wind generation can withstand the sudden loss of large amounts of conventional generation.

3. FERC asked LBNL to study wind generation because it is expected to be the dominant form of variable renewable generation over the near term. The methods and metrics employed by this study can and should be applied to study the operational requirements for reliability posed by all anticipated changes to the electric power system.

**The Development of Frequency Response Performance Metrics and Rationale for their Use to Assess the Reliability Impacts of Integrating All Forms of Generation, including Variable Renewable Generation**

Reliability practices seek to ensure that, following the sudden and unplanned loss of large conventional generators, an interconnection will continue to deliver electricity to customers without interruption. Ensuring reliability in these circumstances depends on the continuous availability of a critical component of operating reserves called primary frequency control reserves. These reserves are normally provided by generating units that are on line and operating below their full generating capability. [15] Following the sudden loss of a large conventional generator, the automatic, autonomous, and immediate increase in output from these resources seeks to quickly arrest and stabilize the frequency of an interconnection, usually within 10 seconds or less. If the actions of these primary frequency control reserves are inadequate, frequency will continue to decline, and customer loads will be interrupted through the automatic actions of an extreme measure of last resort, called under-frequency load shedding. Under-frequency load shedding involves interrupting electric service to large, pre-set groups of customers; these customers will experience a blackout. Shedding large amounts of load in this manner is a drastic action (because customers' electric service is interrupted) that can have unintended consequences (because it may lead to an even wider spread blackout). [16] Operators, therefore, strive to ensure that primary frequency control reserves are always adequate to arrest frequency decline following the sudden loss of large conventional generators and prevent the triggering of under-frequency load shedding.

The reserves that are required to provide primary frequency control will depend on the size and composition of a power system, the size of the loss of generation events the power system is expected to withstand, and the set points for under-frequency load shedding, which establish the lowest acceptable frequency nadir following the sudden loss of conventional generation. The adequacy of reserves maintained to provide primary frequency control can be assessed using three metrics that measure how these reserves will perform in arresting and stabilizing frequency following the sudden loss of conventional generation.[17] The first metric, frequency nadir, is a direct measure of how close a system has come to interrupting delivery of electricity to customers. The second metric, nadir-based frequency response, relates the amount of generation

[15] See Section 2.2 for a more detailed description of primary frequency control.

[16] See Section 2.2 for a more detailed description of under-frequency load shedding.

[17] See Section 2.4 for more detailed descriptions of the frequency response metrics.

lost to the decline in frequency until arrested. The third metric, primary frequency response, measures the power actually delivered by primary frequency control actions during critical periods before and after the nadir is formed.

The usefulness of these performance metrics does not depend on the composition of generating plants within an interconnection or the size of the interconnection. They can be used to assess the capability or performance of any power system to deliver electricity uninterrupted following the sudden loss of generation. Consequently, they are appropriate metrics to use to study and plan for changes in any interconnection and to assess success in reliably integrating new resources such as variable renewable generation.

**Using Frequency Response Metrics to Guide and Gauge Success in Reliably Integrating Variable Renewable Generation**

As discussed above, the requirements for adequate primary frequency control reserves depend on: 1) the events (i.e., the amount of conventional generation that might be lost) that the interconnection is expected to withstand; 2) the frequency set points at which under-frequency load shedding is deployed within an interconnection; and 3) the efficacy of primary frequency control actions in arresting the rapid frequency decline following these events before these set points are crossed.

Increased variable renewable generation is not expected to affect the first two of these factors. The rapid ramping[18] of variable renewable generation output is not considered an event comparable to the sudden loss of large conventional generators and variable renewable generation is not expected to affect the set points for under-frequency load shedding.

We find, however, that increased variable renewable generation will have four impacts on the efficacy of primary frequency control actions and that primary frequency response metrics can be tools to plan for and manage reliable operation following the sudden loss of large conventional generators:

1. Lower system inertia.[19] If the total amount of generation on line remains the same, the system inertia of the interconnections will be lowered by increased variable renewable generation because the dominant form of variable renewable generation currently does not contribute the same inertia to the interconnection as the conventional generation it replaces. While this effect is expected to be less significant compared with the other three discussed next, lower system inertia increases the requirements for primary frequency control reserves in order to arrest frequency at the same nadir following the sudden loss of a conventional generator.

2. Displacement of primary frequency control reserves. The amount of primary frequency control reserves that are on line and available may be reduced as the conventional

[18] Variable renewable generation output can be expected to decrease each day during the morning time frame when electrical demand is increasing. The combination can produce ramps higher than what has been experienced in the past.

[19] See Section 2.2 for a description of system inertia.

generation-based sources for these reserves are displaced by variable renewable generation, which currently does not provide primary frequency control. As a result, planning and operating procedures may need to be strengthened to ensure adequate primary frequency control reserves are on line and available at all times.

3. Affect the location of primary frequency control reserves. Related to 2 above, the resulting re-dispatch of the resources (generation and demand response) that are expected to provide primary frequency control may lead to transmission bottlenecks that prevent effective delivery of primary frequency control when it is needed. As a result, planning and operating procedures must ensure that adequate primary frequency control reserves are deliverable and are therefore properly located and dispatched within the transmission system. The dispatch must ensure that the reserves can respond immediately to the sudden loss-of-generation events the interconnection is expected to withstand without overwhelming the ability of the transmission system to deliver this response.

4. Place increased requirements on the adequacy of secondary frequency control reserves. The demands placed on slower forms of frequency control, called secondary frequency control reserves, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary frequency control reserves, primary frequency control reserves (that are set-aside to respond to the sudden loss of conventional generation) will be used to make up for the shortfall. The remaining primary frequency control reserves may be inadequate to prevent operation of under-frequency load shedding following the sudden loss of a large conventional generator. As a result, planning and operating procedures must ensure that the required primary frequency control reserves are always protected (and thereby available to respond to loss-of-generation events) by ensuring adequate secondary frequency control reserves.

All four potential impacts are within the scope of responsibility of the planning and operating processes involved in assessing, forecasting, scheduling, and dispatching generation and demand response resources in order to meet system demand reliably. All four require careful study and are the focus of this report. The metrics introduced here are designed to provide a tool to guide and gauge the extent and success of these operational processes.

### The Motivation for Using Primary Frequency Response Metrics to Study the Reliability Impacts of Integrating Variable Renewable Generation

The declining quality of frequency control in the U.S. interconnections is currently a significant reliability concern. It is widely understood that the operational integration of variable renewable generation is not related to and has not been a cause or contributor to the decline observed over the past decade. System operators report that the operational issues related to renewable integration have been manageable. They also report that they do not currently view frequency-response-related reliability impacts of variable renewable generation as a significant operational concern. However, as noted previously, all are reviewing potential impacts.

Recent studies of renewable integration within the U.S. have focused on increased requirements for secondary frequency control (regulation and load following), but only to a limited extent if at all on requirements for primary frequency control. International experiences, in particular from countries with large wind penetrations, provide selected, yet important insights for the U.S. Still, those countries' interconnections and operating practices differ from those in the U.S. The academic literature has begun to document frequency response implications of the very low amounts of inertia provided by current wind generation technologies, but no studies of these impacts have been performed using validated models of U.S. interconnections.

**Dynamic Simulation Studies to Assess the Frequency-Response-based Reliability Impacts from Integration of Variable Renewable Generation**

We studied the frequency response of each of the three U.S. interconnections using the same dynamic simulation tools and system models used by the industry. These tools and models were developed to assist the industry in analyzing, among other things, the effectiveness of operating reserves in stabilizing power system frequency following the sudden loss of generation. These tools and models are used routinely by the industry to anticipate and address emerging reliability issues that they expect to face.

We preface our findings by noting that we were only able to study the generation (including wind) and transmission system that was represented in the system models developed and provided to us by industry. In addition, the tools and models available today cannot be used to predict the fourth potential impact of variable renewable generation on frequency response (the erosion of primary frequency control reserves as secondary frequency control reserves are fully deployed). Hence the findings from our simulation studies must be further prefaced with the following caveat: *"Subject to the adequacy of secondary frequency control reserves, we find the following with respect to the adequacy of primary frequency control reserves…"*

For the Western Interconnection, assuming operating reserve conditions that are representative of current practices and that are used in daily operations (which are higher than the minimum levels that are allowable under current operating procedures), our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected by 2012. The system model we studied included 9 GW of installed wind generation capacity, which based on an assumed 35% capacity factor and NERC's estimate of electricity demand in 2012 could supply approximately 3 percent of the interconnection's expected electricity requirements in 2012. We were not able to study higher levels of wind generation capacity (consistent with the amounts and locations suggested by current interconnection queues for years after 2012) because the transmission system represented in the model provided for our study could not accommodate these higher levels of wind generation capacity without additions or upgrades.

However, we also find that there could be risks to reliability under certain operating conditions involving times of minimum system load, high levels of wind generation, and with operating reserves near the minimum that is allowable under current operating procedures and standards. We note that, according to staff at the Western Electricity Coordinating Council, these operating reserve conditions are rarely observed in daily operations. Still, because these conditions are permissible under current operating procedures and standards, they are a cause for concern, which we address in our recommendations.

For the Texas Interconnection, assuming operating reserve conditions that reflect the lower range of the current operating practices, our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected in 2012. The system model we studied included 14.4 GW of installed wind generation capacity which, based on an assumed capacity factor of 35% and NERC's estimates of electricity demand in 2012 could supply approximately 10 percent of the interconnection's expected electricity requirements in 2012. Notably, the results depend on the completion of significant portions of the new transmission that has been planned through the Competitive Renewable Energy Zone process.

Our study of the Texas Interconnection also confirms the effectiveness of the interconnection's reliance on a specialized form of demand response to control frequency following the sudden loss of generation. The interconnection's "Load acting as a Resource" program provides for customers to activate controls that automatically curtail selected loads whenever low-frequency conditions are sensed on the interconnection. Our simulation studies find that this program, whose principles may also be applicable within the Western and Eastern Interconnections, is an effective complement to the primary frequency control reserves currently provided by generating units. We address expanding the supply of sources of primary frequency control reserves, including this specialized form of demand response, in our recommendations.

For the levels studied, a principal finding from our simulations of the Western and Texas Interconnection is that the rapid delivery of power via primary frequency control actions is more important than the amount of wind generation in determining the frequency nadir. The effect of increased wind generation in lowering system inertia is not significant compared to the effects of primary frequency control actions. The simulations also suggest that focused attention on the quality of primary frequency control actions, provided by generator governors and, in the Texas Interconnection, frequency-responsive demand response, can readily off-set the effects of increased wind generation on system inertia.

We were not able to conduct simulation studies of increased levels of variable renewable generation in the Eastern Interconnection. We found that, using the system model that was provided to us by industry, we could not reproduce the frequency response of the Eastern Interconnection to a recent recorded event involving the sudden loss of a large amount of generation. The simulation results predict that the frequency response of the interconnection was much more robust than the actual frequency response that has been observed based on measurements of real events. We concluded that it would not be meaningful to conduct a simulation-based study of the Eastern Interconnection with higher levels of wind generation without system models that are better calibrated to reproduce the actual performance of the interconnection.

In lieu of a formal simulation-based study, we used information on the observed frequency response of the interconnections, and insights on the technical underpinnings of frequency control to develop an approximate analytical representation of the frequency response of the Eastern Interconnection. Applying our approach along with the frequency response metrics developed in this report suggests that the Eastern Interconnection should be able to be operated reliably with the levels of wind generation output expected in 2012, which, assuming a 35%

capacity factor, represents approximately 1% of the total expected electricity requirements of the interconnection in 2012.

**The Reliability Impacts of Integrating Variable Renewable Generation on the Interaction between Primary and Secondary Frequency Control Reserves**

Variable renewable generation will affect the interaction between primary and secondary frequency control reserves. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserves than has been the case in the past because we believe this is likely to emerge as the most significant frequency-response-based impact of variable renewable generation on reliability.

This interaction has not been fully examined in prior studies of the secondary frequency control requirements associated with managing power systems with increased variable renewable generation, in part, because the focus of these studies has been on estimating overall increases in requirements for regulation and load-following on a year-round or average expected basis. As a result, the aspects of these requirements most important for ensuring adequate frequency response – namely, the potential for depletion of secondary frequency control reserves to then deplete primary frequency control reserves – during extreme (not only average or routine) circumstances has not been a focus of these studies.

Recent studies have made great strides in assessing the increased requirements for secondary frequency control reserves (i.e., increased requirements for regulation and load following). This report has not sought to improve upon these estimates although it has pointed to areas where greater clarity in future presentations of results will aid in assessing the impacts on reliability. This study has shown, however, that we cannot conduct definitive studies following the traditional approach embodied in today's dynamic simulation tools.

Deterministic studies will never replicate the inescapable role that operator discretion can, should, and, we expect, will always play in proactively deploying secondary frequency control reserves in the face of new and less familiar operating conditions involving extreme wind ramping events. Consequently, the focus should expand to include development of tools that can rapidly assess a wide range of "what if" operating scenarios and operator training using these tools, as well as to improving short-term forecasting, and providing better real-time information on the current capabilities of the resources available to provide primary and secondary frequency control. The frequency response metrics developed in Section 2 should be used to help guide these activities.

**Further Work and Studies are Required to Address the Reliability Impacts Associated With the Integration of Variable Renewable Generation and Other Generation Resource Development**

***Efforts should be accelerated now to better understand interconnection- and balancing authority-specific requirements for frequency control, especially in the Eastern Interconnection, considering among other things the frequency response metrics validated in this study***

It is widely acknowledged that the industry, especially in the Eastern Interconnection, is currently grappling with the implications of the declining quality of frequency control within the interconnection (NERC 2009d, NERC 2010a, NERC 2010b). Progress in improving our understanding of and addressing the root causes of declines in frequency response is important for protecting reliability both today and in the future as the nation's mix of generation sources changes. The potential impacts of variable renewable generation on interconnection frequency discussed in this study reinforce the need to address these issues proactively while levels of variable renewable generation are still modest. We recommend an acceleration of efforts to determine the root causes of the declining quality of frequency control, assess the risks posed for reliability, and take all actions necessary to ensure adequate frequency control is available in real time operation to ensure reliability. Improved data collection and ongoing monitoring of trends, in addition to empirically verified, calibrated system models for dynamic simulation studies, should be essential elements of these activities.

***Interconnections must schedule adequate primary and secondary frequency control reserves to both manage variations in net system load caused by increased levels of wind generation and withstand the sudden loss of generation, which can occur at any time.***

Our analytical and simulation studies have highlighted the essential roles that primary and secondary frequency control reserves play in ensuring reliability, especially the rapid and sustained provision of power from primary frequency control reserves immediately following the sudden loss of generation. Our simulations indicate that frequency control will be adequate in the Western and Texas interconnections for the generation and transmission infrastructure that system operators are expecting to be in place in 2012. Moreover, with planning and operating procedures that ensure adequate reserves for primary and secondary frequency control as well as targeted additional transmission, our simulations suggest that increased levels of variable renewable generation can be integrated reliably. Therefore, interconnections must schedule, commit, and maintain adequate primary and secondary frequency control reserves during normal operation in order to assure reliable operations after credible contingencies and to restore reserves after such contingencies.

***The frequency control capabilities of the interconnections should be expanded by increasing capabilities available within the current generation fleet and by pursuing new opportunities offered by wind generation, demand response, and energy storage.***

The economic dispatch[20] of variable renewable generation may displace generation that otherwise would have provided primary and secondary frequency control reserves. Conventional generation is currently the principal source of reserves for primary and secondary frequency control. This study has identified displacement of these sources as a potential reliability impact of increased variable renewable generation. However, there are many currently under-utilized and potential future sources of primary and secondary frequency control available in addition to the conventional generation fleet that might be displaced. Tapping these sources will facilitate reliable integration of increased amounts of variable renewable generation. These sources include:

1. Expanded use of the existing fleet of generation (improved generator governor performance, increased operating flexibility of baseload units, faster start-up of units, etc.);
2. Expanded use of demand response that is technically capable of providing frequency control (potentially including smart grid applications), starting with broader industry appreciation of the role of demand response in augmenting primary and secondary frequency control reserves;
3. Expanded use of frequency control capabilities that could be provided by variable renewable generation technologies (primary frequency control, etc.); and
4. Expanded use of advanced technologies, such as energy storage and electric vehicles.

We recommend accelerated efforts, including, for newer, less familiar sources, research, development, and especially demonstration, to increase the supply of reserves that can provide primary and secondary frequency control. This includes all necessary reinforcements and additions to the transmission system to ensure deliverability. It may also require examination of current market incentives and compensation to provide primary and secondary frequency control reserves. The frequency response metrics developed in this study can be used to guide the development of these sources in contributing to the adequacy of frequency response.

***Comprehensive planning and enhanced operating procedures, including training, operating tools, and monitoring systems, should be developed that explicitly consider interactions between primary and secondary frequency control reserves, and address the new source of variability that is introduced by wind generation.***

Increased variable renewable generation presents substantial new schedule, commitment, and dispatch challenges for power system operators. Although operators have extensive experience anticipating and managing regular diurnal ramping requirements to meet system load from conventional generation resources, integrating variable renewable generation will at times require much greater commitment and dispatch flexibility or fleet maneuverability than has previously been required. The characteristics of what is required and how it should be deployed may differ significantly and are currently less predictable than the requirements for managing familiar daily load ramps. Yet, as this study has demonstrated, it is essential that this maneuverability be provided in ways that safeguard reliability by ensuring the adequacy of

[20] Economic dispatch in the context of this report refers to the practice of dispatching generation in merit order based on increasing variable (not total) production cost.

primary and secondary frequency control reserves during operations.[21] We recommend aggressive development and adoption of comprehensive planning and enhanced operating procedures, including training and specific operating tools. These tools should anticipate minimum requirements for primary and secondary frequency control reserves, explicitly consider the interactions between these two types of reserves, and continuously monitor their adequacy during operations. Continued collection and analysis of variable renewable generation data is essential for anticipating and preparing for all operating conditions.

***Requirements for adequate frequency control should be evaluated in assessments of the operating requirements of the U.S. electric power system when considering new potential sources of generation and the retirement of existing generation***.

This study has examined a case study of the frequency-response impacts of increased variable renewable generation on the reliability of each of the three U.S. interconnections. In examining the many ways increased variable renewable generation might affect the frequency behavior of a power system following the sudden loss of generation, our study has demonstrated the importance of frequency-response-based metrics for assessing the adequacy of primary and secondary frequency control reserves. Frequency control is affected not only by the characteristics of variable renewable generators, it also depends on the characteristics of the remainder of the power system, which includes other forms of renewable generation, conventional generation, the transmission system, and the customer loads served. Thus, our study has been guided by the recognition that adequate frequency control is a fundamental requirement for reliable operation of any power system. Going forward, new technologies, economic considerations, and public policies will continue to alter the future composition of our power system (including the addition of other forms of variable renewable generation, changes in nuclear generation, retirements of generators, and changes in the electrical characteristics of customer loads, among other factors). We recommend, therefore, that reliability studies of frequency control using metrics developed here be conducted routinely on an interconnection wide basis as important and ongoing inputs to the deliberations that will guide future developments and decisions. We further recommend that these studies guide the development of the systems and procedures needed to manage these changes to the power system.

## A Call to Action

The physical limits to the reliable integration of variable renewable generation are already well understood to be the transmission infrastructure required to deliver this generation to load. This study has focused on the important requirements related to interconnection frequency response that must also be addressed to ensure reliable operation.

This study has confirmed the validity of using frequency response as predictive metrics to assess the reliable operation of interconnected systems that are managing major changes in generation resources, particularly such as the integration of variable renewable generation. The concept will work however, with other changes in generation mix, and changes to existing resources such as plant retirements. Although transmission operators have conducted a number of studies to

[21] Conventional unit scheduling, commitment and dispatch will need to take into account primary and secondary frequency control capabilities in addition to the traditional economic and security constraints.

address many of the operating issues related to the integration of variable renewable generation, these studies have not focused on primary frequency control or on the interaction between reserves for primary and secondary frequency control. At the same time, there is a separate growing industry concern regarding the declining quality of frequency control. As the amount of variable renewable generation grows and other changes are made to the generation resource mix, it is essential to understand and address the root causes of this trend and take actions to ensure that adequate frequency control reserves are scheduled by balancing authorities.

Ultimately, the technical and institutional issues that must be addressed in integrating variable renewable generation and other types of generation depend on the unique features of and resources available within each interconnection, the ability to predict the operation of these generation resources, and the availability of new sources of frequency control such as demand response and energy storage. Therefore, careful study, planning, and deliberate actions will be required by each interconnection to ensure the continued reliability of the U.S. electric power system.

## 1. Introduction

An interconnected electric power system is a complex system that must be operated within a safe *frequency* range in order to reliably maintain the instantaneous balance between generation and load. This is accomplished by ensuring that adequate resources are available to respond to expected and unexpected imbalances and restoring frequency to its scheduled value in order to ensure uninterrupted electric service to customers. Electrical systems must be flexible enough to reliably operate under a variety of "change" scenarios. System planners and operators must understand how other parts of the system change in response to the initial change, and need tools to manage such changes to ensure reliable operation within the scheduled frequency range.

This report presents a systematic approach to identifying metrics that are useful for operating and planning a reliable system with increased amounts of variable renewable generation which builds on existing industry practices for frequency control after unexpected loss of a large amount of generation. The report introduces a set of metrics or tools for measuring the adequacy of frequency response within an interconnection. Based on the concept of the *frequency nadir*, these metrics take advantage of new information gathering and processing capabilities that system operators are developing for wide-area situational awareness. Primary frequency response is the leading metric that will be used by this report to assess the adequacy of primary frequency control reserves necessary to ensure reliable operation. It measures what is needed to arrest frequency decline (i.e., to establish a frequency nadir) at a frequency higher than the highest set point for under-frequency load shedding within an interconnection. These metrics can be used to guide the reliable operation of an interconnection under changing circumstances.

The frequency response metrics introduced here can be used not just to manage the integration of variable renewable generation but also to guide and gauge the extent and success of reliable integration of any new resource into an interconnection.[22] They can be used to map a transition path when major changes are made to existing resources such as conventional plant retirements or de-ratings.

Wind is expected to be a major new source of electricity generation to each of the interconnections in the near term, so this study tested and validated the frequency response metrics in simulations of the generation and transmission infrastructures that system operators expect to have in place in 2012. Wind generation presents challenges for the reliable operation of the electric power system, in part because the electricity generated from wind is more variable than electricity generated from conventional sources. The purpose of this study however, was not to specifically determine the theoretical amount of wind generation that can be reliably integrated into an interconnection nor of other types of generation that industry may decide to build. Rather, it presents and validates a tool that can be used to assess and plan for the operational requirements for reliable integration of variable renewable generation. In order to validate the concept, it was applied to each of the interconnections. This approach showed that the wind generation capacity projected for 2012 in the Western and Texas interconnections can be reliably integrated. If higher levels of wind generation are integrated, this tool can be used to

[22] The term variable renewable generation refers to electricity generation facilities whose energy source: 1) is renewable; 2) cannot be stored by the facility owner or operator; and 3) has variability that is beyond the control of the facility owner or operator. This includes wind and solar generation facilities and certain hydroelectric resources.

determine changes in primary and secondary frequency controls that will be required in addition to transmission identified by other studies. The tool can also be used in operating and planning the transmission system and designing markets to fully integrate and reliably operate the mix of generation and transmission resources that are deployed in the future. Further, the metrics can be used to identify the appropriate use of new technologies such as demand response and energy storage devices in achieving reliable operation.

As part of its responsibility to oversee the reliability of the nation's bulk power system, the Federal Energy Regulatory Commission (FERC) staff commissioned Lawrence Berkeley National Laboratory (LBNL) to determine if frequency response is an appropriate predictive metric to assess the level of renewable resources that can be reliably added to the power grid. [23]

FERC staff commissioned LBNL to study how a critical aspect of reliability -- the control of power system frequency during the period immediately following the sudden loss of a large conventional power plant –can be better measured to assess the adequacy of frequency control in the interconnections currently and be used to manage the reliable integration of new resources, including variable renewable generation. Specifically, the objectives of this study are:

1. To determine whether metrics for frequency response[24] could be used to assess the reliability impacts of integrating variable renewable generation;
2. If so, to use these metrics to assess the potential reliability impact of new variable renewable generation on the electric power system, by interconnection, following the sudden, instantaneous loss of large conventional power plants; and
3. To identify what further work and studies are necessary to quantify and address any reliability impacts associated with the integration of variable renewable generation.

Several aspects of this scope must first be clarified in order to understand the study's methods, findings, and recommendations:

1. FERC did not ask LBNL to study the type, amount, cost or timing of transmission investments required to integrate variable renewable generation reliably because it is already understood that physically integrating increased wind generation will require significant transmission infrastructure investment. Other studies have and will continue to examine these requirements. This study complements these studies by focusing on the operational requirements necessary to ensure that whatever transmission system is in place can be operated reliably.
2. FERC asked LBNL to study frequency response, or primary frequency control. Accordingly, this study focuses on the resiliency of the power system following the sudden, instantaneous loss of large conventional power plants. Other studies have and will continue to examine requirements for managing the variability of wind generation output through secondary frequency control reserves, which occurs much more slowly than the sudden and unexpected events analyzed here. This study, however,

[23] The scope of this project was broadened from the original scope announced in May, 2009 as the research progressed, revealing the general applicability of frequency response metrics to analyze a broad range of changes that a complex interconnected electric system must manage to ensure reliability.

[24] Frequency response is a technical term used by the industry to describe how a power system has performed in responding to the sudden loss of generation, which is one of the most important threats to reliability.

complements these studies by introducing the additional measures that must be taken to ensure that power systems with large amounts of wind generation can withstand the sudden loss of large amounts of conventional generation.

3. FERC asked LBNL to study wind generation because it is expected to be the dominant form of variable renewable generation over the near term. The methods and metrics employed by this study can and should be applied to study the operational requirements for reliability posed by all anticipated changes to the electric power system.

LBNL reviewed both domestic and international experiences with integration of variable renewable generation and conducted a series of analytical investigations of the physical principles involved in and current industry practices for managing or controlling power system frequency. These investigations focused on how control of power system frequency could be affected by increased amounts of wind generation. The investigations culminated in dynamic simulation studies of the frequency response of each of the three U.S. interconnections, all of which are expecting increased amounts of wind generation.[25] The simulations used system models developed and provided by industry. This is one of the first studies of the three U.S. interconnections to consider the frequency-response-related reliability impacts of variable renewable generation on an interconnection-wide basis using commercial-grade analysis tools and industry-developed system models.

This report is organized in six sections following this introduction:

Section 2 defines and provides a rationale for the use of frequency response metrics to assess the reliability impacts of integrating all forms of generation, including variable renewable generation. The section begins with a non-technical overview of power system frequency control concepts, processes, and terminology. The overview describes the resources on which power system operators rely to control frequency and explains how these resources are deployed during normal operations and following sudden large imbalances between generation and load, such as those caused by the unexpected loss of conventional generation. The section then defines and explains the usefulness of three metrics for assessing the performance of and requirements for primary frequency control, which is the critical resource required to ensure reliability following these sudden large imbalances. The remainder of this report refers to these concepts and metrics to assess the potential reliability impacts of new variable renewable generation on a power system’s ability to respond following the sudden, instantaneous loss of large conventional power plants.

Section 3 describes how the frequency response metrics developed for this study can be used to guide and gauge success in reliably integrating variable renewable generation. It first reviews the factors that determine the adequacy of primary frequency control and clarifies that two of these factors, the events the interconnection is expected to withstand and the set points for under-frequency load shedding, will not be affected by integrating variable renewable generation. Focusing on the third factor, the requirements for adequate primary frequency control, it then identifies the four ways that system reliability might be affected by variable renewable

[25] The U.S. power system consists of three interconnections, called the Western, Eastern, and Texas Interconnections. There are limited, asynchronous inter-ties between the interconnections, so each operates separately from the other two.

generation and discusses how each can be studied using frequency response metrics. Each of the interconnections anticipates integration of new renewable generation resources, and in particular, wind generators are the primary resources expected to be integrated in the near term.

Section 4 summarizes background research conducted on frequency control and operational integration of variable renewable generation (mainly wind) in the U.S. and internationally. The topics addressed include: the declining quality of frequency control of the U.S. interconnections, industry experiences with and perspectives on the integration of variable renewable generation, recent industry studies of the impacts of wind generation integration on the operation of the power system, international experiences with integrating wind generation, and recent studies of the impacts of wind integration on frequency control.

Section 5 presents findings on potential frequency-response-related impacts of increased variable renewable wind generation on the three U.S. Interconnections by 2012. The assessment is based on analysis conducted using commercially available, production-grade dynamic simulation tools and industry-developed system models, which include the amount of wind generation capacity the planners in each interconnection expect in 2012. This section first clarifies that the system models were used "as provided." The models are used to illustrate how the frequency response metrics developed in this study can be used to guide and assess the reliable integration of variable renewable generation. This section next introduces elements of the study that were common to all three interconnections. Finally, it presents findings specific to each interconnection.

Section 6 describes how variable renewable generation affects the interaction between primary and secondary frequency control reserves. Study of this interaction is affected by several factors, including, the absence of commercially available simulation tools that can realistically model the interactions between these two types of reserves (which ranges over time frames of several seconds to tens of minutes), the limited and short historical records available on extreme wind ramping events and the inescapable role of human judgment in managing the resources that are required for primary and secondary frequency control during operations. These considerations represent important caveats for the initial findings presented in Section 5. Throughout these discussions, we use the frequency response metrics developed in Section 2 and as explained in Section 3 to guide future efforts to better understand and identify actions to address these impacts.

Section 7 presents recommendations for further work and studies that are required now so that appropriate operating procedures can be put in place in the near future to ensure reliability as variable renewable generation increases and as other changes to the generation mix are considered. It is imperative that we pursue these activities pro-actively to achieve the twin goals of electricity reliability and increased resource diversity and security.

The report is accompanied by five technical reports, published separately, that were prepared in support of this project.

Undrill, J.M. 2010. *Power and Frequency Control as it Relates to Wind-Powered Generation*. LBNL-4143E. Berkeley: Lawrence Berkeley National Laboratory. December.

Martinez, C. S. Xue, and M. Martinez. 2010. *Review of the Recent Frequency Performance of the Eastern, Western and ERCOT Interconnections*. LBNL-4144E. Berkeley: Lawrence Berkeley National Laboratory. December.

Illian, H.F. 2010. *Frequency Control Performance Measurement and Requirements*. LBNL-4145E. Berkeley: Lawrence Berkeley National Laboratory. December.

Mackin, P., R. Daschmans, B. Williams, B. Haney, R. Hunt, and J. Ellis. 2010. *Dynamic Simulations Studies of the Frequency Response of the Three U.S. Interconnections with Increased Wind Generation*. LBNL-4146E. Berkeley: Lawrence Berkeley National Laboratory. December.

Coughlin, K.C. and J.H. Eto. 2010. *Analysis of Wind Power and Load Data at Multiple Time Scales*. LBNL-4147E. Berkeley: Lawrence Berkeley National Laboratory. December.

# 2. The Development of Frequency Response Performance Metrics and Rationale for their Use to Assess the Reliability Impacts of Integrating All Forms of Generation, including Variable Renewable Generation

This section defines and provides a rationale for the use of frequency response metrics to assess the reliability impacts of integrating all forms of generation, including variable renewable generation. The section begins with a non-technical overview of power system frequency control concepts, processes, and terminology. The overview describes the resources on which power system operators rely to control frequency and explains how these resources are deployed during normal operations and following sudden large imbalances between generation and load, such as those caused by the unexpected loss of conventional generation. The section then defines and explains the usefulness of three metrics for assessing the performance of and requirements for primary frequency control, which is the critical resource required to ensure reliability following these sudden large imbalances. The remainder of this report refers to these concepts and metrics to assess the potential reliability impacts of new variable renewable generation on a power system's ability to respond following the sudden, instantaneous loss of large conventional power plants.

The information in this section draws upon textbook references and two recent technical reports, one of which was prepared specifically for this project (Kirchmeyer 1959, Cohn 1971, NERC 2009a, Undrill 2010). Throughout this section, technical terms that are defined in the glossary provided at the end of this report are denoted in *italics* when they are first introduced.

## 2.1 System Frequency Reflects the Balance Between Generation and Load

The instantaneous balance between generation and load within an interconnected electric power system is directly reflected in the *frequency* of the interconnection. Reliable operation of a power system depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which, in North America, is normally 60 cycles per second or 60 Hertz (Hz). Failure to maintain frequency within these boundaries can disrupt the operation of customers' equipment, initiate disconnection of power plant equipment (to prevent them from being damaged), and lead to wide-spread blackouts.

Figure 2-1 illustrates how the relationship between generation and load determines the frequency of an electric power system using the analogy of water level within a container. If generation and load are exactly in balance (water inflow and outflow are equal), frequency is stable at 60 Hz. If generation begins to exceed load (inflow begins to exceed outflow), frequency will rise above 60 Hz. If load exceeds generation (outflow exceeds inflow) frequency will fall below 60 Hz. If, in this last example, generation is not increased (to match the increase in outflow), then frequency (water level) will fall until the power system collapses (the water in the container is depleted).

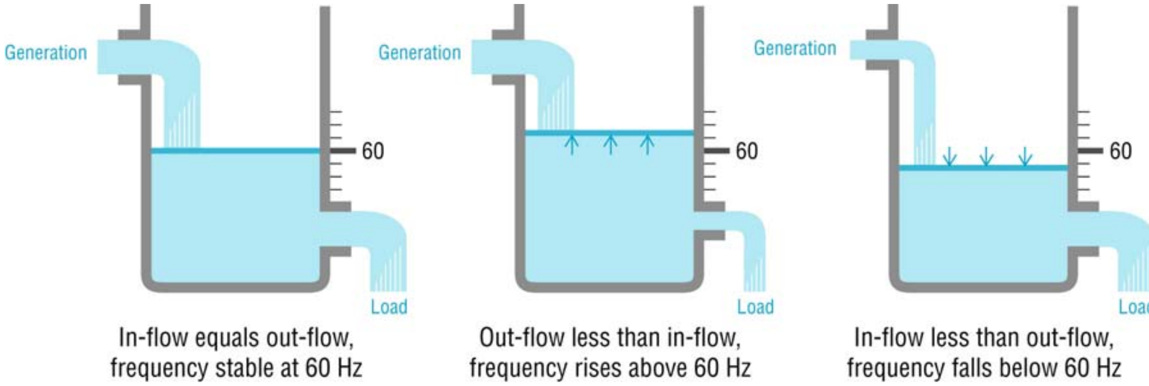


**Figure 2-1. The Concept of Power System Frequency Explained Using the Analogy of Water Level in a Container**

Maintaining frequency at a scheduled value is challenging because load varies continuously following well-understood patterns and sometimes unplanned events such as the sudden loss of generation will abruptly alter the balance between load and generation. Both cause frequency to deviate from its scheduled value.

Power system operators are responsible for ensuring that adequate resources are available to respond to imbalances and restore frequency to its scheduled value, both when they are expected and especially when they are large and unexpected. That is, the goal of power system frequency control is to maintain frequency within safe boundaries around the scheduled value at all times (in order to ensure uninterrupted electric service to customers).

## 2.2 Power System Frequency is Managed by Resources that Provide Primary and Secondary Frequency Control

Power system operators manage or control frequency mainly through adjustments to the output of generators;[26] the goal of these adjustments is to restore the balance between generation and load. When frequency is above the scheduled value, they rely on generators to decrease their output. When frequency is below the scheduled value, they rely on generators to increase their output. (The generator's actions are often referred to as "opposing [or reversing] the change in frequency".)

Generation resources are capable of taking two types of actions to control (i.e., to oppose changes in) frequency: these two types of actions are known as primary and secondary frequency control. The distinctions between the two types of actions are important because ensuring reliability depends on having the proper amounts of each form of control. The proper amounts, in turn, depend both on the variability of load during periods of normal operations and on the

[26] Specialized forms of demand response can be and in some instances are relied on for frequency control. Currently, demand response is not fully developed nor widely used as resource for frequency control. Accordingly, this discussion will focus on the dominant role of generation today for primary and secondary frequency control. However, the concepts and metric discussed are analogous when the frequency control is provided by demand response. Section 7 contains recommendations for expanding the supply of resources capable of providing frequency control, including demand response.

size of the abrupt imbalances caused by the sudden loss of conventional generation (or load), which the power system is expected to withstand.

*Primary frequency control* involves the autonomous, automatic, and rapid action (i.e., within seconds) of a generator to change its output to oppose large changes in frequency. Primary frequency control actions are especially important during the period following the sudden loss of generation because the actions required to prevent the interruption of electric service to customers must be initiated immediately (i.e., within seconds).[27] To be able to provide this response, the resources that are to provide primary frequency control must be on line and dispatched (e.g., below their maximum output) so that they are capable of increasing their output immediately. The term *head room* is sometimes used to describe the difference between the current operating point of a generator and its maximum operating capability. The primary frequency control provided by an individual generator is commonly known as *frequency response (equipment).*

Primary frequency control actions include *governor response* from generators and, more recently, *frequency-responsive demand response*. Historically, virtually all generators were relied upon to provide governor response.[28] Today, the situation has changed. Some generators, including all current nuclear generators, most wind turbines in North America, as well as many new natural gas turbines do not provide governor response. Other generators, which may be capable of providing governor response, are sometimes operated in ways that prevent them from providing that response. For example, a generator operated at its maximum capability cannot provide upward primary frequency control because it has no head room. Finally, some generators have additional controls (discussed next) that override the sustained delivery of governor response.

*Secondary frequency control* involves slower, centrally (i.e., externally) directed actions that affect frequency more slowly than primary control (i.e., in tens of seconds to minutes). Secondary frequency control actions can be initiated automatically or in response to manual dispatch commands. *Automatic generation control* (AGC) is an automatic form of secondary frequency control that is used continuously to oppose small deviations in system frequency around the scheduled value. Manual dispatch commands, which take longer to implement, are used to follow longer variations or trends in load, such as the morning ramp-up and the late evening drop-off of load through an operating day.

Secondary frequency control is only one objective of the externally directed control of a generator's output. In this case, the objective is system wide: Manage system frequency toward a scheduled value. Sometimes, generators are also directed to meet local objectives, such as

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[27] As discussed later in this Section, in order to preserve this fast-acting capability for use only during emergencies (e.g., the sudden loss of conventional generation), primary frequency control is not allowed to act until the deviation in system frequency exceeds a threshold called a dead-band.

[28] Governor response is expressed as a percentage change in power output for a given percentage change in frequency. A typical governor response setting of 5 percent means that a 5 percent decline in frequency would lead to a 100 percent increase in power output from a generator. For example, with a setting of 5 percent, a decline in frequency of 0.3 Hz (which is 0.5 percent of 60 Hz) would lead to an increase in power output of 10 percent (provided the generator was operating at 90 percent or less of its maximum output at the time of the frequency decline).

maintaining output at a constant, contracted level. The controls that effect these locally oriented actions are referred to generically as *plant secondary controls.* It is important to recognize that local objectives can conflict with and will sometimes override system-wide objectives. For example, when plant secondary control actions override (i.e., withdraw) primary frequency control actions, the effect may be detrimental to the stabilization of system frequency following the sudden loss of generation (or load).

We turn next to a description of how the two forms of frequency control operate together to manage system frequency, during periods of normal operation and following a large imbalance caused by the sudden loss of large conventional generation. See Figure 2-2.

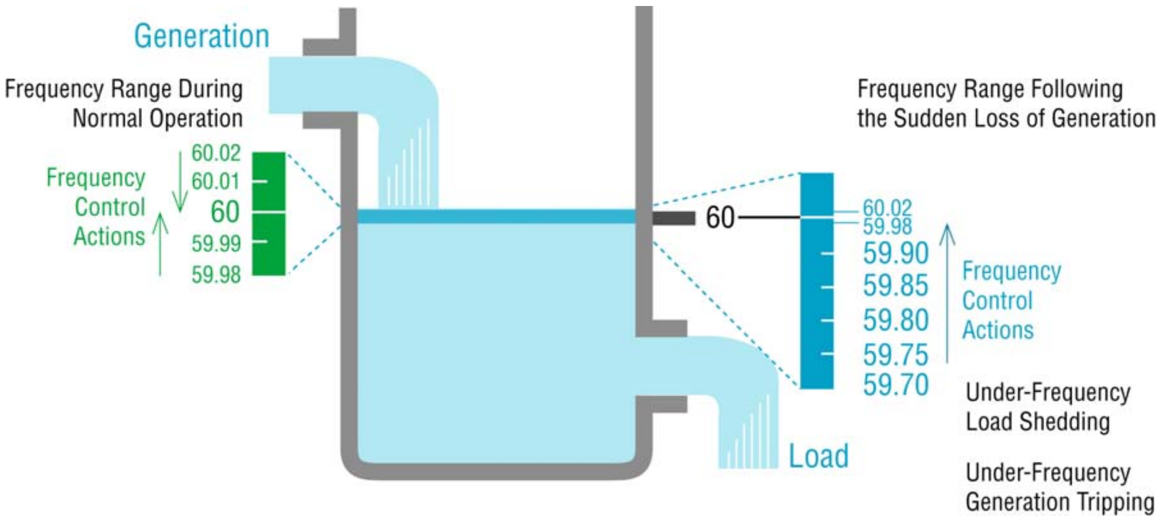


**Figure 2-2. Ranges of Power System Frequency During Normal Operations and Following the Sudden Loss of Generation**

Under normal conditions, power system operators, aided by automatic controls such as AGC, adjust the output from generation resources on a more or less continuous basis to maintain frequency within narrow boundaries around the scheduled value.[29] These efforts are planned and organized around load variability over roughly two different time scales.

The largest variations in load take place in a daily cycle; mature day-ahead and hour-ahead load forecasting play an important role in the scheduling and ramping up and down of generation resources in anticipation of the diurnal rise and fall of load. *Load following* is sometimes used to describe the coordination of generation output to follow these trends.

Smaller variations in load take place rapidly, in a matter of seconds or minutes, and continuously throughout the day, resulting in near-instantaneous deviations from the scheduled frequency value. Depending on the magnitude and speed of these deviations, secondary (and, sometimes,

[29] As discussed in Section 3, this report does not focus in detail on the deliverability of the replacement generation. Deliverability, however, is an essential requirement and cannot be overlooked. New resources may likely require not just interconnection facilities, but other network reinforcements to ensure the deliverability of primary and secondary frequency control.

primary) frequency control actions take place automatically, and continuously adjust the output from generators to compensate. This form of generation control is known as *regulation*. Secondary frequency control actions externally directed through AGC are the principal sources of regulation under normal operations. When secondary frequency control actions alone are insufficient to control frequency within pre-set limits (for example, in response to a large and rapid change in system load), frequency deviation will exceed the dead-band setting and primary frequency control reserves will then be engaged automatically to supplement secondary frequency control actions. We will discuss the interaction of secondary and primary frequency controls in more detail below.

Imbalances caused by the loss of large conventional generators are a special concern because they are sudden and unexpected. The effect of the loss of a large generating unit is felt nearly instantaneously throughout an interconnection as an immediate decline in system frequency. Power system operators hold primary and secondary frequency control resources in reserve to respond to these events. As discussed previously, primary frequency control actions provide increased power quickly to make up for the lost generation that initiated the frequency decline.[30] The objective is to rapidly restore balance between generation and load and thereby arrest the decline in frequency.[31]

If, however, primary frequency control actions are unable to arrest the decline in frequency, an extreme measure to arrest frequency decline, called *under-frequency load-shedding,* will be initiated automatically. Under-frequency load shedding disconnects large, pre-set groups of customers at predetermined frequency set points.[32]

Under-frequency load shedding is a blunt and drastic form of emergency frequency control.[33] It is intended to prevent damage to generators during the extreme imbalances in frequency that result when the integrity of the interconnected power system has been so severely compromised that portions of the system are operating as electrical "islands" distinct from one another.[34] In

[30] Frequency-responsive demand resources, if available, would take load off the system nearly instantly in support of this objective.

[31] Portions of the load served also respond automatically to changes in system frequency. This is called *load damping*. Load damping depends on the composition of loads that are on line at the time of an imbalance. The contribution of load damping to opposing changes in frequency is small compared to the contributions of primary and secondary frequency control. In addition, load damping cannot be controlled in the same way that power system operators manage the dispatch of resources that provide primary and secondary frequency control, so it is not treated further in this discussion.

[32] Under-frequency load shedding is distinct from other, less drastic forms of load shedding that involve fewer customers and that serve more localized reliability objectives. It is also distinct from voluntary demand response.

[33] Governor actions are comparatively slower than the sudden interruption of electric service to large, pre-specified groups of customers through under-frequency load shedding, which involves an immediate step change in the balance between load and generation akin to (but acting in the opposite direction of) the sudden loss of generation. In addition, governor actions are self-limiting because they inject (or withdraw) power to oppose changes in frequency only to the extent frequency has deviated from the scheduled value. Loads disconnected through under-frequency load shedding must be reconnected through specialized, operator-directed procedures.

[34] See, for example, the description of under-frequency load shedding contained in the 2003 Blackout Report: "…automatic under-frequency load-shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow

these situations, the purpose of under-frequency load shedding is to restore the balance between load and generation (by removing load) before frequency declines even further to a point at which generators disconnect automatically (in order to prevent being damaged), because once generators disconnect, the imbalance will be even larger and a larger blackout is likely to ensue.

Under-frequency load shedding can also have unintended consequences. For example, if the amount of load dropped by under-frequency load shedding is greater than the amount of generation that was lost, frequency will quickly rise and exceed the scheduled value. When this happens, other generators may disconnect themselves either automatically to protect themselves or for other reasons because frequency is now too high. Frequency will then start to decline again and an even larger blackout may ensue. See Text Box.

Therefore, it is important to recognize that under-frequency load shedding is an emergency operating measure that is to be avoided in routine operations. It is expected to be held in reserve as a safety net for use only when there are no alternatives left to arrest rapidly declining frequency.

Indeed, the principal purpose served by primary frequency control is to avoid deliberately interrupting customer loads through under-frequency load-shedding schemes. In other words, primary frequency control actions are expected to be the principal means the power system relies on to arrest rapid decline in frequency following the sudden loss of large conventional generators.

Ensuring adequate primary frequency control is a routine operating measure to ensure reliability because the sudden loss of a generator within an interconnection is not predictable, but occurs with some regularity depending on the size of (and hence number of generators within an) interconnection. In the very large Eastern Interconnection, events are recorded almost daily. In the much smaller Texas Interconnection, events are recorded on average about once every week. The very largest events, which pose the greatest threats to reliability, however, are rarely recorded more than once or twice per year.

Reliability practices seek to ensure that, following sudden, unexpected imbalances, such as the loss of large conventional generators, an interconnection will continue to deliver electricity to all customers without interruption. Power system operations planners conduct extensive studies to assess whether primary frequency control reserves are capable of arresting frequency before under-frequency load shedding would be initiated following a variety of potential imbalances. In other words, the criteria for adequacy of primary control reserves is whether or not the reserves ensure continued delivery of electricity following these events. As we shall discuss, this determination depends on the characteristics of the interconnection, the imbalance events the interconnection is expected to withstand, and the set points or triggering frequency for under-frequency load shedding.

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frequency to stabilize within the island." (U.S.-Canada Power System Outage Task Force. 2004). See, also, the preamble for Reliability Standard PRC-007-0, "Assuring Consistency with Regional UFLS Program Requirements," which states, as its purpose: "Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program." (NERC. 2009b)

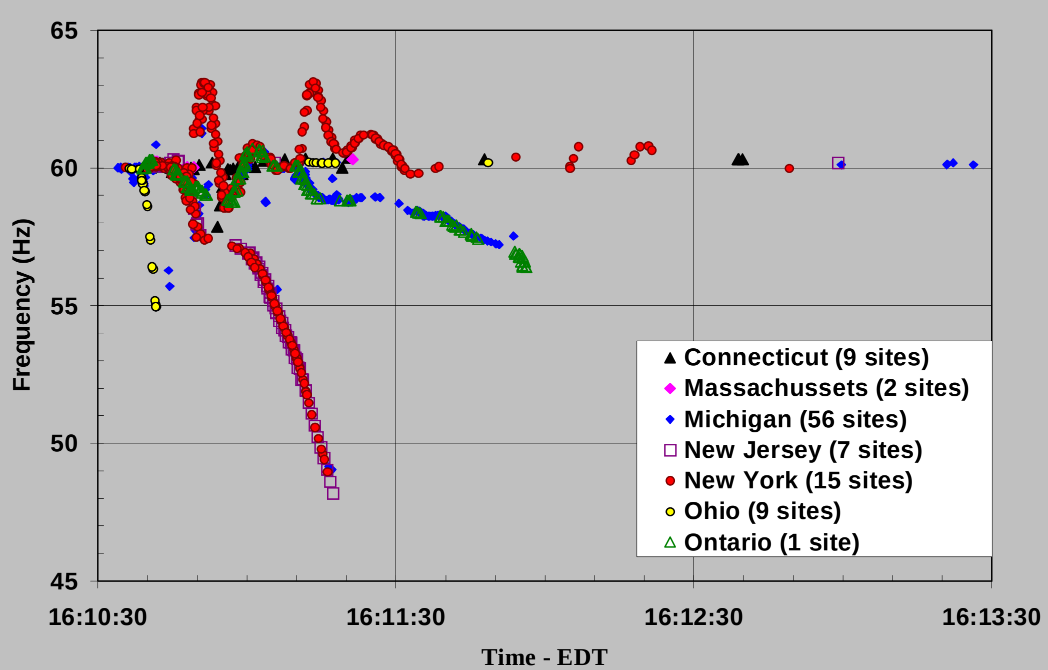
**August 14, 2003 US-Canada Blackout**

The August 14, 2003 blackout was not initiated by problems caused by system frequency. However, as a result of the initiating events, the Northeastern portion of the Eastern Interconnection broke itself into a number of electrically independent "islands."

"Once the northeast became isolated, it lost more and more generation relative to load as more and more power plants tripped off line to protect themselves from the growing disturbance. The severe swings in frequency and voltage in the area caused numerous lines to trip, so the isolated area broke further into smaller islands. The load/generation mismatch also affected voltages and frequency within these smaller areas, causing further generator trips and automatic under-frequency load-shedding, leading to blackout in most of these areas.

The figure below shows frequency data collected by the distribution-level monitors of Softswitching Technologies, Inc. (a commercial power quality company serving industrial customers) for the area affected by the blackout. The data reveal at least five separate electrical islands in the Northeast as the cascade progressed. The two paths of red diamonds on the frequency scale reflect the Albany area island (upper path) versus the New York City island, which declined and blacked out much earlier."

Source: U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. April.




When a large conventional generator is lost unexpectedly (i.e., the power system experiences a loss-of-generation event), system load immediately exceeds generation, and frequency begins to decline immediately. See Figure 2-3. The rate (or slope) of this initial decline in frequency is determined by two factors: 1) the *inertia* of the power system at the time the generator is lost, and 2) the amount of power produced by the generator at the time it is lost. Inertia is a technical term that describes the ability of the power system to resist changes in frequency. It is measured in MW-seconds. Inertia is an inherent property or characteristic of each generator and element of load. The inertia of a power system is determined by the combined inertias of all of the connected generators and loads that are directly coupled to the power system at any given time.

The relationship between system inertia and amount of generation lost is easiest to understand by re-expressing each quantity as a percentage of a "normalizing" factor that is related to the total size of the power system as follows: 1) normalized system inertia is total system inertia divided by total connected generation; and 2) normalized generation loss is the amount of generation lost divided by total generation. To a first approximation, the slope or initial rate of decline of frequency is determined by the normalized generation lost divided by twice the normalized system inertia.[35]

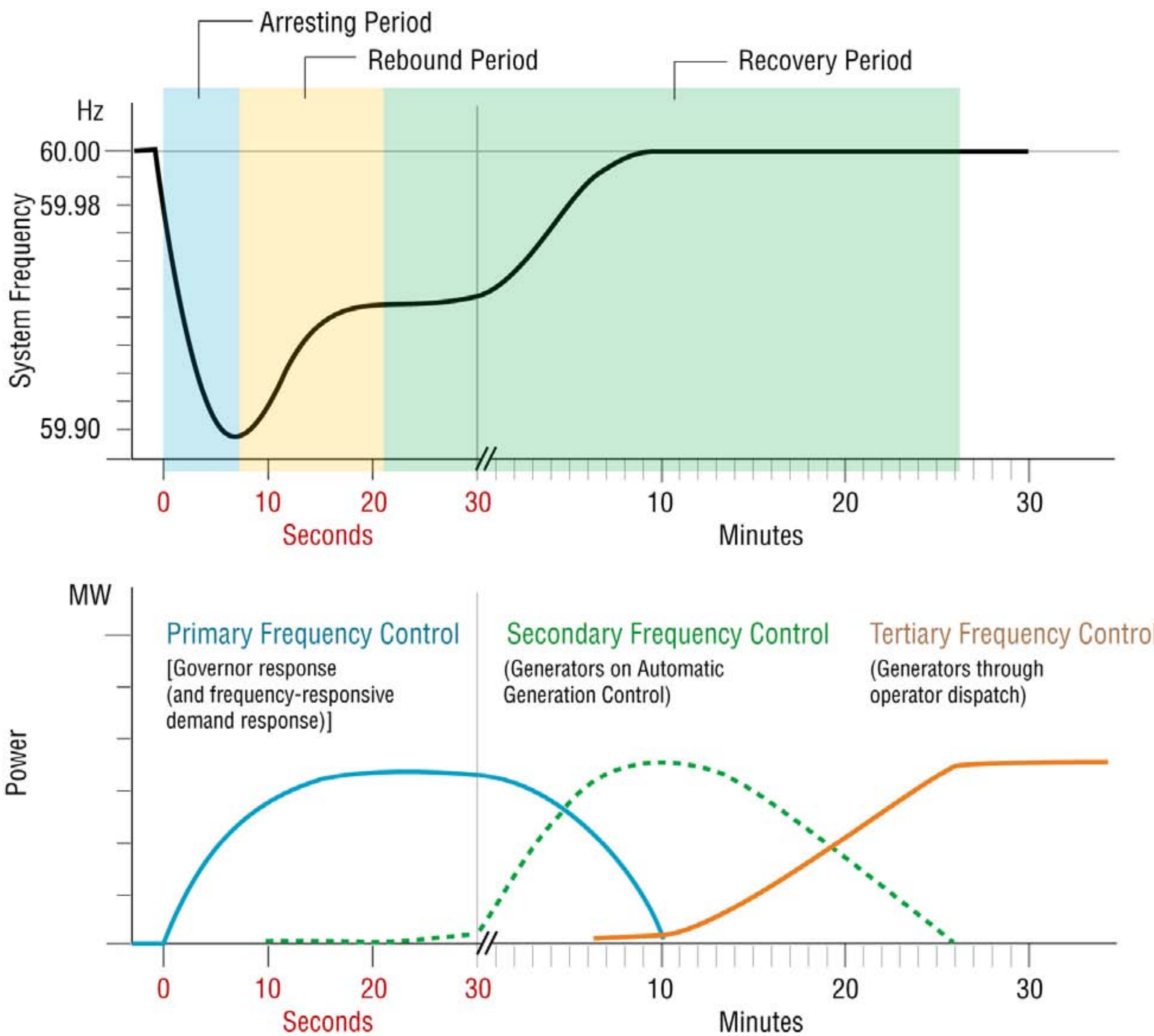
The interpretation of this relationship is as follows: Holding the amount of generation lost fixed (i.e., same normalized amount of lost generation), frequency will fall faster in a power system that has lower normalized system inertia than it will in a power system that has higher normalized system inertia. A power system with higher normalized system inertia is more resistant to the change in frequency caused by the loss of a given amount of generation.

Holding normalized system inertia fixed, frequency will fall faster when more generation is lost (higher normalized generation loss) than it will when less generation is lost (lower normalized generation lost). For any power system, loss of a greater percentage of total generation causes frequency to fall faster than loss of a smaller percentage of total generation.

These relationships are critical to understanding the requirements (discussed next) for arresting frequency prior to triggering under-frequency load shedding. As will be discussed in Section 3 and 5, the normalized system inertias of the Eastern, Western, and Texas Interconnections are relatively close in value to one another (roughly, 4 to 5 seconds). This is not a surprise. Despite vast differences in the total number of generators within each interconnection, the composition of generators is similar.[36] On the other hand, due to the great differences in the sizes of the interconnections, the loss of a given amount of generation represents very different percentages of total generation within each interconnection. To illustrate, loss of 2 GW of generation at the time of peak demands in the Texas Interconnection (about 60 GW) represents slightly more than 3% of total generation. Loss of 2 GW of generation at the time of peak demand in the Eastern Interconnection (about 600 GW) represents slightly more than 0.3% of total generation. Therefore, at the time of peak demand, loss of 2 GW of generation will cause frequency to fall much faster in the Texas Interconnection than it will in the Eastern Interconnection. In addition, to arrest for a specific percentage generation loss and stabilize frequency at a given frequency nadir (above the highest set point for under-frequency load shedding), a power system with lower inertia will require faster provision of power from primary frequency control actions than will a system with higher inertia.

[35] For the purpose of this illustrative discussion, we ignore the effects of *load-damping*, which refers to comparatively small changes in the load that are caused by the change in system frequency. See Footnote 31.

[36] The aspects of generators that determine their contribution to system inertia depends on the types of turbines used to generate electricity (e.g., steam turbines, combustion turbines, hydro-electric turbines, etc.), and not on the types of fuels consumed (e.g., nuclear, coal, natural gas, and fuel oil can all be used to run a steam turbine). See Undrill (2010) for a more information on the inertia contributed by different turbine types.




Note: Load-damping is not shown on this figure. See Footnote 31.

**Figure 2-3. The Sequential Actions of Primary, Secondary, and Tertiary Frequency Controls Following the Sudden Loss of Generation and Their Impacts on System Frequency**

If no corrective actions are taken after the sudden loss of a large conventional generator, system frequency will decline until the power system collapses. The lower portion of Figure 2-3 illustrates the frequency controls used to prevent such a collapse. Primary frequency control actions (and, in extreme circumstances, under-frequency load shedding) are the only frequency control actions that can oppose the free-fall of frequency fast enough to prevent the entire power system from going black. Following the sudden loss of generation, the automatic, autonomous, and immediate increase in power output by resources providing primary frequency control actions seeks to quickly arrest and stabilize the frequency of the interconnection, usually within 20 seconds or less. This is labeled the “arresting period” in Figure 2-3. Secondary frequency control actions, because they are externally directed, are too slow to contribute to the arrest and stabilization of frequency in the short time available. Thus, ensuring reliability (including avoiding under-frequency load shedding) depends on the availability of adequate primary frequency control reserves.

It is important to recognize that frequency decline is arrested only by the portion of primary frequency control actions that is actually delivered, usually within the initial seconds following the sudden loss of generation. The point at which frequency decline is arrested is called the *frequency nadir*. Once frequency decline has been arrested, continued delivery of primary frequency control actions, if available, will stabilize frequency at a higher value but still lower than the frequency prior to the loss of generation. This is labeled the "rebound" period in Figure 2-3. The point at which frequency is stabilized is called the *settling frequency*.

After the actions of primary frequency control reserves to arrest and stabilize frequency, the initial goal of secondary frequency control reserves is to return frequency to the scheduled value through the actions of AGC. Secondary frequency control actions do not contribute materially to the restoration of frequency until 30 seconds or more following the loss of generation and can take anywhere from about 5 to 15 minutes (or more) to restore frequency to the scheduled value. This is labeled the "recovery" period in Figure 2.3. Consequently, sustained delivery of primary frequency control actions after frequency has been stabilized is important during the recovery period.

*Tertiary frequency control* refers to centrally coordinated actions (i.e., it is a form of what we have called secondary frequency control) that operate on an even longer time scale (i.e., minutes to tens of minutes) than primary frequency control and secondary frequency control provided through AGC. The goal of these actions is to restore the reserves that have been used to provide primary and secondary frequency control following a loss-of-generation event, in order to re-position the power system so that it can respond to a subsequent loss-of-generation event. Tertiary frequency control actions entail coordinated changes in generating unit loading and commitment (e.g., dispatching one generator down to restore its reserve capability while simultaneously dispatching another generator up to replace the power provided by the first generator, all the while maintaining system frequency). The deployment of tertiary frequency control represents the final stage of the recovery period indicated on Figure 2.3.

## 2.3 The Relationship between Operating Reserves and Primary and Secondary Frequency Control

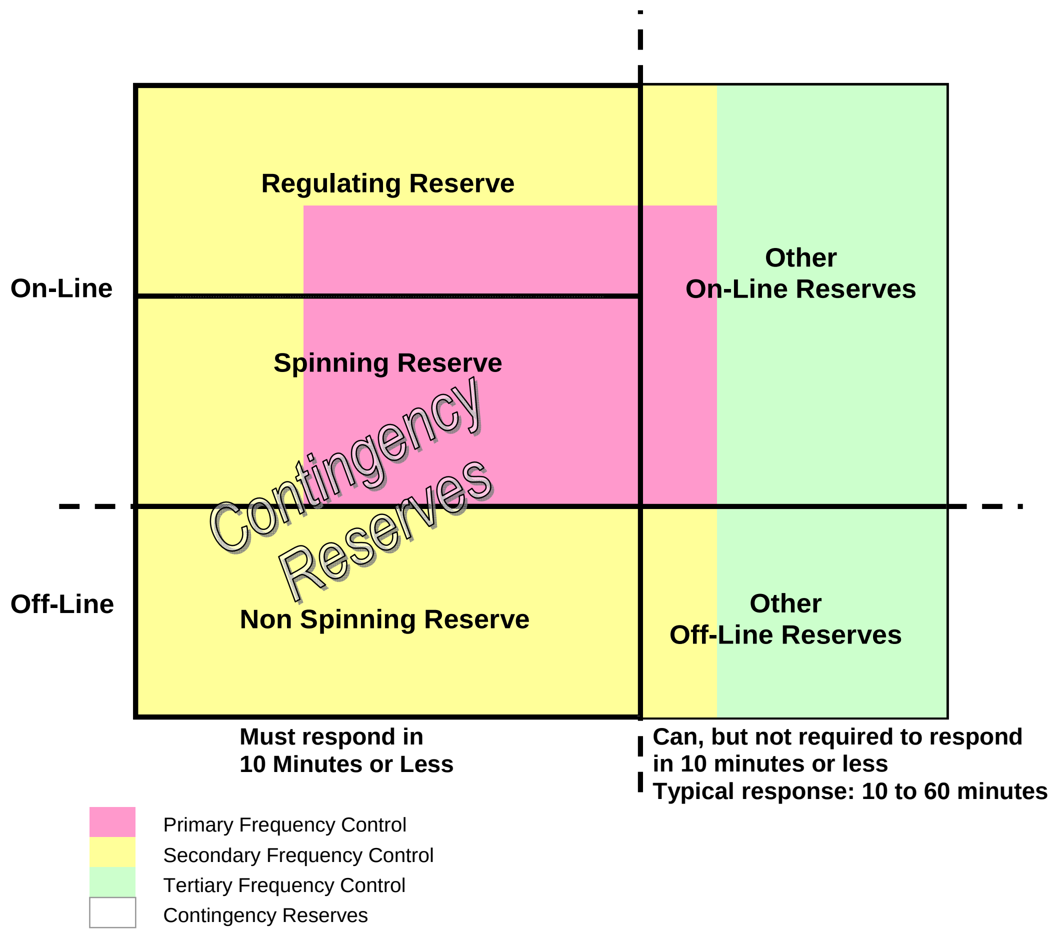
The importance of reliability has led the electric power industry to develop specialized terms and procedures for ensuring that adequate primary and secondary frequency control reserves are always available to manage load variability during normal operations as well as to respond to sudden, large imbalances. Collectively, these forms of frequency control are encompassed in the concept of *operating reserves*.[37]

Generally speaking, operating reserves can be thought of as the difference between the collective capability of the resources (both generation and demand response) available to serve load and the

[37] The discussion in this subsection draws extensively from the presentation of these concepts contained in NERC (2009a).

total load being served. Operating reserves are always positive (i.e., the resources available must collectively exceed total load).

Operating reserves differ based on whether the resources are "on line" or "off line" and how fast they are expected to respond. *On-line reserves* are resources that are running, connected, and synchronized with the interconnection.[38] They include *spinning reserves, regulating reserves*, and *other on-line reserves*. *Off-line reserves* are resources that are not currently running and therefore not synchronized with the interconnection but that can be made available to serve load within a fixed period of time. They include *non-spinning reserves* and *other off-line reserves*. See Figure 2-4.




Source: Based on NERC (2009a)

**Figure 2-4. The Relationship Between Operating Reserves as Defined by NERC and Primary, Secondary, and Tertiary Frequency Control as Defined in this Study**

*Contingency reserves* are a component of operating reserves. These are reserves that have been specifically designated to ensure timely response to loss-of-generation events. Accordingly, they must be capable of responding quickly. Reliability standards require that they be deployed such

[38] Earlier, the term "head room" was introduced as a way to describe the reserve capability of an on-line resource, as measured by its ability to increase output beyond its current operating point.

that the balancing authority achieves the Disturbance Control Standard.[39] Both spinning and non-spinning reserves are used to provide contingency reserves.[40]

*Regulating reserves* are another component of operating reserves that provide regulation. As discussed earlier, the output from generation resources that are explicitly designated for provision of regulation is controlled centrally via dispatch signals from AGC systems. Accordingly, these reserves must be on line.

The remaining reserves (called other on- and off-line reserves) consist of generation that is on line and running at less than full capability or generation and demand response that can be deployed quickly. These reserves might or might not be able to respond within 10 minutes or less.

It is important to recognize that the formal definitions for the various forms of operating reserves do not make explicit reference to the provision of primary and secondary frequency control actions described earlier in this section. This can be a source of confusion, so it is useful to clarify some of the relationships between operating reserves (as defined by NERC) and the provision of primary and secondary frequency control actions (as defined in this study). See Figure 2-4.

As we have discussed, only primary frequency control actions (and in extreme circumstances, under-frequency load shedding) are capable of arresting and stabilizing frequency following the sudden loss of generation. The spinning reserve component of contingency reserves is procured specifically to respond to these events. Yet, the NERC Glossary of Terms Used in Reliability Standards defining spinning reserves does not specifically require that the reserves must be capable of providing primary frequency control actions.[41] As a result, spinning reserves may also be composed of on-line resources capable of providing only secondary frequency control actions.

In point of fact, following the sudden loss of generation, primary frequency control actions will be provided by all on-line generating resources with operating governors and head room. Therefore, if they are capable of doing so, regulating reserves and other on-line reserves will also participate automatically and immediately in responding to a sudden loss of generation.

The important point here is that, following the sudden loss of conventional generation, frequency decline will be arrested and stabilized by the combined effect of all sources that provide primary frequency control, regardless of whether they are formally designated as on-line contingency

[39] Note that this description of the performance requirement for contingency reserves does not make reference to either primary or secondary frequency control. This point is examined through simulation studies presented in Section 5.

[40] We use the term "spinning reserves" to refer *only* to the component of contingency reserves that are synchronized (i.e., on line). Spinning reserve is sometimes used to refer to all on-line operating reserves, including both those that are relied on for regulation and contingency reserves, as well as other on-line reserves not specifically designated to provide either regulation or contingency reserves.

[41] Spinning reserve is defined in the NERC Glossary as "Unloaded generation that is synchronized and ready to serve additional demand."

(i.e., spinning) reserves. This recognition will figure prominently in our discussion of a primary frequency response metric in the next subsection and in the analyses presented in Sections 3 and 5 of this report.

Similarly, generation that can be centrally dispatched by AGC is procured specifically to provide regulation. As discussed, regulation provided via AGC is an automated form of secondary frequency control. If, however, the amount of regulation procured is inadequate and cannot fully address deviations in frequency, then primary frequency control reserves available from other on-line sources (i.e., spinning reserves and other on-line reserves) will also be used (automatically) to control frequency. When this happens, the reserves of primary frequency control available to provide additional primary frequency control actions will be reduced. This creates a reliability risk because primary frequency control reserves may be exhausted or depleted to the point where they are no longer capable of arresting declining frequency following the sudden loss of generation. This interaction between primary and secondary frequency control reserves during normal operations will emerge as an important although not yet well-recognized aspect of the reliability impacts of variable renewable generation and will be discussed in Sections 3 and 6 of this report.

## 2.4 Introduction of Frequency Response Performance Metric to Assess the Adequacy of Primary Frequency Control Reserves

As discussed throughout this section, the ability of a power system to withstand a sudden loss of generation depends on the adequacy of operating reserves that are on line and capable of providing primary frequency control. We now introduce the three frequency response performance metrics that we will use to assess the adequacy of primary frequency control reserves.

We first re-state our definition of adequacy formally in terms of the reliability objective served: Primary frequency control reserves are adequate if they are capable of ensuring the uninterrupted delivery of electricity following the sudden loss of generation.[42] In other words, reserves are adequate, if, following a sudden loss of generation, the primary frequency control actions provided by these reserves successfully arrest and stabilize frequency decline prior to the dropping of firm customer loads through the extreme actions of under-frequency load shedding (assuming there is adequate transmission to ensure deliverability).

[42] The amount of generation as used here is intended to be the largest experienced generation loss and not the magnitude of the largest single generator. This is consistent with the NERC's Procedure for Setting Interconnection Frequency Limits, which describes the determination of the number of allowable contingencies as follows: "This should be a minimum of two contingencies, so that the Interconnection is always at least one contingency away from an Under Frequency Load Shed, but may be greater based on a statistical analysis of contingency probabilities." (NERC 2003)

**The Use of Simulation Tools to Study the Frequency Response of Interconnections Following the Sudden Loss of Large Conventional Generators**

Simulation tools are routinely used by the industry to study, among other things, the dynamic performance of the interconnections in response to system events that result in major perturbations of voltage, frequency, and flows of power. The tools are used to conduct "what-if" studies of various scenarios of past, current and future operating conditions of the power system. Industry uses these tools on an ongoing basis to assess system capabilities in all the time frames to establish operating limits, which in turn affect generation dispatch, transmission flows, and voltage profiles.

The tools contain detailed representations of the operation of generators and their automatic controls, the transmission system, including under-frequency and other load shedding relays, and the response of loads to changes in the power system. A typical dynamic simulation seeks to model the behavior of a power system over about the first 20 seconds following a postulated "what-if" event, such as the sudden loss of a large conventional generator. Twenty seconds is about the longest period of time over which the effectiveness of these controls, acting alone (i.e., without the influences of other changes to the power system, including slower control actions), can be modeled and assessed.

The modeling seeks to replicate the expected behavior of the power system at every instant of time following this event, especially the actions of automatic controls, such as the generator governors that provide primary frequency control. Simulations provide detailed information on the expected behavior of the power system at much finer resolution than can be observed in the field with traditional grid monitoring technologies. For example, simulations can be used to study the expected frequency nadir following a loss-of-generation event, while traditional grid monitoring technologies can only reliably measure settling frequency.[1] Thus, simulation tools are a powerful and essential complement to field measurements in studying and establishing operating limits to ensure reliability.

[1] Recent deployment of higher resolution grid monitoring technologies have proved invaluable in further validating simulation results and promise to make these phenomena visible to power system operators and planners on a routine and on-going basis. See, for example, http://www.naspi.org/

This definition allows us to focus on the most important aspect of frequency behavior following the sudden loss of generation, namely, the point at which frequency is arrested or the *frequency nadir*. If frequency nadir is greater than (i.e., frequency is arrested above) the highest set point for under-frequency load shedding, then the primary frequency control reserves that were in place at the time generation was lost were adequate. If, however, frequency decline is not arrested and frequency crosses below the highest set point, firm customer loads will be dropped through the actions of under-frequency load shedding. This means the primary frequency control reserves that were in place were inadequate.

The first metric to be introduced here, ***frequency nadir***, therefore, is a direct measure of the adequacy of primary frequency control reserves. It is a lagging or after-the-fact metric because it is based on the measured (or simulated) effects of primary frequency control. It determines whether primary frequency controls were able to arrest the excursion before under-frequency load shedding was triggered. See Text Box

*Frequency response* is the traditional metric used by the industry to describe how an interconnection has performed in stabilizing frequency after the loss of generation. It, too, is a lagging metric. The industry measures frequency response by relating the size of the loss-of-generation event (the amount of generation lost) to the resulting net change in system frequency once frequency has been stabilized (at Point B). See Figure 2-5. The units of frequency response are megawatts (MW) per 0.1 Hz. Technically speaking, frequency response must be a negative number for an interconnection to be stable (increased power output in reaction to a decrease in frequency). However, by convention, it is described as a positive number, such as "1,500 MW/0.1Hz" (that is, the negative sign is assumed implicitly).

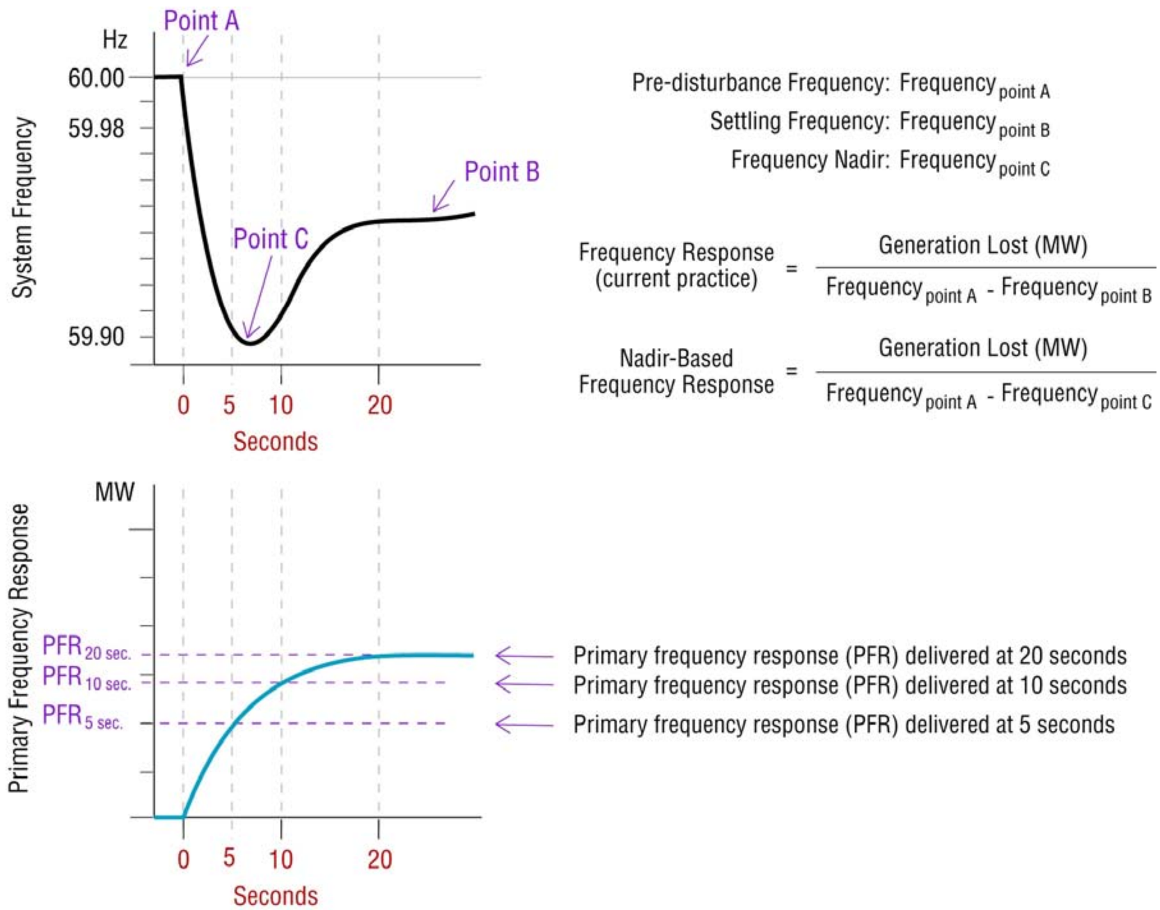



**Figure 2-5. Frequency Response Performance Metrics**

Frequency response is a useful metric for examining trends in quality of frequency control by an interconnection. Martinez (2010), in a technical report prepared for this project, presents a historical analysis of the frequency response of the three U.S. Interconnections. Martinez et al. (2010) report that the median frequency response of both the Eastern and Western Interconnections declined by about one-fourth over the period 2002 to 2008. See Section 4.

For this study, we modify the definition of this traditional metric to focus on the aspect of frequency control that, as discussed previously, is most important for reliability immediately following a loss-of-generation event, which is the frequency nadir.[43] To distinguish our version

[43] One reason the traditional definition of frequency response is based on settling frequency (Point B) is that until recently power system monitoring technologies could not reliably measure frequency nadir (Point C). Frequency nadir could only be studied with simulation tools, such as those that will be used in Section 5 of this report. Advances in power system monitoring technologies have now made it possible to measure frequency nadir in the field.

from the traditional definition, we label the second metric ***nadir-based frequency response.*** It is also a lagging indicator that relates the size of the event (i.e., the amount of generation lost) to the decline in frequency until arrested.

The third metric which we introduce here, called ***primary frequency response***, measures the performance of primary frequency control reserves in opposing deviations in frequency, in this case that are caused by the sudden loss of generation. It is expressed as the power provided by primary frequency control actions at specific points in time following the generation loss event. It can be used both as a leading metric to establish whether primary frequency control reserves are capable of preventing the interruption of electric service to customers following the sudden loss of generation, as well as a lagging metric measuring the actual power output from primary frequency control actions.

Focus on frequency nadir means that the most important performance characteristic of primary frequency control is the rate at which generator power output increases (or, with demand response, the timing and amount of load taken off the power system) following the sudden loss of generation. That is, conceptually speaking, the nadir is formed when the power provided by primary frequency control exactly offsets the amount of net generation that was lost,[44] thereby re-establishing the balance between generation and load.

As a result, it is tempting to define a primary frequency response metric in terms of the power injected into the power system at the point of the nadir of frequency. However, to do so would limit the usefulness of the metric. That is, the frequency nadir is determined by the inertia of the power system at the time generation is lost and the amount of generation lost, in addition to the amount of power provided by the actions of primary frequency control reserves. Establishing adequacy for only a specific set of conditions provides little information regarding the adequacy of these reserves under other conditions (e.g., at times of higher or lower inertia or following the loss of more or less generation). It is more useful to measure the performance of reserves for primary frequency control independent of any specific set of conditions and then assess whether that performance is adequate by considering various alternative sets of conditions.

To do this, we must recognize that primary frequency control actions evolve over time. Therefore, we assess the performance of the reserves that are in place to provide primary frequency control using a metric that measures the power provided by these reserves at different points in time. As discussed earlier in this section, two time frames are of primary importance for primary frequency control actions: First, during the approximately initial 10 seconds following the loss of generation when frequency decline must be arrested. Second, during the period after frequency has been stabilized and up through the time when secondary and tertiary frequency control restore reserves of primary frequency control (roughly 15 minutes or so following the sudden loss of generation). For the purpose of this study, our focus is on examining primary frequency response metrics for this first period, which is the critical period

[44] Net generation is the amount of generation lost less any changes in load due to load-damping. As noted in Footnote 31, load damping refers to the sensitivity of load to changes in frequency and voltage following the sudden loss of generation. Because the effects of load damping on frequency nadir are not affected by the dispatch of reserves providing primary frequency control, we do not describe this effect explicitly in our discussion.

when frequency decline must be arrested before it falls below the highest set point for under-frequency load shedding.

Primary frequency response is the leading metric that will be used by this study to assess the adequacy of primary frequency control reserves. Adequacy is established by determining, for a given amount of generation loss, whether the rate of power output (measured at specific points in time following the loss of generation) will arrest frequency (i.e., form a frequency nadir) at a frequency higher than the highest set point for under-frequency load shedding within an interconnection.[45]

In Section 3, we use these metrics to describe how variable renewable generation can affect the amount and availability (i.e., the adequacy) of primary frequency control reserves necessary to ensure reliability following the sudden loss of conventional generation. In Section 5, we use commercially available simulation tools to examine these effects for each of the three U.S. interconnections using these metrics. And, in Section 6, we refer again to these metrics in discussing effects related to the interaction of primary and secondary frequency control reserves that cannot be studied with today's commercially available simulation tools.

### 2.5 Summary

Reliability practices seek to ensure that, following the sudden and unplanned loss of large conventional generators, an interconnection will continue to deliver electricity to customers without interruption. Ensuring reliability in these circumstances depends on the continuous availability of a critical component of operating reserves called primary frequency control reserves. These reserves are normally provided by generating units that are on line and operating below their full generating capability.[46] Following the sudden loss of a large conventional generator, the automatic, autonomous, and immediate increase in output from these resources seeks to quickly arrest and stabilize the frequency of an interconnection, usually within 10 seconds or less. If the actions of these primary frequency control reserves are inadequate, frequency will continue to decline, and customer loads will be interrupted through the automatic actions of an extreme measure of last resort, called under-frequency load shedding. Under-frequency load shedding involves interrupting electric service to large, pre-set groups of customers; these customers will experience a blackout. Shedding large amounts of load in this manner is a drastic action (because customers' electric service is interrupted) that can have unintended consequences (because it may lead to an even wider spread blackout). Operators, therefore, strive to ensure that primary frequency control reserves are always adequate to arrest frequency decline following the sudden loss of large conventional generators and prevent the triggering of under-frequency load shedding.

The reserves that are required to provide primary frequency control will depend on the size and composition of a power system (as measured by its inertia), the size of the loss of generation

[45] For completeness, the metric should also be used to address the longer period of time over which primary frequency control actions are required; for example, maximum power output should be sustained continuously for 15 minutes following the loss of generation.

[46] Later in this report (in Section 7), we discuss a number of technological options for expanding the supply of primary frequency control resources to include demand response and energy storage.

events the power system is expected to withstand, and the set points for under-frequency load shedding, which establish the lowest acceptable frequency nadir following the sudden loss of conventional generation. The adequacy of reserves maintained to provide primary frequency control can be assessed using three metrics that measure how these reserves will perform in arresting and stabilizing frequency following the sudden loss of generation. The first metric, frequency nadir, is a direct measure of how close a system has come to interrupting delivery of electricity to customers. The second metric, nadir-based frequency response, relates the amount of generation lost to the decline in frequency until arrested. The third metric, primary frequency response, measures the power actually delivered by primary frequency control actions during critical periods before and after the nadir is formed.

The usefulness of these performance metrics does not depend on the composition of generating plants within an interconnection or the size of the interconnection. They can be used to assess the capability or performance of any power system to deliver electricity uninterrupted following the sudden loss of conventional generation. Consequently, they are appropriate metrics to use to study and plan for changes in any interconnection and to assess success in reliably integrating new resources such as variable renewable generation.

# 3. Using Frequency Response Metrics to Guide and Gauge Success in Reliably Integrating Variable Renewable Generation

This section describes how the frequency response metrics developed for this study can be used to guide and gauge success in reliably integrating variable renewable generation. It first reviews the factors that determine the adequacy of primary frequency control and clarifies that two of these factors, the events the interconnection is expected to withstand and the set points for under-frequency load shedding, will not be affected by integrating variable renewable generation. Focusing on the third factor, the requirements for adequate primary frequency control, it then identifies the four ways that system reliability might be affected by variable renewable generation and discusses how each can be studied using frequency response metrics. Each of the interconnections anticipates integration of new renewable generation resources, and in particular, wind generators are the primary resources expected to be integrated in the near term.

The discussions in this section draw from a technical report commissioned for this study, which is published separately (Undrill 2010).

## 3.1 The Reliability Impacts of Integrating Variable Renewable Generation Depend on the Adequacy of Primary Frequency Control Reserves

Assessment of the adequacy of primary frequency control reserves to prevent interruption of electric service to customers following abrupt imbalances caused, for example, by the sudden loss of large conventional generation sources can be used as a tool to assess the reliability impacts of integrating variable renewable generation. The requirements for adequate primary frequency control reserves, depends on: 1) the events (i.e., sudden losses of generation) that the interconnection is expected to withstand; 2) the frequency set points at which under-frequency load shedding is deployed; and 3) the efficacy of primary frequency control actions in arresting the rapid frequency decline following these events.

The first and second factors are not expected to be affected by the amounts of variable renewable generation (i.e., 10 or 20 percent) that are expected to be in operation in the near term, so they are described only briefly below. The third factor is expected to be affected by the amount of variable renewable generation that is in operation in the near term, so it is described in detail. The discussion focuses on wind generation because it is expected to be the dominant form of variable renewable generation in the near term.[47]

## 3.2 The Rapid Ramping of Variable Renewable Generation Output is Not Considered an Event Comparable to the Sudden Loss of Conventional Generation

The rapid ramping of variable renewable generation output is not currently, and for the foreseeable future would not be, considered an event comparable to the sudden loss of generation. Extreme ramps in wind output evolve over many minutes, not within less than a second, which is the time scale over which the sudden loss of generation begins to affect

[47] Many of the same considerations will also apply to solar electricity generation; however, because we did not study solar electricity generation, the analysis does not address issues that might be unique to this form of variable renewable generation.

frequency. Individual wind generators are individually small (e.g., 1 to 3 MW in size). The loss of output from the large numbers of individual wind generators contained within a single wind farm due to falling wind speeds or even the high-speed cut-off of generators due to increasing wind speeds may take place rapidly, but the instantaneous loss of the entire output from a farm is unlikely (barring some form of common mode failure that is not related to the rapid change in wind speed[48]).

Indeed, the farms, themselves, are unlikely to become so large that the sudden loss of a single farm would be comparable to the sudden loss of a large conventional generator (i.e., in excess of 2,000 MW), which is routinely considered in studies of interconnection frequency response. However, with very high levels of variable renewable generation, common mode issues might simultaneously and immediately affect a significant portion of the variable renewable generation fleet.[49] Such events could be comparable in size to the sudden loss of a large conventional power plant and thus could be considered among the loss-of-generation events an interconnection is expected to withstand. This is, therefore, an issue that should be revisited in the future.[50]

As we will discuss in Section 3.4.4 and again in Section 6, extreme ramping (especially downward ramping) of variable renewable generation is an important new type of operating situation that must considered by power system operators. However, it is fundamentally different from the contingencies considered in current frequency response studies and in this study. These contingencies all involve abrupt imbalances, such as the sudden loss of generation, to which only primary frequency control actions can respond quickly enough to address.

## 3.3 Variable Renewable Generation is Not Expected to Affect the Set Points for Under-Frequency Load-Shedding

At this time, variable renewable generation is not expected to affect the design of under-frequency load-shedding schemes. These schemes, as discussed in Section 2, are extreme operating measures of last resort. They are put in place as a safety net, to address the extreme operating condition, which arise when portions of an interconnection separate and operate as independent islands.

The frequency set points at which under-frequency load-shedding schemes are deployed vary by NERC region and subregion. The variations reflect regional and subregional differences in the design of the transmission system as well as differences in reliability management philosophies. Some schemes shed large blocks of load at comparatively high frequencies, and some are tiered with successive shedding of smaller amounts of load at progressively lower frequencies. Within

[48] Note that low voltage ride-through, once considered a leading example of this type of problem, is not currently considered an issue in the U.S. because of the improved capabilities of modern wind turbines.

[49] An example of such a common mode issue might be a transmission contingency on a line that simultaneously affects a large number of wind farms, which are all interconnected through a single point to the transmission system.

[50] Some have expressed concern that extreme events simultaneously affecting large amounts of solar photovoltaic electricity generation (e.g., fast-moving, widespread cloud cover) might evolve rapidly and thus also begin to resemble the loss-of-generation events that are normally considered.

the U.S., the highest frequency set points for initial blocks of load shedding range from 59.7 to 59.3 Hz. See NERC (2007) and NERC (2008a).

Due to the many factors and design issues that must be considered, changes to the set points for current under-frequency load-shedding schemes would require careful study and extensive coordination. Consequently, for the foreseeable future, we conclude that the frequency set points and the blocks of load that will be shed by these schemes are unlikely to be affected solely by the amount of variable renewable generation.

## 3.4 The Adequacy of Primary Frequency Control Reserves is the Principal Impact of Variable Renewable Generation on Reliability

The principal impact of increased variable renewable generation on reliability is the effect of this generation on the adequacy of primary frequency control reserves. In this subsection, we introduce four distinct ways that increased variable renewable generation might affect the adequacy of these reserves. We discuss how the frequency response metrics developed in Section 2, focusing on primary frequency response (the sole leading metric), can be used to guide system planning and operational measures to enable the successful management of these effects. The remaining sections of this report will describe our work to use these metrics to study each of these effects in greater detail.

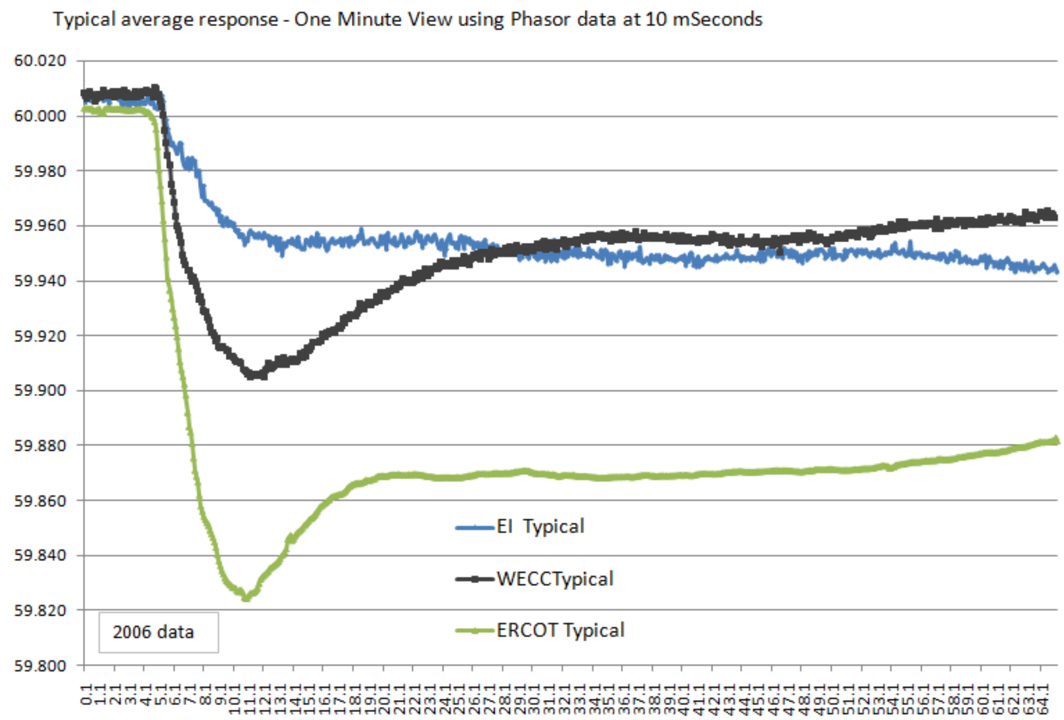
### 3.4.1 Reliability Impact 1: Variable Renewable Generation Will Lower System Inertia

A power system with wind and conventional generation will have less inertia than a similarly sized power system with only conventional generation. Wind-generated electricity is produced by turbines that are connected to the power system in ways that affect the inertia they contribute. From a power system standpoint, these characteristics differ considerably from those of conventional generation. Wind turbines currently contribute either very little inertia (Type 1 and 2 turbines) or essentially no inertia (Type 3 and 4 turbines) (Mullane and O'Malley 2005).[51]

As discussed in Section 2, lower system inertia means that the sudden loss of a given amount of generation will cause system frequency to fall faster than it would in a system with higher inertia. Therefore, to arrest and stabilize frequency at a given frequency nadir (above the highest set point for under-frequency load shedding), a power system with lower inertia will require faster provision of power from primary frequency control actions than will a system with higher inertia. Referring to our third frequency response metric, this means that the primary frequency response required over the initial few seconds will be greater than that required for a system with higher inertia. Conversely, if the primary frequency control reserves are identical for the two systems (and hence the primary frequency control actions and primary frequency response metrics are identical), frequency nadir will be lower for the system with lower inertia following the sudden loss of an identical amount of generation.

[51] Modifications to the controls for Type 3 and 4 wind turbines could enable them to contribute to system inertia. The amount that could be contributed, however, would still be less than that of the conventional generation that is displaced. See review of literature in Section 4.5.

Figure 3-1 shows real-world illustrations of these concepts taken from actual events involving the loss of generation recorded in each of the three U.S. interconnections. Because of the differences in the size of the interconnections (that lead to differences in total system inertia) and the amount of conventional generation lost, the initial rate of frequency decline is greatest for Texas Interconnection; the Western Interconnection has the next greatest rate of decline and the Eastern Interconnection the least. Bear in mind that Figure 3-1 is only an illustration; the amounts of generation lost (especially, when expressed as a percentage of the load size of each interconnection) and primary frequency control actions delivered in each of the three examples are not the same. Hence, the frequency nadirs differ. The effect of the differences in total system inertia is seen primarily in the differences in the initial rates of frequency decline.




Source: NERC (2009a)

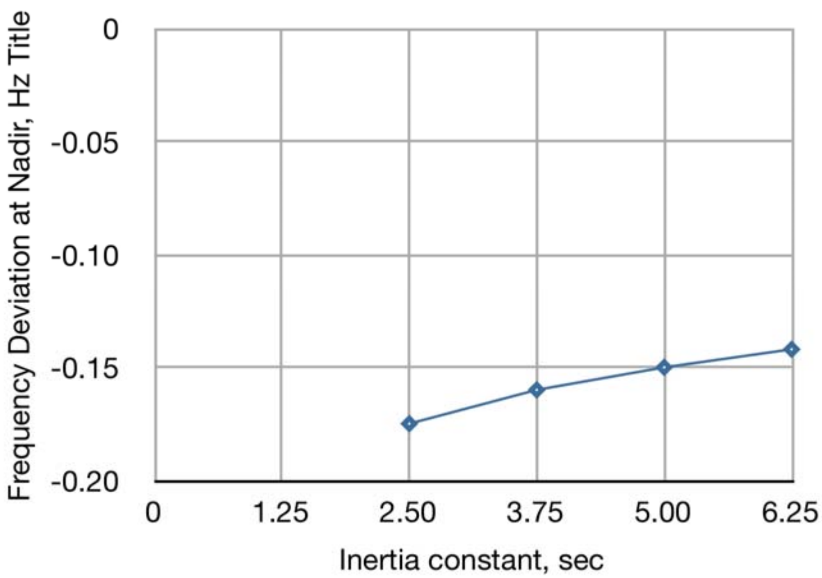
**Figure 3-1. Examples of the Frequency Response of the Three U.S. Interconnections Following the Sudden Loss of Conventional Generation**

Undrill (2010) conducts simplified simulation studies to analyze the relationships between system inertia and the initial rate of frequency decline. Holding constant both the amount of generation lost as well as the amount of primary frequency control reserves, the simulations vary system inertia and report the change in frequency nadir. The normalized system inertias that are considered range from a power system consisting entirely of low-inertia turbines (normalized inertia constant = 2.5 seconds) to a power system consisting entirely of high-inertia turbines (normalized inertia constant = 6.25 seconds).[52]

[52] To put these values into perspective, the normalized system inertias for the Eastern, Western, and Texas Interconnections falls roughly in the middle of this range at approximately 4 to 5 seconds. See Section 5.

The simulations show that when 30% of the generation is providing primary frequency response, a change in normalized system inertia of 250% will result in a change in the frequency nadir of only 23%. Thus, the effect of increased variable renewable generation in lowering system inertia is likely to be a minor effect in establishing requirements for adequate primary frequency control.

In addition, Figure 3-2 indicates that the low-inertia system experiences a nadir about 0.04 Hz deeper than the nadir of the high-inertia system. This finding highlights the critical interaction between declining system frequency and primary frequency control actions. In the four simplified power systems with four different levels of normalized inertia, the rate at which power was delivered through primary frequency control actions is roughly the same.[53] However, because frequency declines faster in the power system with lowest inertia, that system's frequency is arrested at a lower value.




Source: Undrill (2010)

**Figure 3-2. The Relationship Between Frequency Nadir Following the Sudden Loss of Generation and System Inertia**

These simulations reinforce the observation made in Section 2 that the most important quality of primary frequency control action is the rate at which power increases over the initial 15 or so seconds following the loss of generation. If sufficient amounts of power are not injected promptly, frequency will not be arrested before declining to a point at which under-frequency load shedding is triggered.

This insight leads naturally to the role that the primary frequency response metrics developed in Section 2 can play in proactively establishing the requirements for adequate primary frequency

[53] The rate at which power increases is not identical because the rate is inversely proportional to deviation of frequency from the scheduled value. Hence, the rate is actually slightly greater in the system with lower inertia because frequency declines at a faster rate in this system.

control reserves in order to manage frequency as the generation and system inertia change. Recall that the primary frequency response metric is actually a series of metrics that describe the total power delivered by primary frequency control reserves at specific points in time following the sudden loss of a conventional generator. As system inertia changes, based on both the amount of conventional and variable renewable generation that is on line, the rate (or speed) of frequency decline can then be estimated (through simulation studies) for the assumed amount of conventional generation loss that the interconnection is expected to withstand. Coupled with knowledge of highest set point for under-frequency load shedding, the amount of primary frequency control required to arrest frequency above this set point can then be determined. The amount of primary control can then be expressed using the primary frequency response metrics to establish the performance requirements for the minimum amount of power expected from primary frequency control reserves at each point in time.

The task of the power system operator is then to ensure that the resources providing primary frequency control reserves are capable collectively of meeting or exceeding these minimum requirements. Conceptually, this requires two kinds of information: 1) Information on the changing requirements for primary frequency control, perhaps expressed as a family of curves (see Figure 2-5) that vary based on system inertia; and 2) Information on the combined capabilities of the reserves that are on line and capable of providing and delivering primary frequency control, again perhaps expressed as a curve representing the collective capability of the reserves. Expressed in this simplified manner, primary frequency control reserves are judged adequate if their collective capability exceeds the minimum requirement and if they are deliverable. This approach could be used in both operations and system planning. This approach is also applicable to all types of systems. As noted earlier, the effect of increased variable renewable generation on lowering system inertia is likely to have a minor effect in establishing primary frequency control requirements. The primary frequency response metrics can be used to manage reliable operation of the system under a variety of change scenarios.

### 3.4.2 Reliability Impact 2: Variable Renewable Generation May Displace Reserves that Provide Primary Frequency Control

Currently, the majority of wind turbines installed in North America are not equipped to take the action necessary to provide primary frequency control,[54] so the reserves for primary frequency control must be provided by other sources, such as partially unloaded conventional generation with operating governors or demand response.[55] If conventional generation units that were previously expected to provide primary frequency control are decommitted (i.e., taken off line)

[54] Undrill (2010) observes that wind is not alone among the types of generation today that do not provide primary frequency control. Other generation types that do not provide primary frequency control include large natural gas combined-cycle plants whose steam turbines are operated with their valves either wide open or controlling steam pressure, nuclear plants operated at constant power with their turbine control valves being used to control steam pressure, and large coal plants run at maximum output.

[55] Primary frequency control actions can also be provided by demand response, i.e., from customers equipped with frequency-responsive automatic load curtailment devices. However, the discussions in this section refer only to primary frequency control actions provided by conventional generation because this is currently the predominant means by which this form of frequency control is provided. Newer solutions, such as frequency-responsive demand response or provision of primary frequency control actions by wind turbines, are addressed in Section 7 of this report.

as a result of the economic dispatch of variable renewable generation, the remaining primary frequency control reserves may no longer be adequate.

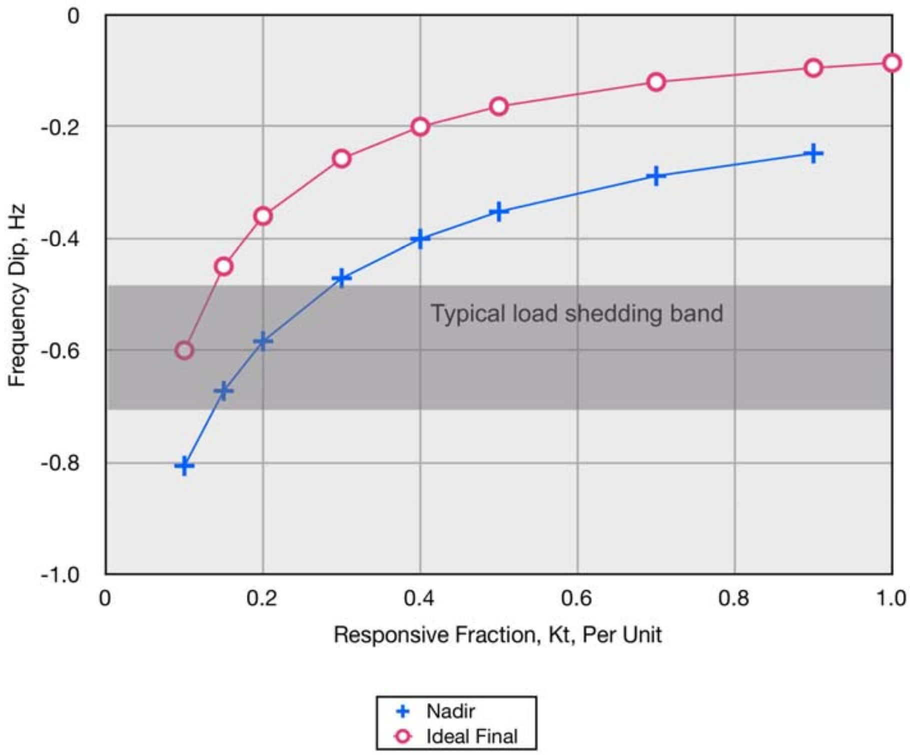
Current dispatch procedures may need to be changed to ensure adequate reserves are always kept on line that can take the actions necessary to provide primary frequency control. One example of possible changes in current procedures might be at times of minimum system load. At these times, baseload units are kept on line for economic reasons. Some may be running at full output and therefore have no head room available for primary frequency control actions. Others might be operated with their governors disabled or with governors that can respond only very slowly. These are the times when wind generation output has been observed to be greatest. Thus, to accommodate the combined output from both wind and baseload generation, very little load may remain for other sources of generation to serve.[56] Yet, it is essential that the sources of generation that are kept on line can provide primary frequency control at the rates required to arrest and stabilize frequency following the sudden loss of large conventional generators. In the extreme, either or both wind and baseload generation may have to be curtailed to create enough room for other sources of frequency-responsive generation to remain on line (e.g., at minimum load), so that they can provide primary frequency control or other sources of primary frequency control, such as demand response or energy storage devices, will need to be developed.

Another set of simulations from Undrill (2010) illustrates relationships among the fraction of generating units that provide primary frequency control, the rate at which units of different generating technologies can deliver primary frequency control actions, and the resulting frequency nadir following the sudden loss of a fixed amount of generation. See Figure 3-3 and Figure 3-4.

Figure 3-3 shows how the frequency nadir following the sudden loss of a given amount of generation increases as the fraction of remaining generation providing primary frequency control increases. In this example, the frequency nadir is progressively higher as the fraction of generation providing primary frequency control increases. This example shows that there must be a minimum amount of primary frequency control in order to arrest frequency prior to under-frequency load shedding. Note, too, that the effect of primary frequency control on frequency nadir begins to diminish as the fraction of generation providing primary frequency control increases to very high levels.

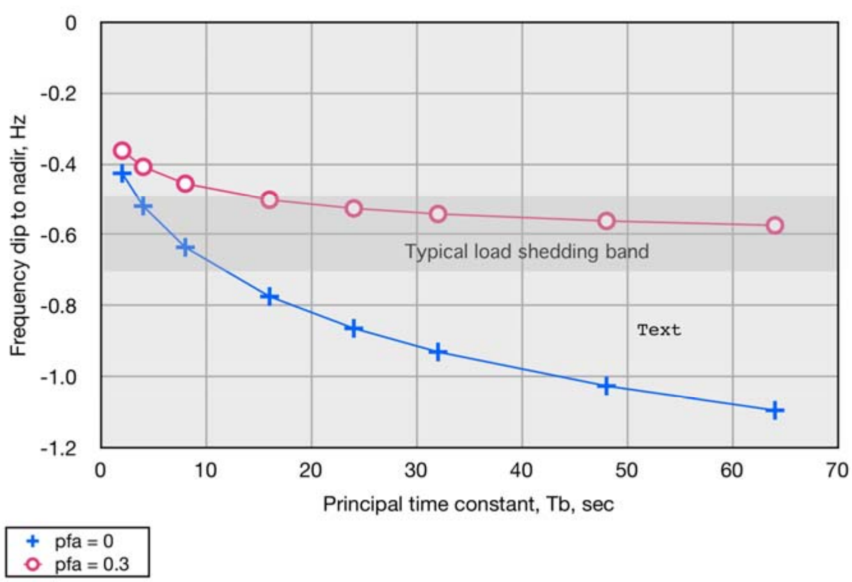
Figure 3-4 holds the amount of generation providing primary frequency control fixed (at 30 percent) and shows how the frequency nadir is affected by the speed or rate of delivery of primary frequency control The rate of delivery of primary frequency control is expressed using a time constant, which measures how long it takes the delivery of primary frequency control to reach its maximum. In this example, the frequency nadir is progressively higher as rate of delivery of primary frequency control increases. This example shows that if delivery of primary frequency control is too slow, it will not be capable of arresting frequency prior to under-frequency load shedding.

[56] Such minimum load situations may become less frequent as the load shape of the interconnections may change with electrification of transportation and deployment of smart devices.




Source: Undrill (2010)

**Figure 3-3. The Relationship Between Both Settling Frequency and Frequency Nadir Following the Sudden Loss of Generation and the Amount of Primary Frequency Control Reserves**




Source: Undrill (2010)

**Figure 3-4. The Relationship Between Frequency Nadir Following the Sudden Loss of Generation and the Rate of Power Injection via Primary Frequency Control Actions.**

These simulations reinforce the basic observation that, to a first approximation, the amount of primary frequency control reserves required depends solely on system inertia, the size of the loss-of-generation events the system must be capable of withstanding, and the highest set point for under-frequency load shedding, which must be avoided. In Section 5, we will study this interaction to assess how dispatching practices for operating reserves affect the amount of primary frequency control reserves that are available to respond to the sudden loss of large conventional generators.

Undrill (2010), in commenting on the simulations, further observes that primary frequency control need not be provided by each generating unit as long as the total amount required can be delivered by the units designated for providing it. Prudence -- and the deliverability consideration discussed next -- suggests, however, that requiring a small contribution from a large number of units creates less risk than requiring a large contribution from a small number of units (WECC 2009b). See Text Box. The challenge presented by increased wind generation is that the displacement of frequency-responsive conventional generation means that the required primary frequency control must now be obtained from the smaller, remaining pool of conventional frequency-responsive generation (or other sources). Hence, the desire to spread the required primary frequency control over a larger number of sources is more difficult to accomplish absent the development of other sources of primary frequency control reserves.

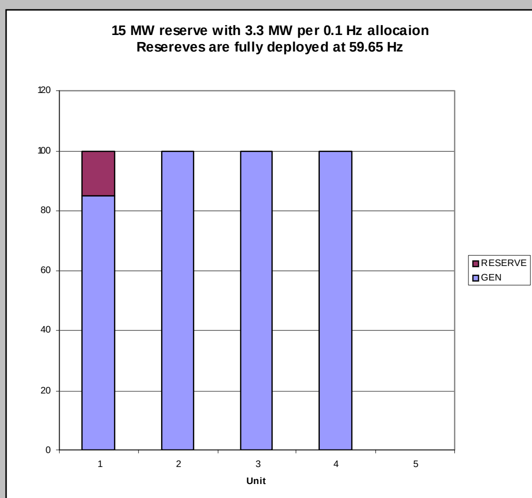
These relationships help to explain other aspects of the frequency behavior of the three interconnections depicted in Figure 3-1. Once arrested, the frequency of both the Texas and Western Interconnections is then stabilized at an even higher value (though, still lower than 60 Hz) because the amount of primary frequency control action delivered in response to the initiating loss-of-generation events is in excess of the amount required to simply arrest the frequency. Using the above figures, this would indicate that a reasonably high percentage of the generators have fast acting governors that do not withdraw their output until the frequency increases. For the Eastern Interconnection, the amount of primary frequency control action delivered arrests the frequency decline but does not stabilize it at a higher value. Again using the above figures, this would indicate that a relatively smaller percentage of generators are providing primary frequency control. The continued downward, albeit slower, slope of frequency after the inflection point (the point at which frequency might first appear to be arrested), furthermore, appears to be indicative of the withdrawal of primary frequency control action, possibly by plant secondary controls.[57]

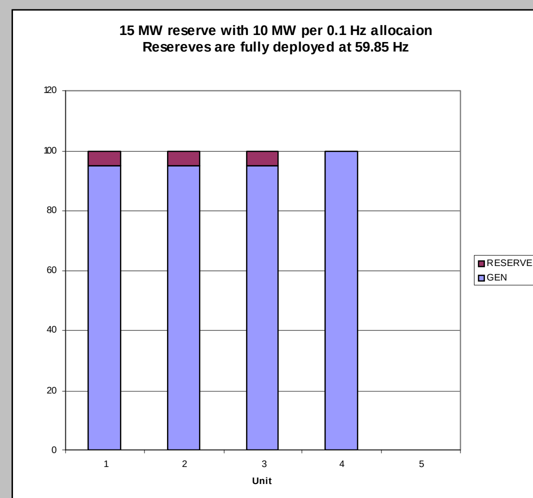
[57] Aspects of this topic, which are not related to the amount of wind generation on the power system, are continued in Section 4.1 and in separate technical reports prepared for this study by Martinez (2010) and Undrill (2010).

**Frequency Nadir Depends on How Reserves for Primary Frequency Control are Allocated**

Comments filed by the Bonneville Power Administration following FERC's September 23, 2010 technical conference illustrate how the allocation of primary frequency control reserves among generating units affects the performance of an interconnection in arresting frequency following the sudden loss of conventional generation. Performance is measured by the frequency nadir.

In the figure on the left, all primary frequency control reserves are allocated to a single generating unit. In the figure on the right, these reserves are allocated in smaller amounts equally to three generating units. In both cases, the frequency droop setting is equal for all generating units. Droop is a measure of the change in power output (limited by the capacity of the generator) that a generator will produce for a change in frequency.




BPA's simulations of these two allocation approaches indicate that the frequency nadir will be three times lower for the allocation in the figure on the left than the allocation in the figure on the right.

These findings suggest that, other things being equal, faster delivery of primary frequency control will result when greater numbers of generating units are each required to deliver a small portion of the total requirement than when fewer units are required to deliver proportionally larger portions of the total requirement. As illustrated in the left figure above, one unit with 15 MW of reserves will provide 3.3 MW for a 0.1 Hz frequency decline compared with three units illustrated in the right figure above, each with 5 MW of reserves will produce 10 MW for the same frequency deviation, thereby providing a faster speed of delivery.

The primary frequency response metrics developed in Section 2 are uniquely well-suited to study and manage situations when the economic dispatch of variable renewable generation will displace reserves that provide primary frequency control. As discussed at the end of Section 3.4.1, careful study of the inertia of the interconnections as the amount and characteristics of on-line generators (both conventional and variable renewable) changes, identification of the loss of generation events the interconnection is expected to withstand, and knowledge of the highest set points for under-frequency load shedding lead naturally to the use of primary frequency response metrics to articulate the minimum requirements for primary frequency control reserves in order to ensure reliability. Articulation of these requirements, which change based on system inertia, then establishes a threshold for the collective capability of the resources expected to provide primary frequency control reserves. Operators must then ensure that this minimum is on line, available, and deliverable. As the output from variable renewable generation changes, operators must consider the effects of these changes on system inertia and the capabilities of the available primary frequency control reserves. Section 3.4.1 offered a simplified conceptual example outlining this process. The primary frequency response metrics can be used by operators to identify and deploy the actions necessary to ensure that the minimum required reserves of primary frequency control are always maintained.

### 3.4.3 Reliability Impact 3: Variable Renewable Generation May Displace Strategically Located Primary Frequency Control Reserves

Reliability Impact 2 discussed displacement of the overall amount of required primary frequency control reserves. Reliability Impact 3 focuses on a related, subsidiary issue that stems from the location of the required reserves and potential limitations of the transmission system that might prevent effective delivery of primary frequency control actions when they are needed. The concern is that increased variable renewable generation may displace strategically located primary frequency control reserves. The concern arises, because, as noted in discussing Reliability Impact 2, displacement of conventional generation by wind generation means that, all else remaining the same, the requirements for primary frequency control reserves must be met by drawing from the smaller pool of remaining sources that remain on line and that are capable of providing these control actions.

Primary frequency control actions must be delivered quickly to the locations where they are needed (to make up for or replace the power that was provided by the generation that has been lost). When primary frequency control reserves are distant from the generation that has been lost, the deliverability of primary frequency control actions must also be taken into account. In other words, the location of these reserves and the ability of the transmission system to deliver the primary frequency control actions of these reserves reliably is as important as the total quantity of reserves set aside for primary frequency control.

Deliberate planning is required to ensure that the reserves expected to take the actions necessary to provide primary frequency control are located appropriately within the transmission system so that, when needed, these actions can be delivered reliably in response to the loss-of-generation events that the interconnection is expected to withstand. As the location of these reserves change due to changes in the generation mix, care must be taken to ensure that the primary frequency control expected from these reserves can be delivered. Otherwise, the immediate surge of power from primary frequency control actions and redistribution of power flows following the loss of generation could exceed the capabilities of the inter-ties or transmission interfaces that are being counted on to deliver this power from distant locations. Exceeding these capabilities could trigger a cascading effect leading to even greater interruptions.

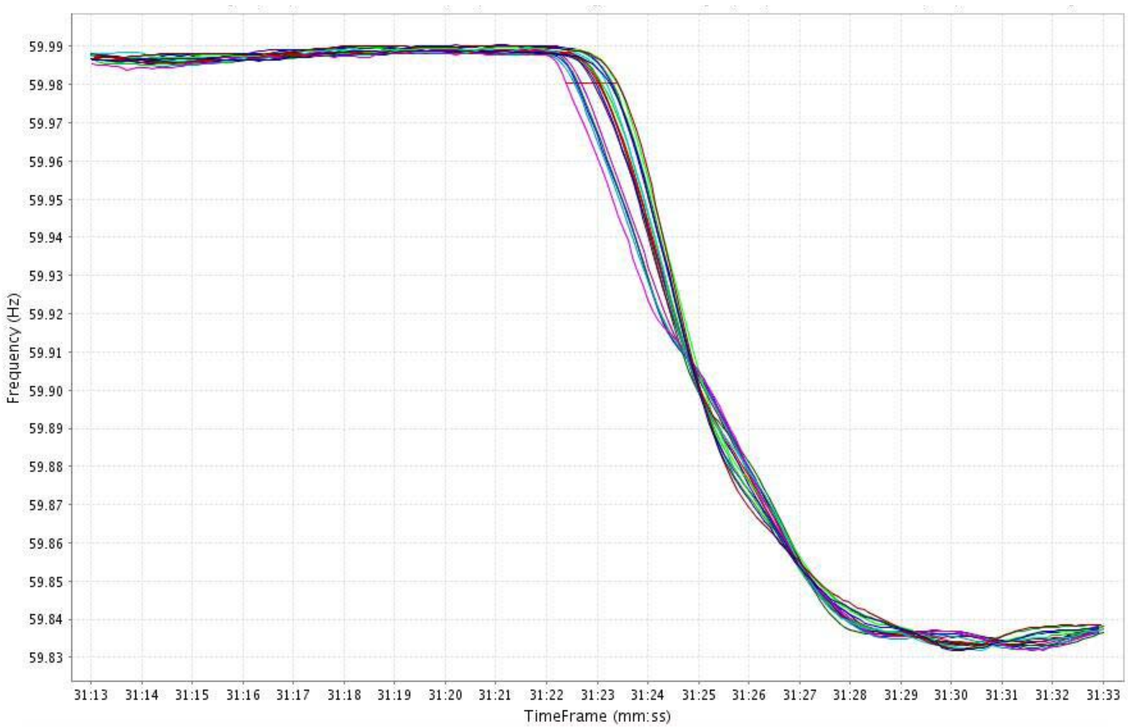
Undrill (2010) conducted another simulation that illustrates the way that reserves in one part of an interconnection are impacted by a loss-of-generation event in another part of an interconnection which quantifies the significance of location of the primary frequency control reserves. In the simulation, power flows across a series of adjacent balancing areas are considered. The balancing areas are lined up sequentially, forming a long chain. The simulation examines how, following the loss of a large conventional generator within the balancing area at one end of the chain, changes in frequency propagate through the balancing areas to the other end of the chain. The simulation shows that the rate at which changes in frequency propagate through the different balancing areas does not substantially depend on the geographic distance or impedance between the balancing areas. Instead the rate of propagation depends on the amount of inertia within each balancing area. As discussed previously, the amount and characteristics of generation and load within in a balancing area determines the inertia of the balancing area.

The simulation confirms and clarifies the physical basis underlying the observation that all interconnected balancing areas will at some point experience a frequency excursion initiated within any other balancing area. The significance of the finding is that, following the loss of generation, all generators capable of taking the actions necessary to provide primary frequency control within the interconnection will in fact respond and participate in arresting the decline in frequency caused by this event, albeit with a small delay in time. Thus, the ability of the inter-ties between balancing areas to accommodate the sudden surge of power from these actions must be taken into consideration. In addition, changes in the location of frequency-responsive resources must be considered.

Figure 3-5 shows a real-world example of this phenomenon. The figure depicts frequencies recorded at increasing distances from a single loss-of-generation event in the Western Interconnection. The time delays between frequencies are directly related to the inertias of the areas between the point at which frequency was recorded and that of the location of the initiating event.

In Section 5, we will address the deliverability of primary frequency control actions, but only indirectly because detailed examination of this issue requires explicit consideration of the topology of the transmission systems within each interconnection, the location of the loss of generation, and the exact pattern of dispatch of operating reserves across the interconnection. Consideration of this level of detail is beyond the scope of the present study.

The primary frequency response metrics developed in Section 2 cannot be used alone to assess the impact of variable renewable generation in displacing strategically located primary frequency control reserves. As described in Sections 3.4.1 and 3.4.2, the metrics can (and should) be used to establish minimum requirements for the collective capabilities of the total fleet of resources deployed as primary frequency control reserves. However, they must be augmented by careful study of the capabilities of each transmission system in order to ensure that the delivery of primary frequency control will not cause other, potentially more severe problems. Further redispatch of resources may be required to address limitations that are unique to each transmission system. Simplified metrics to assist in this process are recommended as a topic for future research.




Source: Genscape, Inc.

**Figure 3-5. Frequency Recordings Made At Different Locations within the Western Interconnection Following the Sudden Loss of a Large Generator**

### 3.4.4 Reliability Impact 4: Variable Renewable Generation Will Require Secondary Frequency Control Reserves In Addition to Those Set-Aside to Provide Primary Frequency Control

From the standpoint of dispatching conventional generation, variable renewable generation is often thought of as a modifier to the aggregate system load that is being served. That is, variable generation is considered a "must-take" resource because it is generally assumed that it will always be utilized whenever it is produced.[58] The term *net system load* is sometimes used to refer to the residual demand (i.e., total system load less variable renewable generation output) that must be served by other generators.[59]

Net system load is more variable and, at present, less predictable than customer loads alone. As discussed in Section 2, power system operators rely on secondary frequency control actions in the form of regulation and load following to maintain scheduled frequency in response to these normal load variations (or net system load). Operators will continue to rely on these actions in the future to maintain system frequency.

[58] As discussed earlier, there are other examples of "must-take" resources, such baseload nuclear and sometimes coal generation.

[59] Net system load refers to the difference between the aggregation of customers' electricity demands (system load) and the aggregation of variable renewable generation output. Since it is normally assumed that variable renewable generation output will be accepted by the power system whenever it is made available, the requirements for generation from conventional generation sources are determined by the residual or net system load that remains.

Studies by others of the operational impacts of variable renewable generation all find that the amount of regulation and load following required in the future by operators to manage the increased variability (and decreased predictability) of net system load during periods of normal operations will be greater than that currently required.[60] If, however, the requirements for secondary frequency control are inaccurately forecast or under-procured, secondary frequency control reserves may be incapable of managing the increased variability in net system load. When this occurs, primary frequency control reserves will act automatically to oppose changes in frequency that, otherwise, would have been opposed solely with secondary frequency control reserves.

Two concerns emerge when the reserves procured to provide secondary frequency control during normal operations prove to be inadequate, and reserves set aside to provide primary frequency control are utilized. First, the remaining reserves for primary frequency control may be depleted and therefore incapable of arresting and stabilizing frequency following the sudden loss of generation. Second, in the extreme, if the reserves for both primary and secondary frequency control have been fully utilized, there will be no operating margin left to respond to any further increase in load (or decreases in generation). Both situations would lead to the same outcome: inability of the interconnection to arrest and stabilize frequency prior to initiation of under-frequency load shedding, leading potentially to cascading outages and a widespread blackout.

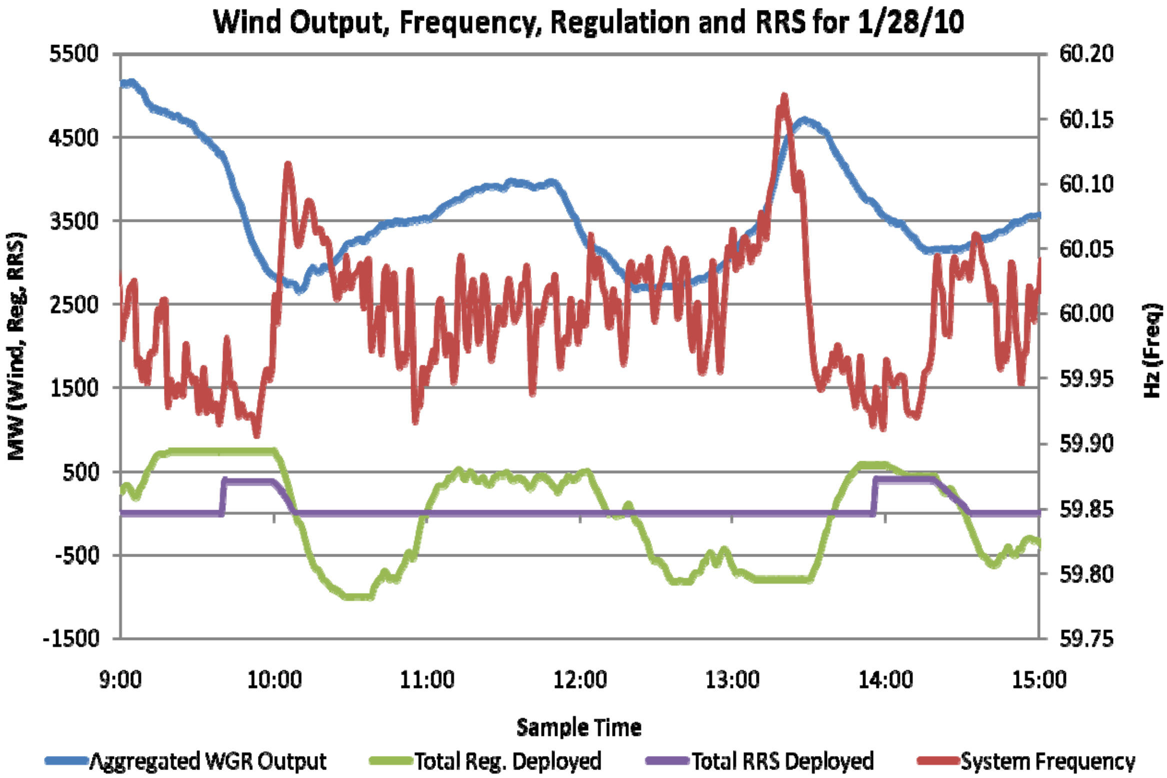
Undrill (2010) conducted a final set of simulations that illustrate interactions between reserves for primary and secondary frequency control in responding to rapid increases in load. The simulations examine operating time frames of 1.5 hours and a load increase of 10 percent during this period, which is consistent with load increases that are routinely encountered in normal operations (independent of wind generation). In one simulation, the head room available from the resources that have the capacity to provide secondary frequency control is constrained, as might occur if inadequate secondary frequency control reserves have been procured. Once the available head room from secondary control reserves is consumed, the head room available from primary frequency control reserves is used next. Once the head room available from both forms of frequency control is consumed, frequency continues to decline unopposed as load continues to increase. This example shows how frequency can decline to levels that would trigger under-frequency load shedding even though there has been no sudden loss of generation.

Figure 3-6 provides a real-world example of these interactions drawn from a recent wind event in the Texas Interconnection.[61] In this example, two downward ramps of wind (starting approximately 9 AM and 1:30 PM) required deployment of primary frequency control reserves (labeled "RRS" for Rapid Responsive Reserves) to augment the actions of regulation to restore frequency (at approximately 9:40 AM and 2 PM). That is, the secondary frequency control actions taken by regulation (and likely the movement of other generation sources not shown on this graph) alone were unable to arrest the decline in system frequency. Consequently, reserves

[60] Section 4 of this study reviews the findings from industry-led studies that estimate the increases in regulation and load following required to accommodate integration of wind generation.

[61] See Attachment 14. Slides for 1-28-10 at http://www.ercot.com/calendar/2010/02/20100204-TAC

that were being held to provide primary frequency control actions were deployed.[62] In contrast, there is also an intermediate downward wind ramp that starts at approximately noon for which it appears that the impacts on frequency were managed solely through increased output from other generation sources, coupled with downward (rather than upward) regulation.




Source: ERCOT (2010).

**Figure 3-6. The Relationship Between Rapidly Changing Wind Output and System Frequency in the Texas Interconnection on January 28, 2010**

Thus, it is imperative to ensure that adequate reserves for secondary frequency control are always available to maintain scheduled frequency during normal operations. This is necessary to "protect" the reserves set aside for primary frequency control so that they will always be available to respond in the very short time available to arrest and stabilize frequency following the sudden loss of large conventional generators.[63]

[62] Despite deployment of the Responsive Reserves that are procured specifically to provide primary frequency control, ERCOT policies ensure that the aggregate capability of resources able to provide primary frequency control always exceeds a minimum requirement, even if some of the resources providing this control were not set-aside initially and specifically designated as Responsive Reserves.

[63] There are related, subtle, yet important, issues that must be addressed involving appropriate dead band settings for generator governors. See, for example, Niemeyer (2010).

In Section 6, we will discuss the operating challenges involved in coordinating reserves for primary and secondary frequency control from the standpoint of ensuring reserves for primary frequency control are always adequate.

The primary frequency response metrics developed in Section 2 are also well-suited for assessing the impact of variable renewable generation in requiring additional secondary frequency control reserves. As with the previous impact, however, they must be augmented by other metrics that, in this case, assess the adequacy of reserves that provide secondary frequency control. Still, the role of the primary frequency response metrics remains fundamental because, as discussed in Sections 3.4.1 and 3.4.2, they establish the threshold below which primary frequency control reserves should not fall. Thus, they should be used in conjunction with metrics for secondary frequency control to determine whether inadequate secondary frequency control will or will not compromise or reduce remaining available primary frequency control reserves below the thresholds required to ensure reliable operation. If, for example, the threshold for primary frequency control reserves would be crossed, then the thresholds established for secondary frequency control reserves should be increased in order to ensure that adequate primary frequency control reserves are always maintained.

## 3.5 Summary

As discussed in Section 2, the requirements for adequate primary frequency control reserves depend on: 1) the events (i.e., the amount of conventional generation that might be lost) that the interconnection is expected to withstand; 2) the frequency set points at which under-frequency load shedding is deployed within an interconnection; and 3) the efficacy of primary frequency control actions in arresting the rapid frequency decline following these events before these set points are crossed.

Increased variable renewable generation is not expected to affect the first two of these factors. The rapid ramping of variable renewable generation output is not considered an event comparable to the sudden loss of large conventional generators and variable renewable generation is not expected to affect the set points for under-frequency load shedding.

We find, however, that increased variable renewable generation will have four impacts on the efficacy of primary frequency control actions and that primary frequency response metrics can be tools to plan for and manage reliable operation following the sudden loss of large conventional generators.

1. Lower system inertia. If the total amount of generation on line remains the same, the system inertia of the interconnections will be lowered by increased variable renewable generation because the dominant form of variable renewable generation currently does not contribute the same inertia to the interconnection as the conventional generation it replaces. While this effect is expected to be less significant compared to the other three discussed next, lower system inertia increases the requirements for primary frequency control reserves in order to arrest frequency at the same nadir following the sudden loss of a conventional generator.

2. Displacement of primary frequency control reserves. The amount of primary frequency control reserves that are on line and available may be reduced as the conventional generation-based sources for these reserves are displaced by the economic dispatch of variable renewable generation, which currently does not provide primary frequency control. As a result, planning and operating procedures may need to be strengthened to ensure adequate primary frequency control reserves are on line and available at all times.

3. Affect the location of primary frequency control reserves. Related to 2 above, the resulting re-dispatch of the resources (generation and demand response) that are expected to provide primary frequency control may lead to transmission bottlenecks that prevent effective delivery of primary frequency control when it is needed. As a result, planning and operating procedures must ensure that adequate primary frequency control reserves are deliverable and therefore are properly located and dispatched within the transmission system. The dispatch must ensure that the reserves can respond immediately to the sudden loss-of-generation events the interconnection is expected to withstand without overwhelming the ability of the transmission system to deliver this response.

4. Place increased requirements on the adequacy of secondary frequency control reserves. The demands placed on slower forms of frequency control, called secondary frequency control reserves, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary frequency control reserves, primary frequency control reserves (that are set-aside to respond to the sudden loss of conventional generators) will be used to make up for the shortfall. The remaining primary frequency control reserves may be inadequate to prevent operation of under-frequency load shedding following the sudden loss of a large conventional generator. As a result, planning and operating procedures must ensure that the required primary frequency control reserves are always protected (and thereby available to respond to loss-of-generation events) by ensuring adequate secondary frequency control reserves.

All four potential impacts are within the scope of responsibility of the planning operating processes involved in assessing, forecasting, scheduling, and dispatching generation and demand response resources in order to meet system demand reliably. All four require careful study and are the focus of the remainder of this report. The metrics introduced here are designed to provide a tool to guide and gauge the extent and success of these operational processes.

# 4. The Motivation for Using Primary Frequency Response Metrics to Study the Reliability Impacts of Integrating Variable Renewable Generation

This section summarizes background research conducted on frequency control and operational integration of variable renewable generation (mainly wind) in the U.S. and internationally. The topics addressed include: the declining quality of frequency control of the U.S. interconnections, industry experiences with and perspectives on the integration of variable renewable generation, recent industry studies of the impacts of wind generation integration on the operation of the power system, international experiences with integrating wind generation, and recent studies of the impacts of wind integration on frequency control.

The discussion of the first topic draws from two technical reports commissioned for this study that are published separately (Martinez et al. 2010, Illian 2010). The second discussion is based on interviews conducted by the project team with power system operators. The third and fifth discussions are based on literature reviews. The fourth discussion is based on interviews and literature reviews conducted by the project team.

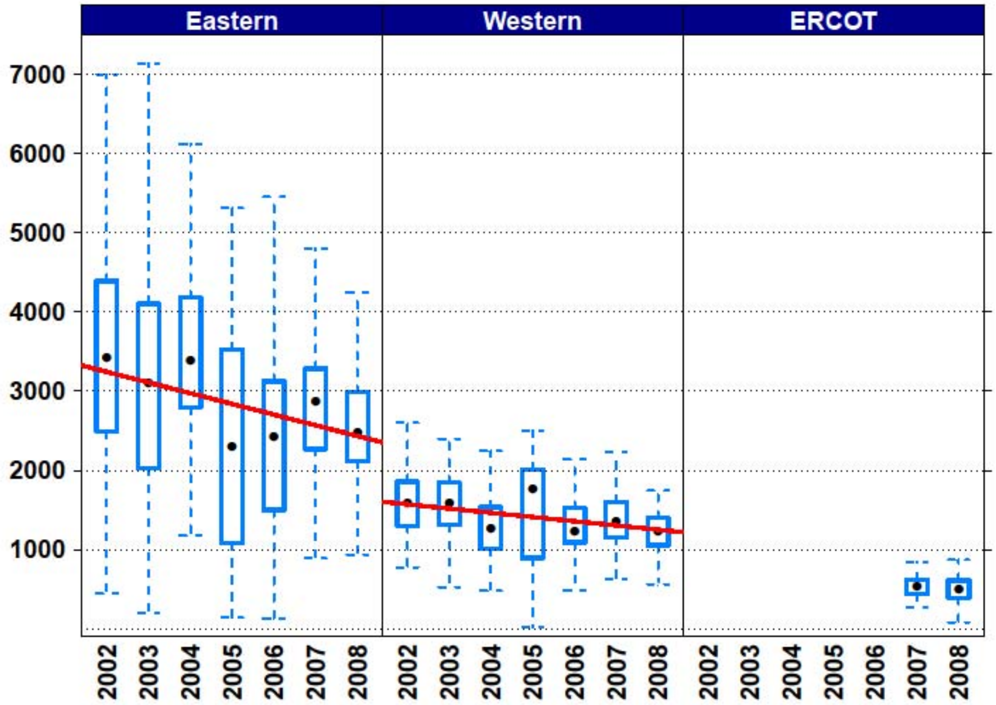
## 4.1 The Quality of Frequency Control of the U.S. Interconnections Has Been Declining

It is widely acknowledged that the industry, especially in the Eastern Interconnection, is currently grappling with the implications of declining quality of frequency control (NERC 2009d, NERC 2010a, NERC 2010b). This subsection summarizes findings from two studies conducted in support of this project that document some of the reasons for these concerns. These findings, along with current industry activities focused on this topic, underscore the timeliness of studying the impacts of increased variable renewable generation on the frequency response of U.S. interconnections.

Martinez et al. (2010) reviews the recent history of frequency performance for all three U.S. interconnections: Eastern, Western, and Texas. The study focuses on the recorded frequency response of each of the interconnections over time and attempts to correlate trends in frequency response to other aspects of frequency performance.

The Martinez study notes that the methods and data available for measuring or calculating interconnection frequency response have evolved over time. The study employs a consistent method for calculating frequency response using the best available data collected by NERC.

Figure 4-1 presents trends in yearly interconnection frequency response from 2002 to 2008. The median frequency response of both the Eastern and Western Interconnections declined by about 1/4 over this period. This finding is consistent with findings of past investigations of frequency response, and the study's use of a consistent calculation method and recent data adds weight to these previous findings (Ingleson 2005). The presented trends for the Texas interconnection do not reflect the significant work performed by ERCOT in the last two years. Discussions with representatives of ERCOT indicate that their frequency response has stabilized above the values shown for 2008 to an average of 640 MW/0.1Hz.




Source: Martinez et al. (2010)

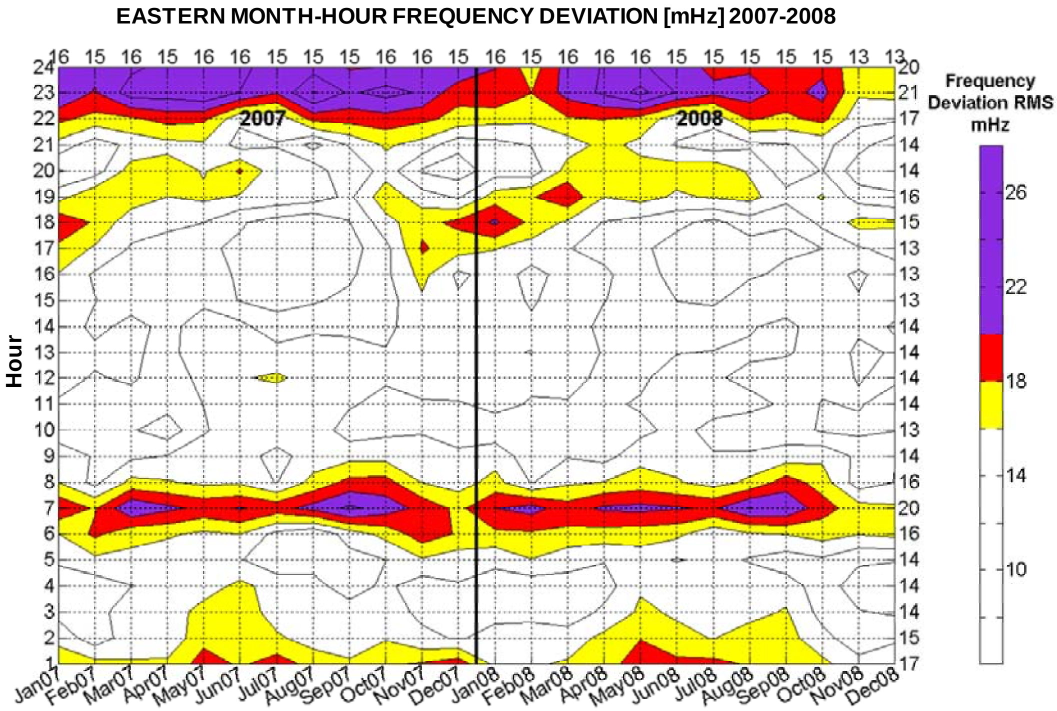
**Figure 4-1. The Recorded Frequency Response of the Three U.S. Interconnections, 2002-2008**

These trends are troubling because they indicate that the quality of frequency control is declining in Eastern and Western interconnections. As discussed in Section 2, frequency response is a lagging metric that normalizes the recorded deviations in frequency by the amount of generation lost. The range of values recorded in a year, which the Martinez study presents for the first time, indicates that performance of the reserves held to provide frequency control is sometimes much lower than the average.[64] Low frequency response values are suggestive of the possibility that had a much bigger event occurred at this time (i.e., when frequency control reserves were this low) a much bigger frequency excursion would have been recorded, potentially one that would have initiated under-frequency load shedding.

The study also examines *frequency deviations*, expressed using the root mean square of the difference between actual and scheduled frequency. These findings conclusively document anecdotal reports that frequency deviations are consistently and predictably larger during the early morning and late evening (see Figure 4-2) and during 5-minute time periods at the top of the hour, compared to other times of the day or hour (see Figure 4-3).[65] These deviations are

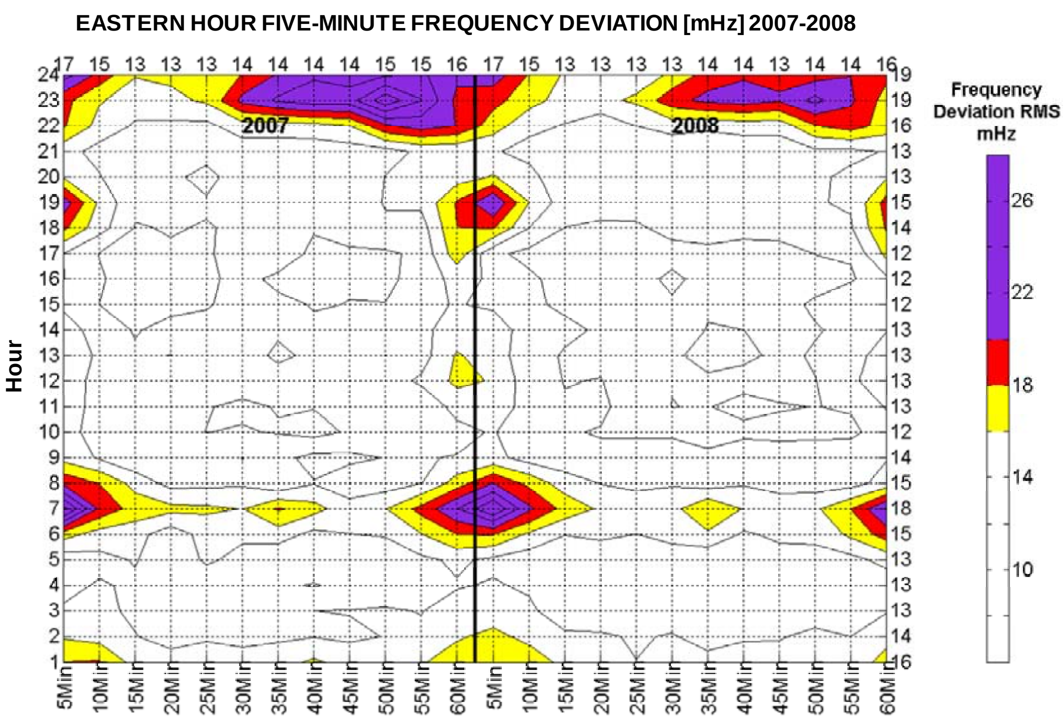
[64] In Figure 4-1, the dot indicates the simple average of the frequency responses recorded each year. The "box" contains 50% of the frequency responses recorded each year. The brackets or "whiskers" above and below the box are calculated values that represent three standard deviations above and below average of the frequency responses recorded each year.

[65] To put the magnitude of the deviations into context, the expected range of random deviations for the Eastern Interconnection has been 18 mHz for many years.




Source: Martinez, et al. (2010)

**Figure 4-2. Eastern Interconnection RMS of Frequency Deviation by Month and Hour of the Day - 2007-2008**




Source: Martinez, et al. (2010)

**Figure 4-3. Eastern Interconnection RMS of Frequency Deviation Hour and Five-Minute Period within the Hour - 2007-2008**

common knowledge within the industry.[66] The periods of greater deviations coincide with market-driven dispatch operations that involve the ramping in and out of large blocks of generation at the beginning and end of the day and electricity transactions that normally begin at the top of the hour. It should be noted that this pattern of frequency deviations is not a function of wind operations. In fact, as we will discuss below, because of the relatively small amount of interconnected wind generators, system operators do not report frequency response impacts of variable renewable generation as a significant operational concern.

Systematically larger deviations in frequency at predictable times of the day or within the hour indicate that the reserves used to provide secondary frequency control have not maintained frequency at the scheduled value at these times, which suggests demands are also being placed on reserves set aside for primary frequency control (as discussed in Section 3). The Martinez study takes a preliminary look at whether the times of day or times within the hour when frequency deviations are greatest correlate with the times when frequency response is lowest. This preliminary examination is statistically inconclusive, in part because of the comparatively small number of large loss-of-generation events that occur at any given time within a year. This topic is recommended for future investigation.[67]

Illian (2010) chronicles the evolution of frequency measurements and management practices. Two aspects of this evolution bear directly on this study of frequency response. First, current frequency control performance measures focus predominantly on the long-term or average performance of secondary frequency control reserves.[68] The historical focus was on averages because it was considered burdensome on entities to assess performance based on a more granular basis given the frequency recording technologies available at the time. Also, it was believed at the time that operating practices could be characterized adequately by average performance. Today, and in the future, operating practices may not be characterized adequately by reliance solely on averages. As discussed in Section 3.4.4 and explored in a preliminary manner by Martinez (2010), it is also important to examine the situations when demands placed on secondary frequency control reserves exceed their capabilities and thus place demands on primary frequency control reserves.

Second, current standards and measures that address the amount and capabilities of reserves set aside for primary frequency control are indirect and measured on an annual average basis.

[66] See, for example, the discussion of system frequency in the 2003 Blackout Report: "The largest deviations in frequency occur at regular intervals. These intervals reflect interchange schedule changes at the peak to off-peak schedule changes (06:00 to 07:00 and 21:00 to 22:00, as shown in Figure 4.12) and on regular hourly and half-hour schedule changes as power plants ramp up and down to serve scheduled purchases and interchanges." (U.S.-Canada Power System Outage Task Force 2004).

[67] In Section 6, we further support this recommendation by describing illustrative scenarios in which rapid and extreme wind ramps first deplete available secondary and then primary frequency control reserves. Should a sudden loss of a large amount of generation occur during this time, frequency response will be lower due to this erosion of primary frequency control.

[68] For example, the applicable Control Performance Standard requires balancing authorities to control their ACE within specific limits for 90% of the time. For the remaining 10% of the time, there are no specified limits. As can be seen in Figure 4-2, the deviations are mostly within 18 mHz which has been the historic expected range of random deviations for the Eastern Interconnection.

Again, the reason for this is that more direct measures were considered burdensome and not necessary given the operating practices at the time they were developed. These two observations help to explain the findings on frequency performance reported in Martinez (2010) and are the basis for current industry efforts to improve measurement and establish improved guidelines for securing both primary and secondary frequency control reserves.

The Illian study observes that the earliest frequency control performance measures focused on the performance of reserves for secondary frequency control because the industry assumed that power system operations could not significantly influence reserves for primary frequency control.[69] This led to the development of operating guidelines and, later, standards based on these guidelines that distinguish between times of "normal" operation and times of "abnormal" operation, i.e., recovery from disturbances, such as the sudden loss of a large amount of generation.

During normal operation periods, current practices, guidelines, and standards seek to codify "good utility" behavior regarding the management and limitation of unscheduled interchanges among the entities known today as balancing authorities. These practices focus on managing *Area Control Error* (ACE) and frequency over time frames of 1 minute or longer. For example, the Control Performance Standard 1 (CPS1) requirement is based on 1-minute averages, and the Control Performance Standard 2 (CPS2) requirement is based on performance measured over 10 minutes; these averages are then further aggregated over the course of an entire year or month, respectively. Finally, the standards for performance are expressed as thresholds that these averages must exceed (NERC 2008c). As a result, these practices target predominantly the average performance of reserves for secondary frequency control and permit operation beyond pre-established thresholds for some portion of time. The historic reasons for this are discussed in Illian (2010).

Practices that focus on shorter-term frequency management are currently restricted to periods of abnormal operations, i.e., following large loss-of-generation events. These practices consist of performance requirements for the restoration of system frequency but do not prescribe the relative roles of reserves for primary and secondary frequency control in this process. See Figure 2-4 and accompanying discussion in Section 2.3.

Recently, the industry has recognized the importance of focusing on frequency deviations in time frames of less than 1 minute during periods of normal operations. As a result, the industry is now engaged in developing measures and guidelines that address operating reserves for primary frequency control and their interactions with operating reserves for secondary frequency control. There is currently active industry discussion regarding whether the systematically larger and predictable frequency excursions (documented by Martinez [2010]) pose a reliability concern, and, if so, whether modifications to the CPS1 and CPS2 standards are needed. For the past 5 years, the industry has been developing, testing, and refining a new performance standard called

[69] As discussed in Section 2.2, we know today that some generation owners prevent operation of the governors that provide primary frequency control actions by either disabling the governors or running at maximum output, while others rapidly override the operation of their governors through plant secondary controls that seek to restore plant output to pre-scheduled values within seconds.

the balancing authority ACE limit. The intent is to address ACE and frequency excursions of shorter durations. If adopted, the balancing authority ACE limit would replace CPS2.

Concern regarding the declining quality of frequency control in the interconnections has also led industry to focus on isolating reserves for primary frequency control as an element of operating reserves and elevating the importance of primary frequency control. NERC has tasked a Frequency Response Standard Drafting Team to develop a standard to assemble information needed to assess the reasons for declining frequency.[70] In spring 2009, after many years of study and discussion, the Western Electricity Coordinating Council (WECC) issued a white paper on frequency-responsive reserves, but then voted to terminate its activities to develop a standard on this topic (WECC 2009b). In fall 2009, NERC announced the formation of a Frequency Response Initiative (Electric Utility Week 2009; see also NERC 2010a and NERC 2010b).

At its March 2010 meeting, FERC set a compliance time frame for NERC to address directives contained in Order No. 693, issued in 2007, concerning frequency response.[71] The specific directive was to identify "the necessary amount of frequency response needed for Reliable Operation and methods of obtaining and measuring that frequency response is available."

## 4.2 Operational Integration of Wind is a Growing Concern for U.S. Transmission System Operators but is Not Yet Linked to Frequency Response

We interviewed power system operators of four large U.S. transmission systems with significant wind generation potential to gain insight into the operational issues they were then facing or expected to face related to integration of variable renewable generation and its impact on frequency response.[72] Staff at the Bonneville Power Administration (BPA), California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), and the Midwest Independent Transmission System Operator (MISO) generously shared their perspectives and concerns, answered our questions, reviewed our interview notes, and provided follow-up materials.

Integration of wind generation is a growing operational concern for the operators in each of the four transmission systems. CAISO's operational concerns also extend to solar generation (both photovoltaic and solar thermal). At current levels of renewable generation, all four system operators report that the operational issues related to integration have been manageable. Each, however, anticipates significant increases in variable renewable generation and is taking active steps to study and implement operational changes that may be required.

Current efforts seek to improve short-term wind forecasting and scheduling and, in some cases, create new market products or processes and protocols to improve short-term operational flexibility. All four operators continue to study the expected adequacy of their requirements for

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[70] See http://www.nerc.com/filez/standards/Frequency_Response.html

[71] Subsequently, an Order Granting Rehearing for Further Consideration and Scheduling Technical Conference was issued on May 13, 2010 at 131 FERC ¶ 61,136.

[72] The interviews were conducted during the summer of 2009.

regulation, load following, and generation imbalance. All expect future increases in these requirements resulting from the greater variability and volatility of increased wind generation.

Dealing with ramping of wind energy, especially when ramping is rapid and prolonged, has emerged as a significant operational issue. The primary concern is predicting the timing and duration of wind ramping events so that conventional resources can be scheduled and dispatched in a timely manner to meet rapidly changing net system loads during the ramping period. All four systems have either implemented or are considering procedures to increase control over wind generation output by either limiting permissible upward wind ramp rates or curtailing wind output. ERCOT, which on a percentage basis has the largest wind penetration of the four operators we interviewed, already has formal procedures in place that gives its operators this dispatch flexibility for wind. All four operators recognize, however, that downward wind ramps can never be controlled through contractual arrangements. Consequently, all four are also looking into ways to increase rapid access to conventional resources to help in managing these fast downward ramping events.

Due to the relatively small amount of interconnected wind generators, the frequency response impacts of variable renewable generation, as outlined in Section 3, have not yet emerged as a significant operational concern. None of the four system operators mentioned this topic explicitly in describing their current frequency control efforts.[73] [74]

## 4.3 Recent U.S. Renewable Integration Studies Have Not Focused on Frequency Response Impacts

Transmission operators have conducted a number of studies to address operating issues related to integration of variable renewable generation. The majority of studies have focused on estimating reserves for secondary frequency control to meet expected increases in requirements for regulation and load following. Only one of the wind integration studies we reviewed, discussed next, has focused on aspects of primary frequency control.

As part of a larger study on integration of variable renewable generation, CAISO conducted dynamic simulations of the frequency response of the Western Interconnection using a well-known, production-grade, dynamic simulation tool (CAISO 2007). CAISO also used the well-calibrated system model that WECC has developed and refined in recent years. The CAISO study found that the frequency response impacts from the increased amount of variable renewable generation required to meet California's policy objectives (at that time, 20 percent of California's expected 2020 electricity requirements) could be accommodated reliably. That is, CAISO found that the reserves of primary frequency control assumed to be available within WECC were adequate to arrest and stabilize the decline in system frequency following

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[73] Subsequent to the interview we conducted, CAISO staff note that they have recently commented to WECC on frequency response concerns related to increased wind generation. See http://www.wecc.biz/searchcenter/Pages/Results.aspx?k=Notification%20of%20Final%20Draft%20Criterion

[74] Subsequent to the interview we conducted, BPA staff suggested that long-term monitoring of wind plant performance with phasor measurement units or other devices is needed to understand the contribution of wind plants to frequency response during disturbances.

simultaneous loss of the two large generating units routinely considered in WECC planning studies.

The CAISO study did not, however, consider increases in variable renewable generation across the entire Western Interconnection (e.g., within BPA). The study is also not explicit on how integration of wind generation affected the dispatch of generating units providing primary frequency control, nor, consequently, how this dispatch might be affected during extreme conditions such as at times of high wind output, minimum system loads, and minimum reserve levels. In Section 5, we will extend the analysis conducted to date by CAISO, including use of the same tools and system models, to study the same loss of generation event during times of minimum system load considering both higher levels of wind generation on an interconnection-wide basis and a range of operating reserves.

The majority of studies of the operational issues associated with renewable generation integration focus on estimating increases in requirements for regulation and load following – i.e., secondary frequency control.[75] Table 4-1 summarizes selected findings on future regulation and load-following requirements from recent variable renewable generation operational integration studies. Notably, the studies all uniformly estimate significant increases in the requirements for secondary frequency control.

**Table 4-1. Selected Findings from Recent Wind Integration Studies on Expected Increases in Requirements for Regulation and Load Following**

| Area | Wind in Base Scenario (MW) | Highest Wind Scenario Studied (MW) | Regulation | Load Following |
|---|---|---|---|---|
| | | | Change in Requirements (%) | Change in Requirements (%) |
| **NYISO (GE 2005)** | 0 | 3,300 | 95% | 6% |
| **Minnesota (EnerNex 2006)** | 1,049 | 5,688 | 15% | 5% |
| **Avista (EnerNex 2007)** | 0 | 600 | Not studied | 123% |
| **CAISO (CAISO 2007)** | 2,648 | 6,688 | 92%/200% | 30%/24% |
| **ERCOT (GE 2008)** | 5,000 | 15,000 | 23%/21% | 20%/39% |
| **BPA (PNNL 2008)** | 2,700 | 6,300 | 233%/383% | 170%/47% |

Sources: (GE 2005, EnerNex 2006, EnerNex 2007, CAISO 2007, GE 2008, PNNL 2008)

These renewable integration studies are important because, as discussed previously, the adequacy of secondary frequency control reserves directly affects the adequacy of primary frequency control reserves. For the most part, the studies seek to ensure that secondary frequency control reserves are always capable of managing the increased variability in net system load caused by increased wind generation. Consequently, these studies do not focus on

[75] See, for example, PNNL (2008), CAISO (2007), GE (2005 and 2008), and EnerNex (2006 and 2007), among others provided on the Utility Wind Integration Group library website, http://www.uwig.org/opimpactsdocs.html.

primary frequency control, nor do they address the interaction between primary and secondary frequency control reserves. Section 6 of this report discusses this interaction directly and reviews in detail the insights from these prior studies that apply to understanding this topic.

### 4.4 International Experiences Offer Selected, Yet Important Insights into Frequency Response-related Issues Associated with Integrating Variable Renewable Generation in the U.S.

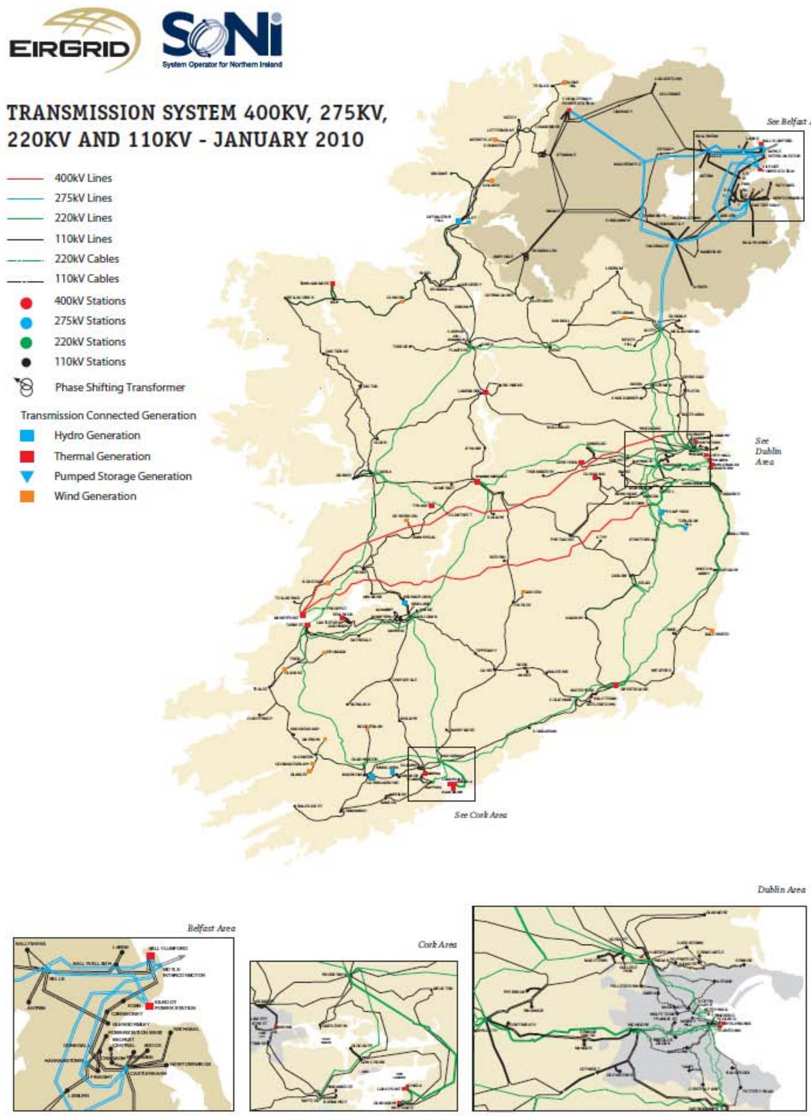
We reviewed international experience with frequency response impacts of variable renewable generation on power system reliability, particularly from three countries with significant amounts of wind energy on their electricity power systems: Denmark, Ireland, and Portugal. We find that these countries' interconnections and operating practices differ significantly from those in the U.S., yet their experiences offer selected, important insights regarding frequency response issues that are relevant to the U.S.

EirGrid is the Republic of Ireland system operator and the owner of the System Operator Northern Ireland. Together the two entities operate a single synchronous system on the island of Ireland. This is a small system (peak demand of 7 GW) with a large penetration of wind power (1.6 GW installed, providing approximately 10 percent of annual electricity requirements). It is virtually an electrical island, with a single 400-MW DC link to Great Britain. See Figure 4-4.

EirGrid (2009) conducted empirical studies of the frequency response of the Irish power system (Dudurych 2009). EirGrid's internal studies relate increased wind generation to the magnitude of frequency excursions following loss-of-generation events. These reports empirically confirm simulation studies by others on the relationship between lower system inertia and lower frequency nadir, which we discussed in Section 3.4.1.

In sharp contrast to the U.S. and continental Europe, yet consistent with its operation as essentially an electrical island, the Irish power system is operated with comparatively wide ranges of acceptable system frequency. Operating frequencies routinely range between +/- 200 mHz (around a base frequency of 50 Hz). In the U.S., the comparable range is nearly an order of magnitude narrower (e.g., between roughly +/- 20 to 30 mHz around a base frequency of 60 Hz [Martinez 2010]). Involuntary, under-frequency load shedding begins in Ireland at 49.1 Hz (below a base frequency of 50 Hz), while, as discussed in Section 3.3, in the U.S. it begins in some regions at 59.7 Hz (below a base frequency of 60 Hz).

It is inappropriate to suggest that the large interconnections of the U.S. could adopt similar frequency control practices. The large, interconnected power systems of the U.S. (and Europe) developed comparatively tighter ranges for acceptable system frequency to enable the entities within the interconnection to control power flows among themselves equitably, based on closely managing the balance between the loads they serve and the generation they procure. As discussed earlier in this section (and by Illian [2010]), the basic design of U.S. frequency control practices has been predicated on this requirement. Ireland, as noted, is essentially an electrical island; interchange with Great Britain is controlled directly as a result of the transmission technology employed (high voltage DC).



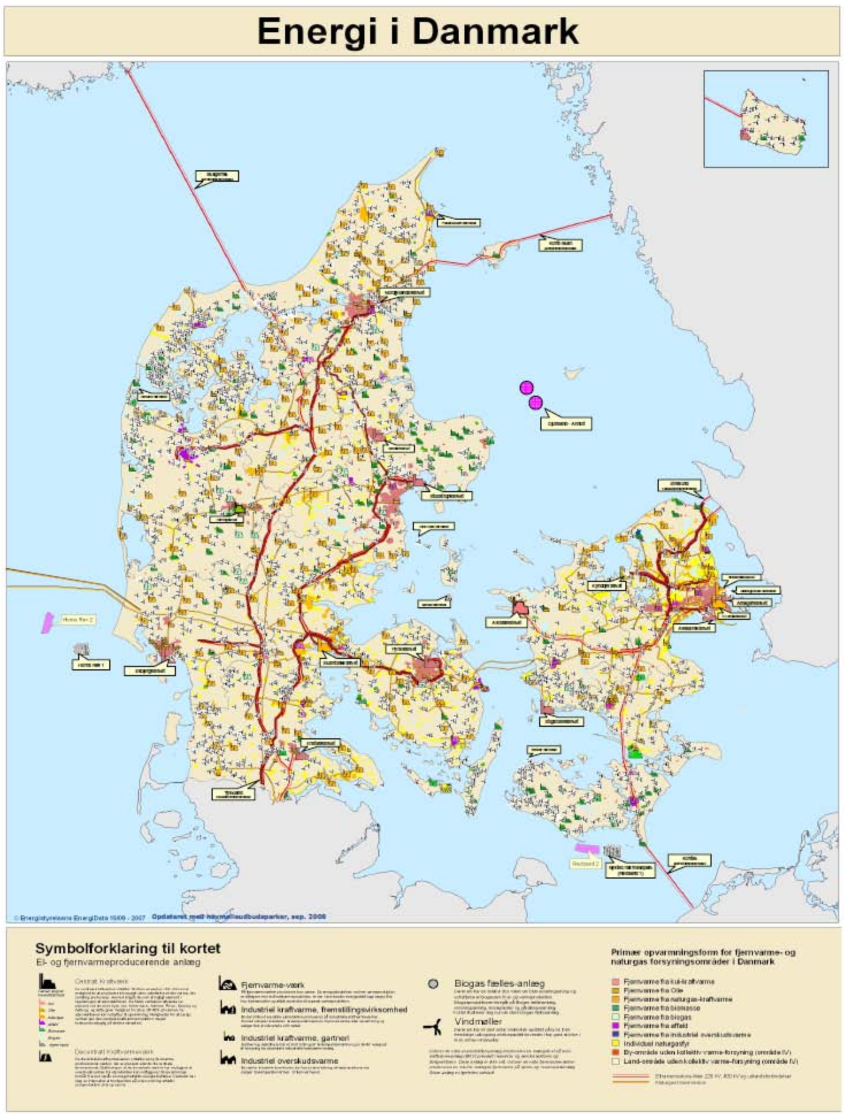

Source: http://www.eirgrid.com/media/All-Island%20Transmission%20Map%20%28January%202010%29.pdf

**Figure 4-4. EirGrid Transmission System**

It is, however, noteworthy that the Irish power system relies on a form of demand response for frequency control; this is a practice that we believe is relevant for the U.S. The first tier of under-frequency load shedding is not involuntary. It is comprised of customers on interruptible tariffs that compensate them in return for allowing their loads to be shed automatically at 49.3 Hz which is 0.2 Hz above its first set point of involuntary under-frequency load shedding involving firm loads.[76] This is a highly effective complement to generation reserves set aside for primary frequency control.

[76] The Texas Interconnection relies on a similar form of frequency-responsive demand response for this purpose and, as we discuss in Section 5.

EnerginetDK is the Danish System Operator. The Danish system is approximately the same size as the Irish system and has 3.5 GW of installed wind generation capacity, which generates electricity equivalent to about 20 percent of the system's electricity requirements. Eastern Denmark is part of the Nordic interconnection (90 GW total generating capacity with approximately 2.5 GW of wind capacity). Most of Denmark's wind generating capacity (2.7 GW) is located in western Denmark, which is part of the Continental Europe interconnection (640 GW total generating capacity, 45 GW of installed wind capacity). Interestingly, east and west Denmark have no transmission links that joins them to one another; west and east Denmark are each connected separately to the Continental Europe system (via a 550 MW DC link) and Nordic Systems (via links totaling 1.7 GW), respectively.[77] See Figure 4-5.




Source: http://www.ens.dk/da-DK/Info/TalOgKort/Energikort/Download_faerdige_kort/Documents/Energi%20i%20Danmark_plakat.pdf

**Figure 4-5. EnerginetDK Transmission System.**

[77] The Europe system is comparable in size to the Eastern Interconnection.

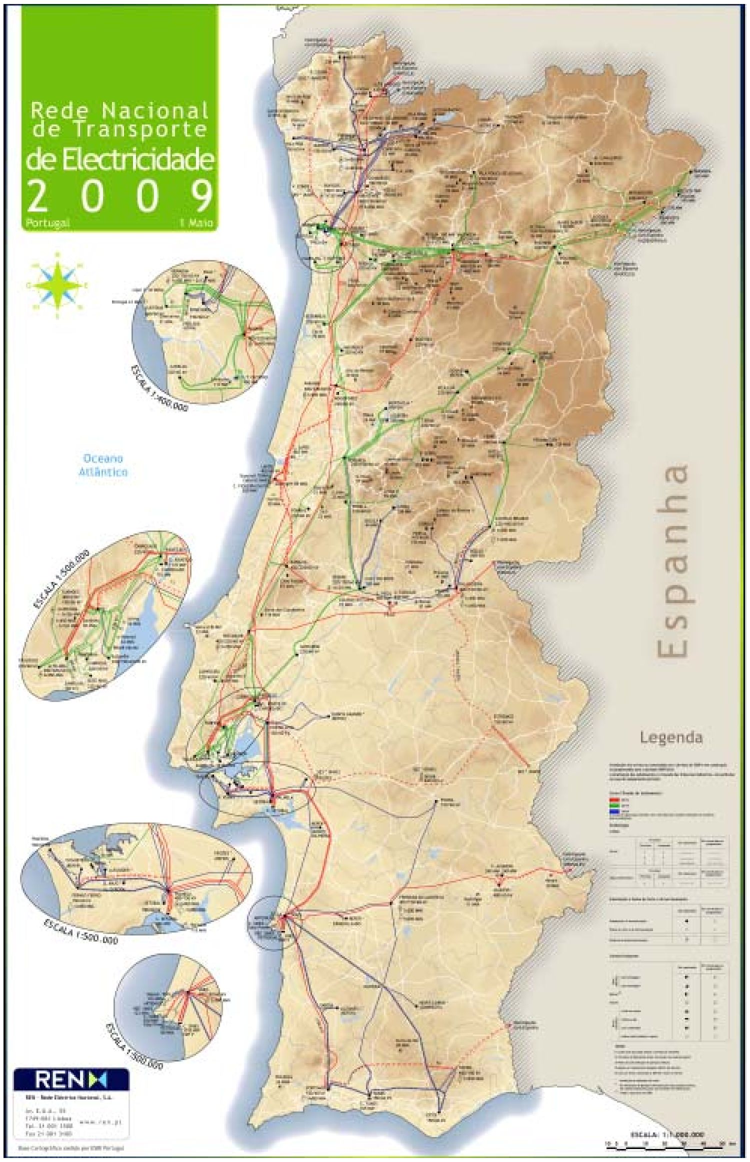
Thus, although there is significant wind electricity generation in Denmark, this amount of generation does not represent a significant proportion of the total electricity generated in either of the two major interconnections that each include a portion of Denmark. As a result, the frequency control and frequency response requirements associated with integration of Danish wind generation into these two very large and distinct interconnections are reported to be virtually nonexistent because these issues are addressed by the respective interconnections as a whole and the contribution of Danish wind generation is comparatively small. The main frequency control issue noted by Danish power system operators is related to trading changes on the hour, which is consistent with the findings of Martinez (2010) for the U.S., as reported earlier in Section 4.1 (UCTE Ad Hoc Group 2008) and is not a function of wind operations.

Management of primary frequency control within Continental Europe (the former Union for the Coordination of Transmission of Electricity) shares the same objective of tight frequency control as does the U.S. (and, as mentioned, the ranges are far narrower than those of island systems, such as Ireland). However, the means by which frequency control is achieved differs considerably from U.S. practices. The European operating guides are prescriptive in requiring a minimum level of primary frequency control from all generators (UCTE 2004). Primary frequency control performance is specified in terms of speed (fully activated within 15 seconds), magnitude (capacity head room that must always be available), and duration of response (sustained for up to 15 minutes or more).

Rede Eléctrica Nacional (REN) is the Portuguese system operator. The Portuguese system is approximately twice the size of the Irish system (15.7 GW capacity, 3.4 GW wind), and wind provides about 10 percent of its annual electricity requirements. It is part of the Continental European synchronous system. It shares the Iberian Peninsula with its larger neighbor, Spain (95 GW total generation capacity, 17 GW wind capacity). Together, they have very high levels of wind generation (15 percent of total annual electricity requirements). They are connected to the Continental European system via France (through links that can import up to 1.2 GW and export up to 0.6 GW). See Figure 4-6.

Experiences reported by REN are consistent with those reported by EnerginetDK. No frequency impacts have been observed on the Iberian Peninsula related to wind. Frequency deviations that have been observed are related to market activities that have created uneven transitions at the top of the trading hour. The reliability impact of wind generation of greatest concern has been when faults occur, because the majority of older wind turbines in use there are not equipped with low-voltage ride-through capability.

From this we can conclude that the frequency performance of an interconnection depends on the deliverable resources within the entire interconnection. While there can be areas with concentrations of wind resources such as the Iberian Peninsula or Denmark, it is the mix of resources in the entire interconnection that will determine performance.




Source: http://www.ren.pt/vPT/Electricidade/Transporte/Documents/Mapa%20RNT%202009.jpg

**Figure 4-6. Rede Electrica Nacional Transmission System**

## 4.5 Published Literature on Integration of Variable Renewable Generation Has Begun to Examine Some Impacts on Frequency Response

Recent publications have begun to document the frequency response implications of the very low amounts of inertia provided by wind generation and to discuss ways to increase the contribution of wind turbines to system inertia. This final subsection briefly reviews some of these publications.

In 2009, the North American Electric Reliability Council issued a special report, “Accommodating High Levels of Variable Generation,” that touched briefly on frequency control (NERC 2009c). The report discusses the control capabilities of wind turbine generators, including frequency control and power management. The discussions cover the inertia-related characteristics of the four major types of wind turbine generators, and describe the possibilities for equipping variable sources to provide governing and participate in frequency regulation. The report also discusses power system operational issues related to management of secondary frequency control. The report, however, does not discuss interconnection-wide impacts of increased variable renewable generation on overall requirements for reserves for primary frequency control or the considerations that must be taken into account in ensuring that these reserves will always be adequate.[78]

University researchers at the Electricity Research Centre in Ireland have used academic-grade analysis tools to study the impact of wind generation on lowering the inertia of a simplified power system representative of Ireland's (Lalor et al. 2005, Doherty et al. 2010). They substantiate the theoretical relationships discussed in Section 3.4.1, namely, that a power system with wind generation will have lower inertia than a power system without wind generation for a given amount of total generation. Lower system inertia will increase the initial rate of frequency decline following loss of generation, so primary frequency control must be increased to ensure reliability. They also build on earlier published work exploring opportunities to modify wind turbine controls to increase their contribution to system inertia and provide a form of primary frequency control.

In the U.S., university researchers coordinated through the Power Systems Engineering Research Center (PSERC) have used commercially available dynamic simulation tools and system models and data made available by the industry to study the frequency response of the Eastern Interconnection with intermediate penetration levels of wind generation (Vittal et al. 2009). They find that frequency response impacts of a power system containing significant amounts of wind generation for severe, yet credible frequency excursion events can be managed without loss of customer load (i.e., frequency decline can be arrested above the set points for under-frequency load shedding). The study also examines opportunities for wind turbines to increase their contribution to system inertia and provide a form of primary frequency control.

However as we discuss in Section 5, the system models and data currently available from industry for studying the frequency response of the Eastern Interconnection have not been able to reproduce the recorded frequency performance of that interconnection following a recent loss-of-generation event. Instead, they predict a much more robust frequency response than the actual response that was recorded when the event took place. Consequently, it is premature to use results from the PSERC study to draw conclusions about the adequacy of primary frequency control reserves within the Eastern Interconnection with or without increased variable renewable generation.[79]

[78] The Task Force continues to meet and is pursuing follow-up activities identified in the special report. http://www.nerc.com/filez/ivgtf.html

[79] Consistent with this caveat, the PSERC study does not suggest that its findings are representative of the actual frequency response of the Eastern Interconnection.

### 4.6 Summary

The declining quality of frequency control in the U.S. interconnections is currently a significant reliability concern. It is widely understood that the operational integration of variable renewable generation is not related to and has not been a cause or contributor to the decline observed over the past decade. System operators report that the operational issues related to renewable integration have been manageable. They also report that they do not currently view frequency-response-related reliability impacts of variable renewable generation as a significant operational concern. However, as noted previously, all are reviewing potential impacts.

Recent studies of renewables integration within the U.S. have focused on increased requirements for secondary frequency control (regulation and load following), but only to a limited extent if at all on requirements for primary frequency control. International experiences, in particular from countries with large wind penetrations, provide selected, yet important insights for the U.S. Still, those countries' interconnections and operating practices differ from those in the U.S. The academic literature has begun to document frequency response implications of the very low amounts of inertia provided by current wind generation technologies, but no studies of these impacts have been performed using validated models of U.S. interconnections.

Taken together with the list of potential impacts of increased variable renewable generation on frequency response (in Section 3), these findings confirm the timeliness of the present study to examine these impacts through the simulation studies and analysis that are presented in Sections 5 and 6, respectively, using the frequency response metrics developed in Section 2.

# 5. Dynamic Simulation Studies to Assess the Frequency-Response-based Reliability Impacts from Integration of Variable Renewable Generation

This section presents findings on potential frequency-response-related impacts of increased variable renewable wind generation on the three U.S. Interconnections by 2012. The assessment is based on analysis conducted using commercially available, production-grade dynamic simulation tools and industry-developed system models, which include the amount of wind generation capacity the planners in each interconnection expect in 2012. This section first clarifies that the system models were used "as provided." The models are used to illustrate how the frequency response metrics developed in this study can be used to guide and assess the reliable integration of variable renewable generation. This section next introduces elements of the study that were common to all three interconnections. Finally, it presents findings specific to each interconnection.

The discussions in this section draw from a technical report commissioned for this study, which is published separately (Mackin et al. 2010).

## 5.1 Industry-Developed Generation and Transmission Assumptions in the System Models Provided for This Study Established the Amount of Wind Generation that Was Studied

This study focuses on industry-developed system models developed for 2012 because it is near enough in the future that we can be reasonably confident about the accuracy of the assumptions made regarding the transmission and generation infrastructure that would be in place to support integration of wind generation. Table 5-1 summarizes the amount of wind generation capacity that is expected within each interconnection in 2012 as reflected in the system models provided by industry for this study. The amounts of wind generation contained in these models is capable of meeting approximately 1, 3, and 13 percent of the total expected generation in 2012 for the Eastern, Western, and Texas Interconnections, respectively. See Text Box.

The decision to rely on these models is important for two reasons: First, the explicit representation of the supporting generation and transmission infrastructure provided by industry-developed system models is essential for using commercially available, production-grade simulation tools to conduct realistic assessments of the frequency response of the interconnections. Second, as was also noted in Section 1, LBNL was not tasked by FERC to assess the type, amount, cost, and timing of transmission required to integrate increased amounts of variable renewable generation.

Consistent with this recognition, we did not use the system models developed by industry to study scenarios involving increases in wind generation capacity beyond the amounts currently represented in the system models provided to us. Instead, we focused our efforts on using these simulation tools and system models along with the frequency response metrics developed in Section 2 to illustrate the considerations or conditions that must be met in order to reliably integrate the wind generation expected within each interconnection in 2012.

**Expressing Wind Capacity as a Percentage of Total Electricity Generation Within Each Interconnection**

The simulations conducted for this study examine wind generation at a single point in time within a year and for this reason the amount of wind generation is expressed in terms of wind generation capacity or gigawatts (GW). To gain a perspective on how much this amount of wind generation capacity might contribute toward meeting the total electricity requirements of an interconnection requires information on the capacity factor of the wind generators. Capacity factor is the ratio of the average output of a generator over the course of a year to its peak output (or capacity). Wind generation capacity factors vary from less than 30% to as much as 40%. For illustrative purposes, the table below assumes a capacity factor of 35% for all wind generators. With this assumption, the table estimates how much wind energy would be produced by the amount of wind capacity that is expected in 2012. This assumed amount of wind generation is then expressed as a percent of the total amount of electricity delivered within each interconnection in 2012.

| | 2012 Wind Capacity (Source: Industry-Provided System Models) GW | 2012 Wind Energy (Assume Wind Capacity Factor = 35%) TWh | 2012 Net Energy for Load (Source: NERC LTRA 2008) TWh | Wind Generation as Percentage of Net Energy for Load |
|---|---|---|---|---|
| Eastern Interconnection | 10.5[1] | 32 | 3233 | ~1% |
| Western Interconnection | 9.0 | 28 | 804 | 3% |
| ERCOT | 14.4 | 44 | 339 | 13% |

[1] 2008 wind capacity taken from AWEA (2009).

## 5.2 Overview of Simulations Conducted to Study Frequency-response-based Reliability Impacts from Integration of Variable Renewable Generation by 2012

The objective of the simulation studies of each interconnection was to assess the effects of different amounts of wind generation capacity on frequency behavior of each interconnection following a sudden loss of large amounts of conventional generation. The scenarios created to study these effects considered an operating circumstance in which system load was at or close to its minimum and wind generation was expected to be at its maximum. These scenarios are expected to occur almost every night and represent times when primary frequency control reserves may be at a minimum. The event studied was the sudden loss of the largest amount of conventional generation consistent with events actually recorded within each interconnection. The simulations calculated the impact of this event on interconnection frequency for different levels of wind generation output. In addition to varying the amount of wind generation, the simulations varied the amount of operating reserves between a high level representative of current operating practices and a low level representative of minimum requirements. We first compared the frequency nadir predicted by the simulation to the highest set point for under-frequency load shedding within each interconnection and then used the primary frequency response metrics (developed in Section 2) to examine the delivery of primary frequency control actions at and around the time of the frequency nadir.[80] See Table 5-1.

**Table 5-1. Study Conditions Assumed for 2012 Frequency Response Simulation Analysis**

| | 2012 Minimum or Light System Load (GW) | Size of Wind Generation Examined (GW) | Size of Loss of Generation Event Studied (GW) | Highest Under-Frequency Load-Shedding Set Point (Hz) |
|---|---|---|---|---|
| Western Interconnection | 80 | 9 | 2,800 | 59.5 |
| Texas Interconnection | 34 | 14.4 | 2,450 | 59.3 |
| Eastern Interconnection | 309 | 10.5[81] | 4,500 | 59.7 |

The studies of each interconnection share the following important features:

First, all simulations were conducted using the same commercially available, production-grade simulation tools that are currently used by industry: the General Electric (GE) Positive Sequence Load Flow (PSLF) for the Western Interconnection and the Siemens Power Technologies International Power System Simulator for Engineering (PSS/E) for the Texas and Eastern Interconnections (GE 2009, Siemens 2009). The tools contain detailed representations of the operation of generators and their automatic controls, the transmission system (including the operation of under-frequency and other load-shedding relays), and the behavior of loads. These tools are routinely used by the industry to study the dynamic performance of the interconnections in response to system events that result in major perturbations of voltage, frequency, and flows of power. These studies are performed routinely and on an ongoing basis to assess future system capabilities and to establish system operating limits, which in turn guide generation dispatch, transmission flows, and voltage profiles.

A typical dynamic simulation usually covers about 20 seconds following an event. As discussed in Section 2, a successful response to events such as the loss of generation requires immediate, automatic actions largely from generation resources (as well as the innate change in load, called load-damping, see Footnote 31). Twenty seconds is about the longest period of time over which the effectiveness of these actions, acting alone (i.e., without the influences of other changes to the power system, including slower control actions), can be modeled and assessed. These simulation tools were developed specifically to study the effects of these actions on system frequency, voltages, and real and reactive power flows, among other rapid phenomena affecting the reliability of the power system.

Second, planners within each interconnection provided us with the interconnection-wide system models they have developed to conduct these types of studies. We requested and received a system model that had been developed to represent light-load conditions expected in 2012. Each

[80] See NERC (2007) and NERC (2008a). Note that, at the time this report was prepared, the Florida Reliability Coordinating Council was in the process of revising its UFLS set-point from 59.82 Hz to 59.7 Hz.

[81] Due to inconsistencies in how entities modeled wind generation in the ERAG model, the amount of generation was estimated from other sources and compared to the ERAG model.

was helpful and forthcoming in answering the technical questions that we asked, including in some cases review of simulation results, to ensure that we use their models properly.[82]

As noted above, we took the amount, type, and location of generation (including wind generation) as well as the topology and properties of the transmission system represented in the system models as given. Therefore, no wind (or conventional) generation capacity and no transmission capacity was added to the system models above the levels contained in the models.

Third, the loss of generation event studied is based on an actual event involving the loss of a large amount of generation within each interconnection. We chose to study these events because they have, in fact, been observed; they are not hypothetical. As noted in Section 2, this procedure is consistent with that outlined by NERC in determining interconnection frequency limits.[83]

Fourth, the project team endeavored to follow accepted modeling practices in conducting the simulations. When the cases were prepared for simulation, generation redispatch and operating reserves levels were established separately for each balancing authority within the interconnection to maintain power flows among balancing authorities at levels established in the interconnections' system models that were provided to us. In conducting the simulations, the team made minor adjustments to ensure that voltage limits defined for the cases were observed.

Before turning to the findings from our simulations, we emphasize a basic limitation of the use of present-day dynamic simulation tools to study the impacts of variable renewable generation on frequency response. These tools cannot be used to study the fourth potential impact of variable renewable generation on frequency response that was outlined in Section 3.4.4, which is the potential erosion of primary frequency control reserves after secondary control reserves have been fully deployed. The interactions between primary and secondary frequency control reserves can take place over many minutes of operation (including and especially during the time *prior* to a loss-of-generation event). Practically speaking, today's dynamic simulation tools and system modeling practices are intended primarily to study system performance over about 20 to 40 seconds of operation *following* a discrete event (in this case, involving a sudden, large imbalance between load and generation).

The significance of this limitation for the simulation-based findings presented in this section is that all findings must be prefaced with the following caveat: "*Subject to the adequacy of secondary frequency control reserves, we find the following with respect to the adequacy of primary frequency control reserves…*" This caveat is important because, as we will discuss further in Section 6, we have concluded that the interaction between primary and secondary frequency control reserves is extremely important, not well understood, and in need of additional study. We emphasize this caveat by introducing each of our findings as "initial findings.

[82] The study authors, alone, however, bear sole responsibility for technical adequacy of the analysis methods and the accuracy of the study results pertaining to frequency response.

[83] "[The number of allowable contingencies] should be a minimum two contingencies, so that the Interconnection is always at least one contingency away from an Under Frequency Load Shed, but may be greater based on a statistical analysis of contingency probabilities" (NERC 2003).

### 5.3 Initial Frequency Response Findings for the Western Interconnection

The Western Interconnection covers nearly 1.8 million square miles and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 contiguous western U.S. states in between. The Western Electricity Reliability Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.[84]

Following the 1996 West Coast blackouts, WECC members devoted considerable effort to updating, validating, and calibrating the WECC dynamic system models. A principal focus of WECC's initial efforts was calibration of the generation plant governor models for primary frequency control action to match actual recorded performance and explicit representation of plant secondary control actions that can override primary frequency control actions (Pereira et al. 2003).

The goal of WECC's ongoing efforts is to ensure that the models can be used to accurately reproduce the recorded frequency and voltage performance of the interconnection following major loss-of-generation events. Demonstrating this capability is essential for establishing confidence in the model's use in setting reliability-based operating limits. For example, the tool is currently used seasonally by WECC to set operating transfer capabilities, which are the operating limits that have been put in place to limit flows of power across aggregations of transmission inter-ties connecting the balancing authorities within the interconnection to one another.

We obtained the WECC system model for winter 2012-13 light-load conditions and used the GE PSLF tool to conduct simulation studies of the Western Interconnection.[85] The system model is developed and maintained by the WECC Planning Coordination Committee for use in transmission planning studies. This model is available to all qualified signatories of the WECC agreements (WECC 2009a).

We first reduced system loads in equal proportions for each balancing authority within the interconnection to lower total system load from the 111 GW in the light-load case provided to us down to 80 GW. 80 GW corresponds to minimum load conditions that has been observed in the interconnection.

We also reduced conventional generation to serve this lower system load. The output from conventional generation was lowered based on economic merit order assuming wind has zero dispatch costs. This process involved decommitting (i.e., turning off a generator and taking it off line) some sources of generation and lowering the output from other sources in order of decreasing marginal production cost (i.e., by first decommitting generation from or lowering the output from the generators that are most expensive to operate). Merit order redispatch was

[84]See http://www.wecc.biz/About/Pages/default.aspx

[85] We obtained the WECC 2012-13 Light Winter case. See Mackin (2010) for additional details of this system model.

constrained, however, to ensure that each balancing authority continued to hold adequate operating reserves, as required by WECC reliability standards.

We studied the frequency response of the interconnection following the simultaneous loss of two large nuclear generating units located in the southwestern portion of the interconnection. This is one of the largest two-unit loss of generation events that has been experienced by the interconnection. The combined maximum output of these two baseload units is 2,900 MW. However, when these units are lost, 100 MW of internal station use load is also dropped, so the net loss of generation to the interconnection is 2,800 MW.

Review of the under-frequency load-shedding schemes currently in place within the interconnection led us to identify 59.5 Hz as the highest frequency at which firm customer loads would be shed, so we selected this value to establish the frequency nadir threshold for our study.

The wind generation scenarios we modeled were developed by adjusting the amount of wind energy produced at the locations that are already represented in the winter 2012-13 light-load case. We adopted this approach because the interconnections facilities for all 9 GW of wind generation are already fully represented in the WECC system model for 2012.

The total installed capacity of wind represented in the case is approximately 9 GW. On an annual basis, assuming a 35-percent capacity factor, this amount of installed wind generation capacity is capable of producing approximately three percent of the total energy generated within the interconnection. Since wind generation output will vary, we examined three wind generation output scenarios corresponding to 1 GW, 4 GW, and 9 GW to determine the impact of increasing wind generation on the existing systems. All changes in wind output were represented through equal proportional increases in output at each wind generation site up to the total installed capacity.

As the amount of wind generation increased, generation from non-wind sources was re-dispatched downward following the same economic merit-order procedure described previously. The downward dispatch was conducted separately for each balancing area. This procedure leads to essentially no change in the amount of power transferred among the balancing authorities within the interconnection.

We chose to model all wind turbines using the new generic wind turbine generator model for Type 3 wind turbines, which are the predominant type of turbines in the interconnections queues in the WECC region for installation by 2012. This model has been recently certified by WECC for use in GE PSLF (Ellis et al. 2009). See Text Box.

We examined two approaches for managing system operating reserves during the minimum system load conditions that occur during the middle of the night. The two approaches result in a high and low level of primary frequency control reserves and thus establish the bounds for our study results. The levels of primary frequency control are independent of the type of resources in the system models for 2012. For instance, if wind generation with primary frequency control were widely available and in the models, they would have been deployed.

**Wind Turbine Models and Frequency Response**

The simulation studies of the Western Interconnection were conducted by modeling all wind generation as type 3 wind turbines using the generic type 3 wind turbine model that has been approved for use by the WECC in interconnection power system studies.[1]

The decision to model all wind generation as type 3 wind turbines was motivated by the following considerations. First, we could not use the WECC-approved type 1 and 2 wind turbine models because they caused numerical instabilities within the simulation tools in our preliminary simulations involving the sudden loss of a large amount of conventional generation. Second, review of the interconnection queue indicated that the vast majority of wind turbines that are slated for installation in the Western Interconnection by 2012 will be type 3 wind turbines; we found no type 4 wind turbines in the interconnection queue with a 2012 in-service date.

Recently, wind turbine manufacturers have announced wind turbines that are capable of providing some inertia as well as primary frequency control. We are, however, unaware of any current installations of wind turbines with these capabilities and had no information on the extent to which these capabilities have been specified for wind generation that is currently in the Western Interconnection queue. The current WECC-approved type 3 wind turbine does not currently include these capabilities and so we were not able to consider them in our simulation studies, but recommend this topic for future studies.

[1] The wind turbine models contained in the system models provided by industry for the Eastern and the Texas Interconnection consistent of proprietary models.

In the first approach, we followed typical WECC operating practice (that is also followed in other interconnections), which involves minimizing the amount of generation that is de-committed at night. Many generating units are not shut down and then restarted on a daily basis for economic reasons. They are kept running and are on line at night but dispatched at very low levels of output. This practice assures that they are available to ramp up the following day to meet mid-day loads. We call these cases “High Reserves.” In the High Reserves cases, approximately 22 GW of generation capacity in excess of 80 GW of the generation capacity required to meet load is kept on line.

For the second approach, we examined the effect of holding operating reserves based on a close interpretation of current WECC standards regarding the minimum amount of spinning reserve that must be carried by balancing authorities within the interconnection at all times. WECC’s contingency reserve standards require that balancing authorities hold synchronized generation capacity on line equal to approximately 4.5 percent of load at all times (WECC 2008). Implementing this standard in the simulation study involves decommitting some generation units and lowering the output from other generation units (relative to the High Reserves case). As before, we followed a procedure based on economic merit order (separately for each balancing authority) in an attempt to achieve this target. We call these cases “Low Reserves.” In the Low Reserves cases, approximately 6 GW of generation capacity in excess of 80 GW of the generation capacity required to meet load is kept on line.[86]

[86] See Mackin (2010) for a detailed discussion of how application of WECC’s standard separately for each balancing authority leads to this level of operating reserves.

Figure 5-1 presents simulation results for the three levels of wind generation output corresponding to 1 GW, 4 GW, and 9 GW for the High Reserves case. Each case shows the evolution of system frequency over the first 19 seconds following the sudden loss of 2,800 MW of generation from two large generating plants in the southwestern portion of the interconnection.

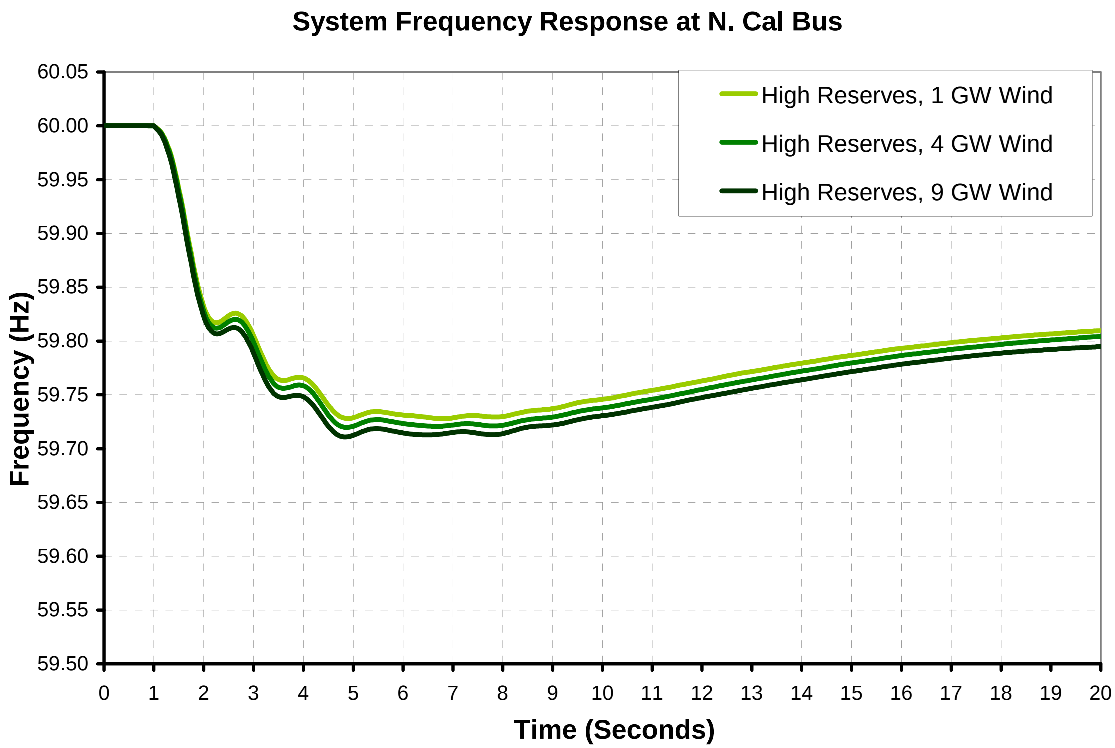



**Figure 5-1. Simulated Western Interconnection System Frequency Over the First 19 Seconds Following the Sudden Loss of the 2,800 MW of Generation for the High Reserves Case**

The first point to note is that, for all three levels of wind generation, the reserves of primary frequency control contained within the 22 GW of total operating reserves are adequate to ensure continued uninterrupted delivery of electricity to customers, despite the sudden loss of nearly four percent of the generation serving load. That is, the frequency nadir remains approximately 200 mHz above the highest set point for under-frequency load shedding for all three levels of wind generation.

The second point to note is that, while the effect is quite modest, the reduction in system inertia caused by increased wind generation is noticeable. It is not noticeable in the initial rate of frequency decline, which is virtually identical for all three levels of wind generation. However, it is noticeable in very slightly, yet progressively lower, frequency nadirs that are recorded as the level of wind generation increases. Bear in mind that, at 9 GW, wind generation represents more than 10 percent of the generation serving load.

Figure 5-2 presents simulation results for the three levels of wind generation output (1 GW, 4 GW, and 9 GW) for the Low Reserves case. The format of presentation is identical to that in Figure 5-1.

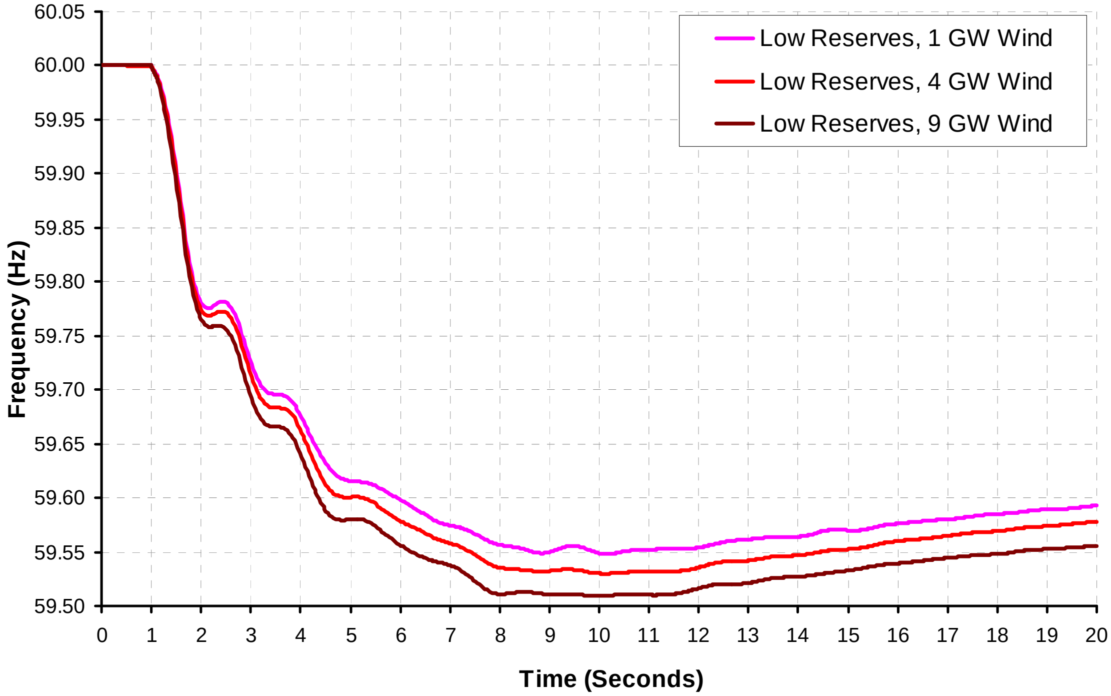



**Figure 5-2. Simulated Western Interconnection System Frequency Over the First 19 Seconds Following the Sudden Loss of the 2,800 MW Generation for the Low Reserves Cases**

The first point to note is that the risks to the interconnection as measured by the margin between the lowest frequency and UFLS, appear to be much greater with the lower reserve level than in the High Reserves case, independent of wind output levels. While the frequency nadir never crosses below the under-frequency load-shedding set point for all three levels of wind generation, the frequency nadir is significantly closer to this UFLS set point than in the High Reserves case (less than 50 mHz).

The second point to note is that the effect of the reduction in system inertia due to wind generation is more apparent. The initial rates of frequency decline are again virtually identical for all three levels of wind generation. However, while the primary response is essentially identical (Figure 5-3), the frequency nadirs are noticeably distinct from one another (compared to the High Reserves case); they are, again, progressively lower as the level of wind generation increases. As identified in section 3, a small increase in primary frequency control can offset the change in inertia at these levels of wind penetration.

Figure 5-3 documents the underlying physical basis for the differences in frequency response from the two levels of operating reserves. Figure 5-3 shows the evolution of primary frequency control actions (i.e., primary frequency response) for all six cases. The power delivered by primary frequency control in all three High Reserves cases is significantly greater than that delivered in all three Low Reserves cases at every moment in time over the first 19 seconds following the sudden loss of generation. In addition, for a given level of reserves, the power delivered by primary frequency control is virtually identical for all three levels of wind generation.

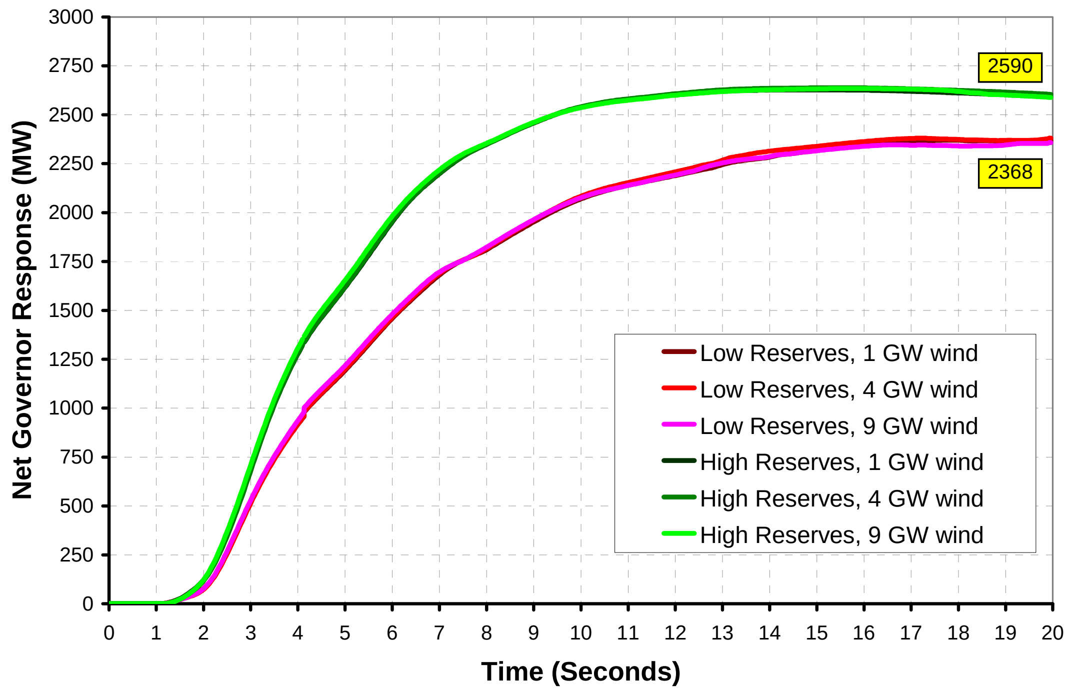



**Figure 5-3. The Power Delivered by Primary Frequency Control Actions via Generator Governors in the Low and High Reserves Cases**

Figure 5-3 also illustrates the principal finding from our simulations of the Western Interconnection and the motivation for the use of the primary frequency response metrics we developed in Section 2. The frequency response of the Western Interconnection depends foremost on the amount of primary frequency control reserves contained in the operating reserves we assumed, not on the levels of wind generation we studied. It depends on power delivered by primary frequency control actions over the initial seconds following the loss of generation, which are the quantities that are measured by primary frequency response metric. As has been discussed earlier however, care must be taken to address both the loss of system inertia and the potential displacement of resources with integrating large amounts of variable renewable generation into the system. In this regard, the simulation results for the Western Interconnection are fully consistent with the theoretical relationships first discussed in Sections 2 and 3, and reinforce the appropriateness of using these metrics to determine the adequacy of the primary frequency control reserves assumed in the simulations.

Table 5-2 summarizes the results from all six simulations, including the normalized system inertia, frequency nadir, nadir-based frequency response, and primary frequency response metrics. Given the inertia of the Western Interconnection, which leads to formation of the frequency nadir approximately 5 to 8 seconds after the sudden loss of generation, the primary frequency response at 4, 9, and 19 seconds are presented.

**Table 5-2. Summary of Dynamic Simulation Results for the Western Interconnection**

| Reserves | Wind Generation (GW) | Normalized System Inertia (sec) | Frequency Nadir (Hz) | Nadir-Based Frequency Response (MW/0.1 Hz) | Primary Frequency Response at 4 seconds (MW) | Primary Frequency Response at 9 seconds (MW) | Primary Frequency Response at 19 seconds (MW) |
|---|---|---|---|---|---|---|---|
| High Reserves | 1 | 4.8 | 59.73 | 1037 | 1,629 | 2,541 | 2,590 |
| | 4 | 4.7 | 59.72 | 1000 | 1,633 | 2,562 | 2,604 |
| | 9 | 4.5 | 59.71 | 966 | 1,665 | 2,537 | 2,589 |
| Low Reserves | 1 | 4.6 | 59.55 | 622 | 1,202 | 2,072 | 2,368 |
| | 4 | 4.5 | 59.53 | 596 | 1,208 | 2,086 | 2,380 |
| | 9 | 4.2 | 59.51 | 571 | 1,227 | 2,078 | 2,357 |

For each of the two levels of reserves assumed, the primary frequency response values at each point in time are virtually identical for all three levels of wind generation. For the High Reserves case, the primary frequency control reserves are adequate to withstand the sudden loss of 2,800 MW of generation for all three levels of wind generation. For the Low Reserves case, the primary frequency control reserves are also adequate to arrest frequency but they are closer to deployment of under-frequency load shedding.

As noted above, it was not possible to study the frequency response of the Western Interconnection with higher levels of wind generation capacity using the WECC system model because the system model WECC developed contains only 9 GW of wind generation along with the associated transmission required to deliver this amount of wind generation.[87]

In conclusion, our simulation study of the Western Interconnection confirms that the interconnection can be reliably operated with the levels of wind generation expected by 2012, provided the interconnection is operated with the numbers and types of conventional generation that result in historic levels of primary frequency control reserves.[88] We recognize that the number and types of generation that are dispatched can and will change over time and that the

[87] A preliminary effort was made to increase the total amount of wind generation in the interconnection. We sought to increase wind generation by following the order in which wind generation projects stand in the queue for transmission interconnection. This effort was halted when it was found that adding wind generation in this manner quickly exceeds the capabilities of the current transmission interfaces between balancing authorities where the wind generation would be built and the balancing authorities where the generation would have to be delivered. For example, we found one instance in which the amount of wind generation quickly exceeded the total load of the balancing authority containing this generation.

[88] According to WECC staff, current and historic levels of primary frequency control are above those simulated in the low reserve case studied in this report during low load time frames.

guidance provided by the metrics developed in this report will assist in assuring reliable operation. This finding, however, is subject to the caveat that secondary frequency control reserves are always adequate, which we will examine separately in Section 6.

### 5.4 Initial Frequency Response Findings for the Texas Interconnection

The Electric Reliability Council of Texas (ERCOT) is the independent system operator for the Texas Interconnection, which contains 40,000 miles of transmission lines and more than 550 generation units.[89] Currently, the Texas Interconnection provides electricity to 22 million Texas customers, representing 85 percent of the state's electrical load and 75 percent of Texas' land area. The interconnection is asynchronous with the Western and Eastern Interconnections; thus, it is an independent interconnection.

For our study of the Texas Interconnection, we followed the same basic procedures as for our study of the Western Interconnection. Texas Interconnection planners provided a summer 2012 light-load system model of the Texas Interconnection for use in our study.[90] Like their counterparts in the Western Interconnection, Texas Interconnection planners have also calibrated their system models to ensure accuracy (ERCOT 2005). In their 2012 light-load system model, generation is dispatched to serve 34 GW of total system load.

The Texas Interconnection's minimum system load is, in fact, closer to 26 GW. Therefore, we first attempted to reduce loads in equal proportions to this minimum, as we did in our study of the Western Interconnection. We were, however, unable to redispatch the conventional generation contained in the light-load system model to serve this lower load in the high-wind-generation scenarios we considered.[91] Consequently, we conducted all our simulation studies of the Texas Interconnection using the loads and generation dispatch contained in the 34-GW light-load system model.

The total installed wind capacity in 2012 light-load system model is 14.4 GW. Assuming a 35-percent capacity factor, this amount of installed wind capacity would produce approximately 13 percent of expected electricity requirements of the Texas Interconnection in 2012. As we did for the Western Interconnection, we examined three wind generation output scenarios corresponding to 0 GW, 7.2 GW, and 14.4 GW.

It is critical to note that the 2012 light-load system model assumes completion of the transmission projects that have been planned for the Competitive Renewable Energy Zones (ERCOT 2006). If, however, these projects are not completed by 2012, it would not be possible to accommodate all 14.4 GW of wind generation that is represented in the 2012 light-load system

[89] See http://www.ercot.com/about/

[90] The system model we obtained is known as the ERCOT 2012 Summer Off-peak Base Case, which was developed by ERCOT for the study titled "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas." http://www.ercot.com/news/presentations/2007/index

[91] As discussed in greater detail in Mackin (2010), in the time available to complete our study, we were not able to undertake the adjustments required to maintain system voltages at acceptable levels with the voltage control capabilities available from conventional generators for the high wind scenarios involving minimum operating reserves.

model. As of summer 2009, the level of wind generation on the Texas Interconnection was approximately 8 GW, yet, according to ERCOT, wind generation output was constrained to much lower levels (roughly 4.5 GW) due to insufficient transmission.

As the amount of wind generation is increased in the simulation, generation from non-wind sources was re-dispatched downward. We did not follow a strict economic merit order procedure for the redispatch, as we did for the Western Interconnection. To focus on the role of generator governors in providing primary frequency control, we decommitted generators based both on economic merit order and on the speed of their governor response; we sought to keep the generators with the fastest responding governors on line and ensure that they were dispatched below their maximum output.

To model the interactions between wind generators and the interconnection, we relied on the wind turbine models contained in the system model provided to the ERCOT project team. These models are proprietary and specific to individual wind farms as specified by the developers. As such, we did not make any assumptions as to the location, type or capabilities of the wind resources, but relied on the models provided by ERCOT for the resources they expect to be in the system plan for 2012.

We used the simulation tool to study the frequency response of the interconnection following the simultaneous loss of two large nuclear generating units. This event is the largest loss of generation event that has been experienced by the interconnection. The combined net output of these two baseload units is 2,450 MW.

The Texas Interconnection's under-frequency load-shedding program starts at 59.3 Hz. Five percent of the interconnection's load is shed at this frequency (ERCOT 2009). As we discuss below, the interconnection also has a program in which customers receive capacity payments in return for allowing their loads to be curtailed automatically at a much higher system-frequency set point than the involuntary under-frequency load shedding set point. This program is distinct from the interconnection's formal under-frequency load shedding program.

As we did for our study of the Western Interconnection, we examined two approaches for managing system operating reserves during light-load conditions. Under the first approach, we examined a policy that maintains operating reserves consistent with current operating practices, which leads to reserves well in excess of the amounts required by the interconnection's standards for responsive reserves.[92] This case is called High Reserves. For the second approach, we examined a close, but not exact, interpretation of current interconnection standards for responsive reserves. This case is called Low Reserves.

The Texas Interconnection's responsive reserve standards require that synchronized generation capacity (and frequency-responsive demand) equal to 2,300 MW must be held at all times.[93] The interconnection permits up to 50 percent of this requirement to be supplied by customers

[92] Responsive reserves is the term used within the Texas Interconnection to refer to the class of contingency reserves that is called spinning reserves in Section 2.

[93] See Section 2.5.2 in ERCOT (2009).

who are compensated in return for allowing their load to be curtailed automatically at predetermined frequency set points. The program is called Load acting as a Resource (LaaR). The frequency set point for the LaaR program is 59.7 Hz. As noted, this set point is considerably higher than that of the interconnection's involuntary under-frequency load-shedding program at 59.3Hz. The customers and generators that provide responsive reserves to the interconnection are selected through a competitive market process, and both are compensated monetarily at the same rate. The interconnection routinely acquires the maximum amount of responsive reserves permitted by its standards through the LaaR program.

For the High Reserves cases, we replicated a typical operating practice within the Texas Interconnection (and other interconnections), which limits the amount of generation that is decommitted at night. As noted for the Western Interconnection study, many generating units are not shut down and restarted on a daily basis for economic reasons. Thus, at night, they are kept on line but dispatched at very low output so that they are available to ramp up the following day to meet mid-day loads. In the High Reserves cases, more than 8 GW of generation capacity (and 1150 MW of LaaR) is kept on line in excess of the 34 GW of generation capacity required to meet load.

For the Low Reserves cases, we decommitted some generation units (i.e., took them off line) and lowered the output from other generation units. We followed a procedure based on economic merit order (roughly, decommitting and lowering dispatch of the most expensive units first) in an effort to achieve the lower operating reserve target. In addition, we also sought to decommit units with slower governors before decommitting units with faster governors. In the Low Reserves cases, 3 GW of generation capacity is kept on line (in addition to the LaaR) in excess of the 34 GW of generation capacity that is required to meet load. Notably, according to ERCOT staff, Texas Interconnection standards require that all generators operate with their governors in service, which means that all generation dispatched below maximum output is capable of providing primary frequency control actions following the sudden loss of generation.

Figure 5-4 and Table 5-3 present the simulation results for the three levels of wind generation (0 GW, 7.2 GW, and 14.4 GW) for both the High and Low Reserves case. For all three levels of wind generation, under both the High and Low Reserves cases, frequency is arrested well above the highest under-frequency load shed set point (59.3 Hz). This is particularly significant because the amount of conventional generation lost, as a percent of total generation is nearly twice that considered in our study of the Western Interconnection (more than 7 percent for the Texas Interconnection, compared to about 4 percent for the Western Interconnection).

The primary reason for this more robust performance can be seen by comparing Figure 5-5 for the Texas Interconnection with Figure 5-3 for the Western Interconnection. The simulations for the Texas Interconnection indicate significantly faster delivery of primary frequency control. As discussed in Section 2, other things being equal, faster delivery of primary frequency control means that the same frequency nadir would be recorded for either a larger percent loss of generation or a lower normalized system inertia compared to an interconnection with slower delivery of primary frequency control. We did not explore the reasons for faster delivery of primary frequency control in the Texas Interconnection compared to the Western Interconnection.

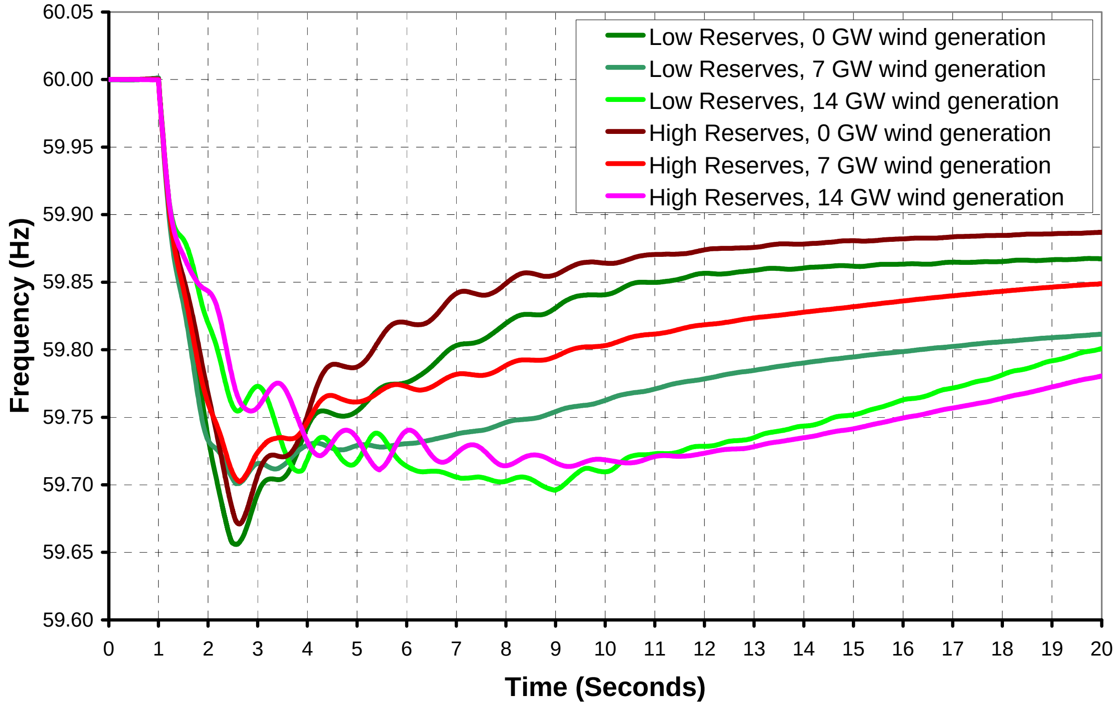



**Figure 5-4. Simulated Texas Interconnection System Frequency Over the First 19 Seconds Following the Sudden Loss of the 2,450 MW of Generation for the High and Low Reserves Cases**

As discussed in Section 2, frequency declines at a much more rapid rate in the Texas Interconnection than it does in the other two interconnections because the amount of generation lost is larger in proportion to the size of the interconnection. Consequently, in contrast to the two initial primary frequency response metrics used for the Western Interconnection (at 4 and 9 seconds), for the Texas Interconnection, primary frequency response metrics at shorter intervals (at 2 and 4 seconds) are presented in Table 5-3. Both total primary frequency response and the portion of primary frequency response contributed by governors are presented. The difference between the two primary frequency response values represents the contribution of LaaR.

The simulations for the Texas Interconnection reinforce the principal findings from our study of the Western Interconnection: the rapid delivery of power via primary frequency control actions is more important than the amount of wind generation in determining the frequency nadir. The effect of increased wind generation in lowering system inertia, while measurable is not significant, because it is addressed by the amount and speed of primary frequency control reserves and the addition of LaaRs.

It is useful to examine aspects of the simulations to understand how the LaaR program, combined with our efforts to decommit and redispatch generation in order to maintain the fastest governors affected primary frequency control.

**Table 5-3. Summary of Dynamic Simulation Results for the Texas Interconnection**

| Reserves | Wind Generation (GW) | Normalized System Inertia (sec) | Frequency Nadir (Hz) | Nadir-Based Frequency Response (MW/0.1 Hz) | Primary Frequency Response at 2 seconds [governor response] (MW) | Primary Frequency Response at 4 seconds [governor response] (MW) | Primary Frequency Response at 19 seconds [governor response] (MW) |
|---|---|---|---|---|---|---|---|
| High Reserves | 0 | 4.5 | 59.67 | 742 | 2,403 [1,398] | 2,574 [1,596] | 2,371 [1,389] |
| | 7.2 | 3.9 | 59.70 | 817 | 1,967 [1,493] | 2,032 [1,418] | 2,150 [1,538] |
| | 14.4 | 3.4 | 59.71 | 845 | 1,482 [1,291] | 1,779 [1,535] | 2,134 [1,606] |
| Low Reserves | 0 | 4.4 | 59.66 | 721 | 2,294 [1,290] | 2,446 [1,464] | 2,311 [1,329] |
| | 7.2 | 3.5 | 59.70 | 817 | 1,862 [1,340] | 1,951 [1,263] | 2,141 [1,458] |
| | 14.4 | 2.9 | 59.70 | 817 | 1,335 [1,273] | 1,677 [1,104] | 2,075 [1,083] |

Figure 5-5 illustrates the important role of LaaR in rapidly taking load off the system to supplement generator governor response in arresting and stabilizing frequency. Generator governors respond immediately to the decline in frequency following the loss of generation. LaaR does not contribute to frequency response until the frequency set point at which it is engaged is crossed. When the set point is crossed, however, LaaR response is immediate and, in fact, the rate of delivery of the effect (i.e., the removal of load) is much faster than the rate of delivery of power from generator governors. When we inspect the timing of LaaR's deployment and the frequency nadir, we see LaaR's response has a major role in arresting frequency decline.

Table 5-3 indicates that the frequency nadir is actually lowest for the scenarios involving no wind generation, under both High and Low Reserves. This is contrary to our simulations of the Western Interconnection in which we found that frequency nadir was lower as the level of wind generation increased. The explanation lies with the procedures we developed to increase the effectiveness of primary frequency control actions delivered by generator governors. As discussed above, as the level of wind generation was increased, in addition to consideration of economic merit, we decommited and redispatched units taking into account the speed of the governors on generators. This preserved reserves by preventing the displacement of the generators in the dispatch stack. In fact, despite having lower total conventional generation on line (in order to accommodate increased levels of wind generation), our approach for re-dispatching generation in the simulation resulted in a fleet of generation that provided very fast governing response.

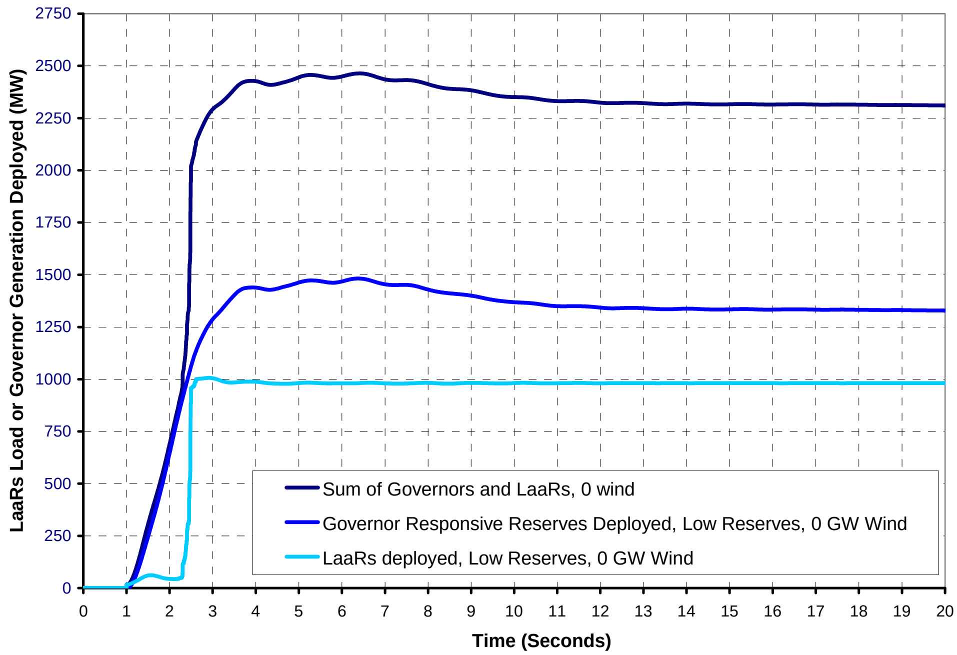



**Figure 5-5. Primary Frequency Control Actions Delivered via Generator Governors and Withdrawn by Load Acting as a Resource for the Low Reserves Scenario with No (0 GW) of Wind Generation for the Texas Interconnection**

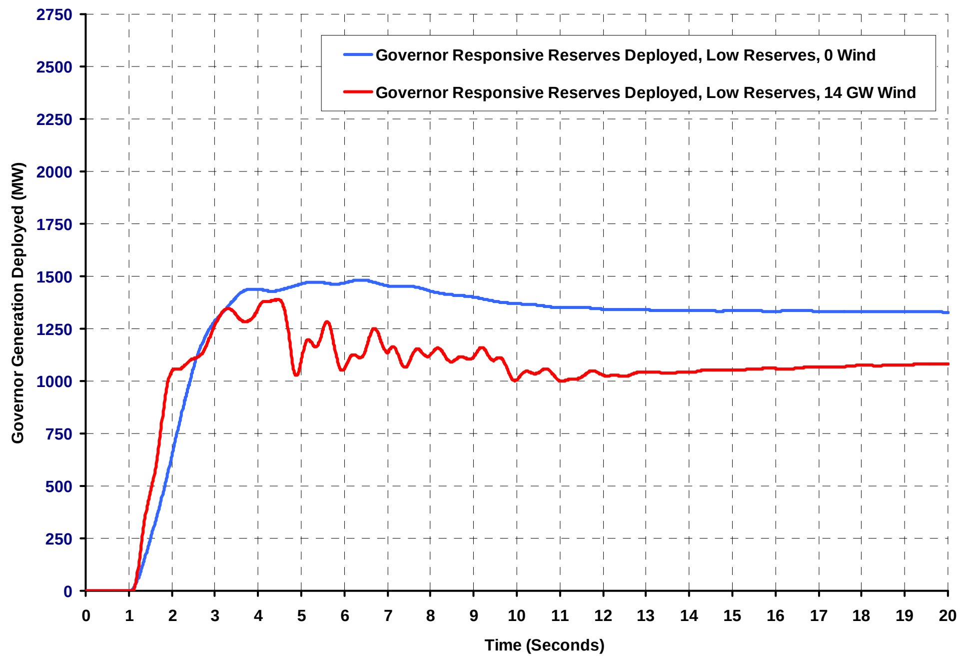



**Figure 5-6. Comparison of Primary Frequency Control Actions Delivered via Generator Governors for the Low Reserves Scenario with No (0 GW) and High (14.4 GW) of Wind Generation for the Texas Interconnection**

Figure 5-6 illustrates the result of our re-dispatch approach. The generator governors contained in the high wind scenario delivery primary frequency response faster than those contained in the no wind scenario. The effect of faster delivery of power is to decrease (i.e., slow down) the rate of frequency decline. When combined with the effect of LaaR, the result is a slightly higher frequency nadir.

This result is a significant finding and a further confirmation of the physical relationships discussed in Sections 2 and 3. It suggests that focused attention on the quality of primary frequency control actions, provided by generator governors and, in the Texas Interconnection, frequency-responsive demand response, can readily off-set the effects of increased wind generation on system inertia and the generator dispatch stack. This is particularly notable because in our simulations of the high wind generation scenario, wind comprises more than 40 percent of the total generation serving load.

In conclusion, our simulation study of the Texas Interconnection confirms that the interconnection can be reliably operated with the levels of wind generation expected by 2012, provided the interconnection is operated with adequate levels of primary frequency control reserves. This finding, however, is subject to the caveat that the transmission, planned through the CREZ process, which is required to deliver this amount of wind generation, is completed by 2012. This finding is also subject to the caveat that secondary frequency control reserves are adequate, which we will examine separately in Section 6.

### 5.5 Initial Frequency Response Findings for the Eastern Interconnection

The Eastern Interconnection covers approximately 3.5 million square miles and includes the provinces of Saskatchewan, Manitoba, Ontario, Quebec and the Maritimes provinces in Canada, and all or portions of the contiguous 39 U.S. states (and the District of Columbia) east of the Western Interconnection. Six regional entities are responsible for coordinating and promoting bulk electric system reliability in the Eastern Interconnection: the Florida Reliability Coordinating Council, the Midwest Reliability Organization, the Northeast Power Coordinating Council, Inc., the ReliabilityFirst Corporation, the SERC Reliability Corporation, and the Southwest Power Pool, Inc.[94]

To study the Eastern Interconnection's frequency behavior following the sudden loss of generation with different amounts of wind generation and operating reserves, we obtained a 2009 light-load system model developed by the Eastern Interconnection Reliability Assessment Group (ERAG) and Multiregional Modeling Working Group (MMWG).[95] [96] ERAG's purpose is to augment the reliability of the bulk-power system in the Eastern Interconnection through periodic reviews of generation and transmission expansion programs and forecasted system conditions. Among other things, ERAG periodically prepares an interconnection-wide model based on individual system models submitted by its members.

[94] See http://www.nerc.com/page.php?cid=1|9|119

[95] See http://www.erag.info/

[96] The system model we obtained is known as the 2009 Light-Load case from the 2008 ERAG-MMWG series.

Notably, according to ERAG, it does not conduct independent verification or calibration of the interconnection-wide model using actual events. Consequently, we first sought to compare the simulated frequency behavior of the Eastern Interconnection following a recent large generation-loss event using the ERAG-MMWG system model against the recorded performance of the interconnection following this event.

We used the Siemens-PTI's PSSE simulation tool to conduct power flow and dynamic simulation studies with the ERAG-MMWG system model (Siemens 2009). System planners in the interconnection routinely use this tool for reliability studies.

The generation-loss event we selected is one that occurred recently. The event involved a complex series of line and generator outages in which a total of approximately 4,500 MW of generation was lost in less than 10 seconds. Due to its size and the number of reliability regions affected, it has been the subject of considerable analysis by the industry, including but not limited to the frequency response of the interconnection. Fortunately, detailed monitoring was in place, which captured the frequency behavior of the interconnection following the event.

We found that we could not use the ERAG-MMWG system model to reproduce the recorded frequency behavior of the interconnection to the event we selected for this initial study. The simulation predicted significantly greater frequency response than was, in fact, recorded by monitoring equipment.[97] See Figure 5-7 and Figure 5-8.

Because the ERAG-MMWG system model is the only interconnection-wide system model that is recognized and currently in use by transmission planners in the Eastern Interconnection, we chose not to pursue the analysis on this basis any further. We concluded that it would not be meaningful to conduct frequency response studies of this interconnection without better-calibrated system models.

In lieu of a formal simulation-based study, we used information on the observed frequency response of the interconnections presented by Martinez 2010, and insights on the technical underpinnings of frequency control presented by Undrill (2010) to develop an approximate analytical representation of the frequency response of the Eastern Interconnection. We first validated our approach using the simulation-based findings for the Western Interconnection. Applying our approach along with the frequency response metrics developed in Section 2 suggests that the Eastern Interconnection should be able to be operated reliably with the levels of wind generation output expected in 2012. We caution the reader, however, that formal studies, relying on commercially available dynamic simulation tools and fully calibrated system models should be conducted to identify the factors that must be involved in ensuring reliable operation of the Eastern Interconnection as the generation mix changes, including higher levels of variable renewable generation.[98]

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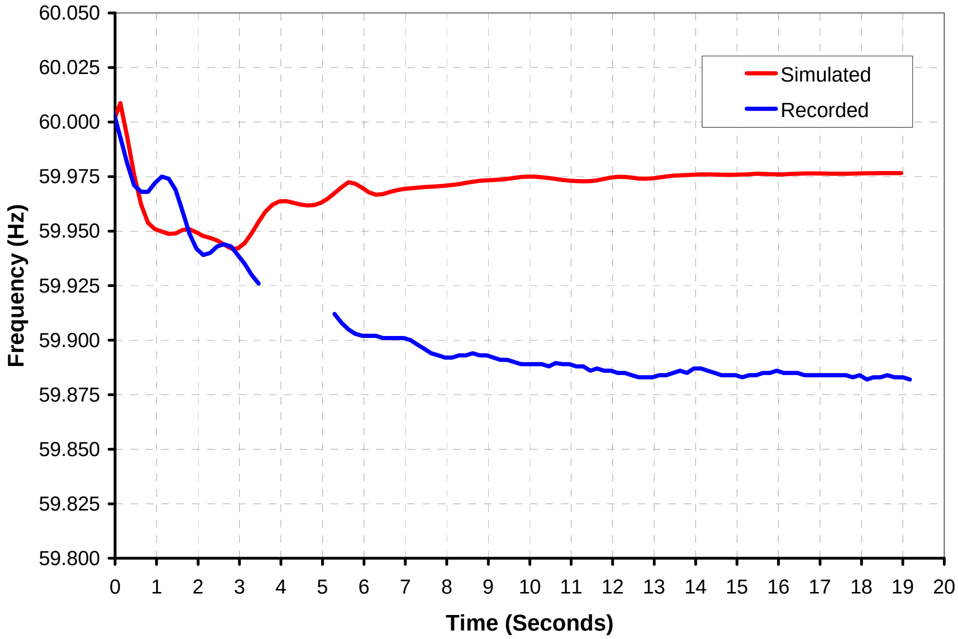
[97] This finding is not unique to our study. See, for example, NPCC (2008).

[98] For example, the wind generation capacity that we expected to be in service in 2012 and was included in the 2009 light-load system model provided by ERAG is capable of generating approximately 1% of the total annual electricity requirements of the Eastern Interconnection. This amount of capacity, however, is significantly less than




Note: There is a gap in the record of monitored data collected between approximately 3 and 5 seconds.

**Figure 5-7. Frequency of the Eastern Interconnection Over the First 19 Seconds Following the Loss of 4,500 MW of Generation – A Comparison of Recorded Data with Results from a Simulation of the Event**

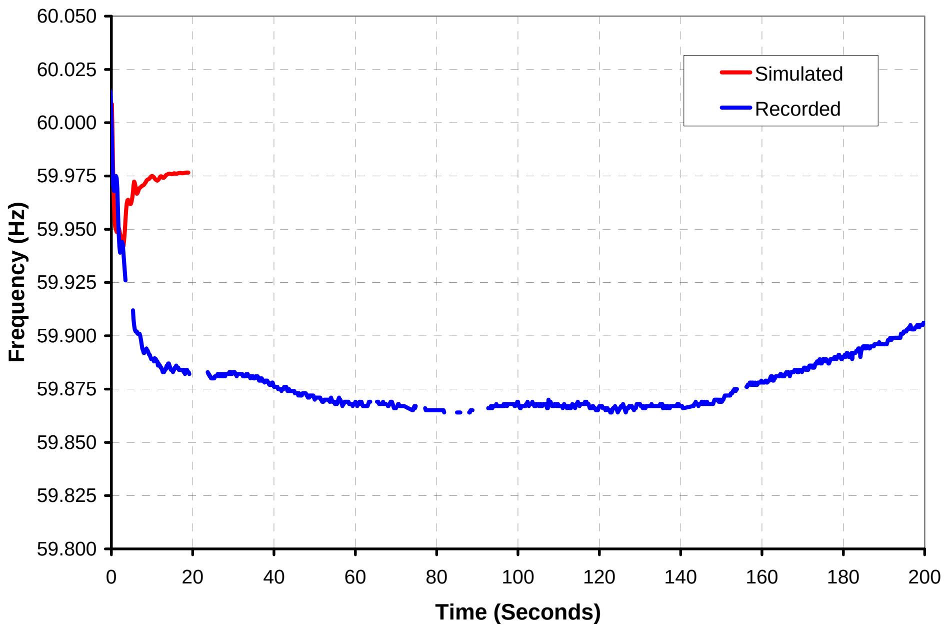



**Figure 5-8. Frequency of the Eastern Interconnection Over the First 199 Seconds Following the Loss of 4,500 MW of Generation – A Comparison of Recorded Data with Results from a Simulation of the Event**

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the total amount of wind generation capacity contained in the interconnection queues within the Eastern Interconnection.

## 5.6 Summary

We studied the frequency response of each of the three U.S. interconnections using the same dynamic simulation tools and system models used by the industry. These tools and models were developed to assist the industry in analyzing, among other things, the effectiveness of operating reserves in stabilizing power system frequency following the sudden loss of large conventional generation. These tools and models are used routinely by the industry to anticipate and address emerging reliability issues that they expect to face.

We preface our findings by noting that we were only able to study the generation (including wind) and transmission system that was represented in the system models developed and provided to us by industry. In addition, as discussed next in Section 6, the tools and models available today cannot be used to predict the fourth potential impact of variable renewable generation on frequency response (the erosion of primary frequency control reserves as secondary frequency control reserves are fully deployed). Hence the findings from our simulation studies must be further prefaced with the following caveat: *"Subject to the adequacy of secondary frequency control reserves, we find the following with respect to the adequacy of primary frequency control reserves…"*

For the Western Interconnection, assuming operating reserve conditions that are representative of current practices and that are used in daily operations (which are higher than the minimum levels that are allowable under current operating procedures), our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected by 2012. The system model we studied included 9 GW of installed wind generation capacity, which based on an assumed 35% capacity factor and NERC's estimate of electricity demand in 2012 could supply approximately 3 percent of the interconnection's expected electricity requirements in 2012. We were not able to study higher levels of wind generation capacity (consistent with the amounts and locations suggested by current interconnection queues for years after 2012) because the transmission system represented in the model provided for our study could not accommodate these higher levels of wind generation capacity without additions or upgrades.

However, we also find that there could be risks to reliability under certain operating conditions involving times of minimum system load, high levels of wind generation, and with operating reserves near the minimum that is allowable under current operating procedures and standards. We note that, according to staff at the Western Electricity Coordinating Council, these operating reserve conditions are rarely observed in daily operations. Still, because these conditions are permissible under current operating procedures and standards, they are a cause for concern, which we address in our recommendations in Section 7.

For the Texas Interconnection, assuming operating reserve conditions that reflect the lower range of the current operating practices, our simulation studies confirm that the interconnection can be reliably operated with the amount of wind generation and supporting transmission expected in 2012. The system model we studied included 14.4 GW of installed wind generation capacity which, based on an assumed capacity factor of 35% and NERC's estimates of electricity demand in 2012 could supply approximately 13 percent of the interconnection's expected electricity requirements in 2012. Notably, the results depend on the completion of significant portions of the new transmission that has been planned through the Competitive Renewable Energy Zone process.

Our study of the Texas Interconnection also confirms the effectiveness of the interconnection's reliance on a specialized form of demand response to control frequency following the sudden loss of generation. The interconnection's "Load acting as a Resource" program provides for customers to activate controls that automatically curtail selected loads whenever low-frequency conditions are sensed on the interconnection. Our simulation studies find that this program, whose principles may also be applicable within the Western and Eastern Interconnections, is an effective complement to the primary frequency control reserves currently provided by generating units. We address expanding the supply of sources of primary frequency control reserves, including this specialized form of demand response, in our recommendations in Section 7.

For the levels studied, a principal finding from our simulations of the Western and Texas Interconnection is that the rapid delivery of power via primary frequency control is more important than the amount of wind generation in determining the frequency nadir. The effect of increased wind generation in lowering system inertia is not significant compared to the effects of primary frequency control actions. The simulations also suggest that focused attention on the quality of primary frequency control actions, provided by generator governors and, in the Texas Interconnection, frequency-responsive demand response, can readily off-set the effects of increased wind generation on system inertia.

We were not able to conduct simulation studies of increased levels of variable renewable generation in the Eastern Interconnection. We found that, using the system model that was provided to us by industry, we could not reproduce the frequency response of the Eastern Interconnection to a recent recorded event involving the sudden loss of a large amount of generation. The simulation results predict that the frequency response of the interconnection was much more robust than the actual frequency response that has been observed based on measurements of real events. We concluded that it would not be meaningful to conduct a simulation-based study of the Eastern Interconnection with higher levels of wind generation without system models that are better calibrated to reproduce the actual performance of the interconnection.

In lieu of a formal simulation-based study, we used information on the observed frequency response of the interconnections, and insights on the technical underpinnings of frequency control to develop an approximate analytical representation of the frequency response of the Eastern Interconnection. Applying our approach along with the frequency response metrics developed in this report suggests that the Eastern Interconnection should be able to be operated reliably with the levels of wind generation output expected in 2012, which, assuming a 35% capacity factor, represents approximately 1% of the total expected electricity requirements of the interconnection in 2012.

# 6. The Reliability Impacts of Integrating Variable Renewable Generation on the Interaction between Primary and Secondary Frequency Control Reserves

This section describes how variable renewable generation affects the interaction between primary and secondary frequency control reserves. Study of this interaction is affected by several factors, including, the absence of commercially available simulation tools that can realistically model the interactions between these two types of reserves (which ranges over time frames of several seconds to tens of minutes), the limited and short historical records available on extreme wind ramping events and the inescapable role of human judgment in managing the resources that are required for primary and secondary frequency control during operations. These considerations represent important caveats for the initial findings presented in Section 5. Throughout these discussions, we apply the frequency response metrics developed in Section 2 and as explained in Section 3 to guide future efforts to better understand and identify actions to address these impacts.

The discussions in this section draw from two technical reports commissioned for this study that are published separately (Undrill 2010, Coughlin and Eto 2010).

## 6.1 The Adequacy of Primary Frequency Control Reserves Depends on the Adequacy of Secondary Frequency Control Reserves

In Section 3, we described the fourth potential impact of variable renewable generation on reliability as the requirement for operating reserves in addition to those set aside for primary frequency control. We briefly restate the main points from that discussion to lay the groundwork for the discussions that follow in this section.

With increasing incorporation of variable renewable generation, variations in net system load will be larger and less predictable than in the past. Studies of the operational impacts of variable renewable generation all find that the amount of regulation and load following (i.e., secondary frequency control) required in the future to manage the increased variability (and decreased predictability) of net system load will be significantly greater than that currently required. See Section 4.

The variability in net system load introduced by renewable generation is less predictable than that of customer loads alone, which follow a well-understood diurnal pattern. If secondary frequency control reserves (i.e., regulation and load following) that are required to manage predicted variability in net system load are under-forecast, under-procured, or not deployed in a timely manner, they may at times be unable to maintain frequency within narrow bounds around the scheduled value.

When this happens, primary frequency control reserves will act automatically to oppose further changes in frequency. As a result, the remaining reserves for primary frequency control may become depleted and incapable of arresting and stabilizing frequency following the sudden loss of generation. In the extreme, if the reserves for both primary and secondary frequency control have been fully utilized, there will be no operating margin left to respond to any further increase in load, which would cause an immediate (and unopposed) decline in frequency and potentially a wide-spread blackout.

Thus, it is imperative to maintain adequate secondary frequency control reserves for regulation and load following during normal operations. Doing so "protects" or "preserves" primary frequency control reserves so that they can always be available to respond promptly and decisively to arrest rapidly declining frequency following a sudden imbalance between load and generation.

Undrill (2010) discusses these interactions and why they are important for reliability and how they are affected by variable renewable generation. A critical example in Undrill's study (not discussed earlier in Section 3) illustrates the importance of operator judgment in the minute-to-minute scheduling of the dispatch of supplementary resources in anticipation of rapid and extended ramps that might result from extreme changes in wind generation output. The example shows how a decision to start up off-line generation just a few minutes late could have severe negative consequences for frequency. The example clarifies the importance of on-line resources with maneuvering capability (i.e., head room) compared to quick-start, off-line resources. Once primary frequency control reserves have been exhausted, frequency can become unstable long before the quickest-starting, off-line resources can be brought on line.

### 6.2 Recent Wind Integration Studies Do Not Provide Information Needed to Assess Interactions Between Primary and Secondary Frequency Control Reserves

In Section 4, we reviewed recent wind operational integration studies. Although many studies have focused on estimating increased requirements for secondary frequency control reserves (regulation and load following), we observed that the studies have, by and large, not focused on frequency response. Here, we expand on that initial review by discussing two aspects of recent studies that can and should be given greater attention in the future because these aspects are critical to assessing the interaction between primary and secondary control reserves.

By design, most integration studies have focused on estimating future requirements for regulation and load following for a single balancing area. As discussed in Section 4, the studies follow a common approach that involves subtracting an estimate of wind output variability from expected total system load to create the net system load that must be met by non-wind resources. Following this process, the amount of regulation and load following required to manage the now greater variability in net system load is estimated.

The estimation procedures preclude consideration of the interaction between primary and secondary frequency control reserves when they are based on an assumption that all variability can and will be managed by secondary frequency control reserves. This assumption is sometimes expressed by assuming Area Control Error (ACE) will be managed to a target value (for example, zero).[99] This is a laudable objective, especially in view of the importance for reliability of ensuring that secondary frequency control reserves are always adequate.

The studies that make these estimates represent the current state of the art. For the most part, they provide reasonable estimates for the increases in regulation and load following that will be

[99] If the ACE is zero or never beyond some magnitude, this indicates that the secondary control will not be depleted at any time.

required in the future. However, because their focus lies in using this information to estimate operating cost implications for accommodating increased wind generation, they rarely discuss issues relevant to frequency response and the potential for adverse impacts on reliability. There are two specific areas where we recommend improvements to inform future reliability studies that explicitly consider the interactions between primary and secondary frequency control:

First, future studies should be explicit in describing the criteria used to determine the adequacy of secondary frequency control reserves and should report requirements consistent with these criteria. Reporting how often, under what conditions, and to what degree regulation and load following are inadequate (e.g., ACE not equal to zero) is critical to understanding when and how primary frequency control reserves may be drawn upon in augmenting secondary frequency control reserves.

Some studies refer to NERC CPS requirements as the criteria used to determine adequacy but then do not report either the CPS scores targeted or achieved through the analysis. GE (2007) is exemplary in this respect because it identifies a quantitative target for the amount of net system load variability that is met (98.8 percent). Still, this report does not provide information on the instances that make up the 1.2 percent of the time when the estimated variability in net system load is not met (nor, consequently, does the report address implications regarding primary frequency control reserves during these periods). Future studies might then consider the operating cost implications of holding greater or lower amounts of reserves for secondary frequency control based on achieving different levels of frequency performance using metrics such as CPS1 or CPS2.[100]

Second, future studies should pay increased attention to extreme wind ramping events. These events place the greatest demands on secondary frequency control reserves. Here, it is especially important for future studies to be explicit in stating and testing the modeling assumptions that underlie estimates of the magnitude and likelihood of these events.

The majority of variable renewable generation integration studies rely on model-based (not empirically based) interpolations to estimate the variability of wind generation over periods of less than 1 hour. Yet, the current installed base of wind generation is modest compared to projections for the future, and the historical records on actual wind generation output are very short. We cannot say, for example, what a one-in-10-year extreme wind ramping event might look like for wind distributed over broad geographic areas because, among other reasons, we do not have more than 3 years of wind data available for many sites.

To examine this issue, Coughlin and Eto (2010) obtained high-time-resolution wind and system load information from several large transmission system operators to examine the actual variability of wind generation and compare it to a modeling assumption that is routinely made in recent wind generation integration studies. They find that the assumption that the distribution of changes in wind output can be approximated by a Gaussian or normal distribution is not supported by data on actual wind output. Relative to a Gaussian distribution, the actual distribution of wind output is actually narrower for small changes in output (i.e., smaller changes

[100] If the CPS requirements are set appropriately, it indicates that the secondary control will not be depleted at any time.

are less frequent) but is broader in the tails (bigger changes are more frequent). Although there are too few historical data available to support definitive statements regarding the true shape of the distribution, the conclusion that the true distribution is not Gaussian is consistent across the different regions and system sizes examined.

These findings have two implications for studies that rely on a Gaussian approximation to estimate increased requirements for regulation and load following. First, requirements for the amounts of regulation and load following needed to manage smaller changes in net system load are likely to be overestimated. That is, changes of this size occur less frequently than is predicted using a Gaussian approximation. Second, requirements for the amount of regulation and load following needed to manage large changes in net system load are likely to be underestimated. That is, changes of this size occur more frequently than is predicted using a Gaussian approximation.

The data reviewed by Coughlin and Eto suggest that the distribution of these events may be better approximated using a power law.[101] If confirmed, it means that current methods, which assume a Gaussian approximation, have underestimated the likelihood and magnitude of extreme events. From the standpoint of understanding the interaction between primary and secondary frequency control reserves, this is an area that requires further research. Reliability assessments are for the most part guided by the need to study and then prepare for rare and unexpected severe events which present the greatest risks to system reliability. Current methods, which assume a Gaussian approximation, therefore, will understate the likelihood of these events. Therefore, until the historic record can support more definitive assessments, the modeling assumptions made and their implications for extreme events should be made more explicit when conducting reliability studies.

## 6.3 The Interactions Between Primary and Secondary Frequency Control Reserves Cannot be Studied Using Current Dynamic Simulation Tools

In Section 5, we used commercially available dynamic simulation tools to study the adequacy and deliverability of primary frequency control actions to arrest rapidly declining frequency following the sudden loss of a large amount of generation. These tools are well suited for this type of analysis because they focus on millisecond-by-millisecond simulation of the interactions among the automatic controls of hundreds (and even thousands) of generators and loads within an interconnection over very short periods of time. As discussed in Section 5, these tools have been developed and refined by industry for more than 40 years, specifically to conduct studies of these very rapid interactions. The role of these tools in studying and setting reliability based limits for transmission system operations is well established.

The computational requirements of today's tools limit their practical application to simulations covering no more than about 20 to 40 seconds. This length of time is adequate for determining

[101] A power law, like a Gaussian, represents a specific mathematical relationship between two quantities. When the number or frequency of an object or event varies as a power of some attribute of that object (e.g., its size), the number or frequency is said to follow a power law. For instance, the number of cities having a certain population size is found to vary as a power of the size of the population, and hence follows a power law. See http://en.wikipedia.org/wiki/Power_law.

whether frequency decline can be arrested by the actions of primary frequency control and at what frequency the system will settle. This length of time is, however, too short to encompass the interactions between secondary and primary frequency control reserves. Indeed, the actions of secondary frequency control reserves to restore frequency to schedule following the actions of primary frequency control to arrest and stabilize frequency following the loss of generation, which can take 15 minutes to complete, are very rarely studied.

New study tools are needed that differ from the present generation of dynamic simulation tools in two basic ways. First, the study orientation needs to expand beyond simulation of the power system immediately following a loss-of-generation event, to also include simulation of the power system during periods of so-called normal operations when the interactions between primary and secondary frequency control reserves will affect whether primary frequency control reserves remain adequate (prior to a loss-of-generation event). Second, to study these interactions, we must consider much longer simulation periods. The type of operating scenario that should be studied is, for example, the evolution of an extreme wind ramping event over the period of, say, a half-hour or an hour and its effects on secondary frequency control reserves, and, if depleted, reserves for primary frequency control. The frequency response metrics developed in Section 2, especially the primary frequency response metric, can be used to measure the requirements for and assess the performance of primary frequency control reserves, as discussed in Section 3.4.4.

The length of time involved in these operating scenarios also points to a more basic and inescapable limitation that no simulation tool, alone, is capable of addressing: our inability to precisely simulate human judgment. We discuss this issue in the next subsection.

### 6.4 Managing the Interactions Between Primary and Secondary Frequency Control Reserves Involves Operator Judgments

The dynamic simulation tools in use by industry today were developed to study phenomena that occur too fast for human intervention to affect while they are in progress. Loss-of-generation events are, by definition, unplanned and sudden. The initial rate of frequency decline following the sudden loss of generation is determined solely by the amount of generation lost and the inertia of the power system at the time the generation is lost. The actions of primary frequency control to arrest and stabilize frequency are automatic. Dynamic simulation tools help us understand whether primary frequency control reserves are adequate to arrest the decline and prevent under-frequency load shedding.

In contrast, interactions between reserves of primary and secondary frequency control evolve over much longer time scales. In the example of an extreme wind ramping event, this may involve operating periods of a half-hour or more. Over these time scales, the decisions made by operators, prior to and during such an event, to redispatch on-line generation, to start up off-line generation, and to deploy demand resources or energy storage devices are the critical factors that will determine the adequacy of both primary and secondary frequency control reserves.

We cannot simulate these decisions with the same precision that is possible when we simulate the operation of automatic controls. The operating decisions of greatest interest must and will always be made on the basis of imperfect information (for example, an always imprecise forecast of when an extended wind ramp will begin, how long it will last, and how much wind generation will be affected). These decisions inescapably rely on judgments made by human operators. It is misleading to suggest that the standards for precision for simulation of automatic controls should be applied or even considered for simulation of decisions made by operators.

The central role of operator judgment must direct the requirements for future simulation tools to assist in operating power systems with increased variable renewable generation. Existing dynamic simulation tools will continue to have a role in studying the actions of automatic controls that must be planned in advance. However, new simulation tools are now required that focus on: the MW-per-minute ramping rate capabilities of generation equipment and demand response; uncertainty in forecasted rates of change of net system loads; and the implications of start up and dispatch decisions on the available head room, response rates, and deliverability of reserves that have been set aside to provide primary and secondary frequency control.

The role of these new tools should shift from a traditional one of providing support for off-line planning studies to one of providing on-line support for operations. Use of these tools for operator training simulations, for example, would be an important way for operators to gain the experience they will need to inform the judgments they will have to make based on what will always be imperfect information regarding the operating conditions they are expected to manage.

A critical complement to these tools is improved on-line monitoring of the availability and capabilities of the resources that are being counted on to provide primary and secondary frequency control actions. Combined with improved short-term forecasting tools, real-time visibility of the current capabilities of the resources in the on-line fleet will be an essential input to start-up and redispatch of generation and demand resources to ensure that reserves are adequate at all times. Here again, the primary frequency response metric developed in Section 2 can be used to articulate the minimum requirements for adequate primary frequency control and then to express the capabilities of available on line resources for direct comparison to these requirements.

## 6.5 Summary

Variable renewable generation will affect the interaction between primary and secondary frequency control reserves. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserves than has been the case in the past because we believe this is likely to emerge as the most significant frequency-response-based impact of variable renewable generation on reliability. This interaction has not been fully examined in prior studies of the secondary frequency control requirements associated with managing power systems with increased variable renewable generation, in part, because the focus of these studies has been on estimating overall increases in requirements for regulation and load-following on a year-round or average expected basis. As a result, the aspects of these requirements most important for ensuring adequate frequency response – namely, the potential for depletion of secondary frequency control reserves to then deplete primary frequency control reserves – during extreme (not only average or routine) circumstances has not been a focus of these studies.

Recent studies have made great strides in assessing the increased requirements for secondary frequency control reserves (i.e., increased requirements for regulation and load following). This report has not sought to improve upon these estimates although it has pointed to areas where greater clarity in future presentations of results will aid in assessing the impacts on reliability. This study has shown, however, that we cannot conduct definitive studies following the traditional approach embodied in today's dynamic simulation tools.

Deterministic studies will never replicate the inescapable role that operator discretion can, should, and, we expect, will always play in proactively deploying secondary frequency control reserves in the face of new and less familiar operating conditions involving extreme wind ramping events. Consequently, the focus should expand to include development of tools that can rapidly assess a wide range of "what if" operating scenarios and operator training using these tools, as well as to improving short-term forecasting, and providing better real-time information on the current capabilities of the resources available to provide primary and secondary frequency control. The frequency response metrics developed in Section 2 should be used to help guide these activities.

## 7. Further Work and Studies are Required to Address the Reliability Impacts Associated With the Integration of Variable Renewable Generation and Other Generation Resource Development

This section presents recommendations for further work and studies that are required now so that appropriate operating procedures can be put in place in the near future to ensure reliability as variable renewable generation increases and as other changes to the generation mix are considered. It is imperative that we pursue these activities pro-actively to achieve the twin goals of electricity reliability and increased resource diversity and security.

***Efforts should be accelerated now to better understand interconnection- and balancing authority-specific requirements for frequency control, especially in the Eastern Interconnection, considering among other things the frequency response metrics validated in this study***

It is widely acknowledged that the industry, especially in the Eastern Interconnection, is currently grappling with the implications of the declining quality of frequency control within the interconnection (NERC 2009d, NERC 2010a, NERC 2010b). Progress in improving our understanding of and addressing the root causes of declines in frequency response is important for protecting reliability both today and in the future as the nation's mix of generation sources changes. The potential impacts of variable renewable generation on interconnection frequency discussed in this study reinforce the need to address these issues proactively while levels of variable renewable generation are still modest. We recommend an acceleration of efforts to determine the root causes of the declining quality of frequency control, assess the risks posed for reliability, and take all actions necessary to ensure adequate frequency control is available in real time operation to ensure reliability. Improved data collection and ongoing monitoring of trends, in addition to empirically verified, calibrated system models for dynamic simulation studies, should be essential elements of these activities.

As discussed in Martinez (2010), the data available and thus the methods for calculating the actual frequency response of an interconnection, while fundamentally sound, continue to improve. The improvements stem, in part, from reliance on advanced monitoring technologies to record frequency events with greater granularity and precision. Ongoing, technically sound, and consistent measurements of frequency response using advanced monitoring technologies, coupled with standardized metrics based on, among other things, frequency nadir, are important improvements for monitoring these trends.

Empirically verified, calibrated dynamic system planning models are required to assess the significance of the root causes of the declining trend in interconnection frequency response, as well as the efficacy of options available to address these causes. Systematic procedures to improve the calibration of these models based on data recorded from actual events should be implemented on a routine basis.[102] It is our expectation that model calibration will require extensive field measurements and testing to verify and improve, where needed, the actual

[102] Following the 1996 west coast blackouts, the WECC was able to use information provided by research-grade versions of these technologies to assess why their dynamic simulation tools had not been able to predict the events experienced that summer.

performance characteristics of governors and plant secondary controls, as well as the impacts of the changing composition of customers' load on load damping.

NERC has several initiatives under way both to improve understanding of and address the declining quality of frequency control of the interconnections.[103] In view of the importance of implementing appropriate and timely actions to address this trend, especially considering state renewable generation mandates and goals, additional resources should be deployed to augment current efforts.

***Interconnections must schedule adequate primary and secondary frequency control reserves to both manage variations in net system load caused by increased levels of wind generation and withstand the sudden loss of generation, which can occur at any time.***

Our analytical and simulation studies have highlighted the essential roles that primary and secondary frequency control reserves play in ensuring reliability, especially the rapid and sustained provision of power from primary frequency control reserves immediately following the sudden loss of generation. Our simulations indicate that frequency control will be adequate in the Western and Texas interconnections for the generation and transmission infrastructure that system operators are expecting to be in place in 2012. Moreover, with planning and operating procedures that ensure adequate reserves for primary and secondary frequency control as well as targeted additional transmission, our simulations suggest that increased levels of variable renewable generation can be integrated reliably. Therefore, interconnections must schedule, commit, and maintain adequate primary and secondary frequency control reserves during normal operation in order to assure reliable operations after credible contingencies and to restore reserves after such contingencies.

Our dynamic simulation studies are examples of how dispatch of operating reserves following common procedures can lead to different amounts of primary frequency control reserves and thus different frequency response outcomes after the sudden loss of generation. Our review of the recent frequency performance of the interconnections finds that there are now predictable times during the day and within the hour when frequency excursions are consistently larger than at other times, suggesting that secondary and more importantly primary frequency control reserves have been drawn down. This may indicate that adequate primary and secondary frequency control reserves are not available at all times.

An interconnection must ensure that adequate primary frequency control reserves are in place and deliverable during normal operation and quickly restored after a contingency (FERC 2010b, NERC 2010a). It is important that these requirements take account of the interaction of primary and secondary frequency control when there is an unexpected loss of generation or rapid changes in net system load. That is, adequate secondary frequency control reserves are an important condition for ensuring adequate primary frequency control reserves.

[103] See, for example, NERC Frequency Response Initiative; NERC Frequency Response Standards Drafting Team http://www.nerc.com/filez/standards/Frequency_Response.html; NERC Reliability-based Control Project http://www.nerc.com/filez/standards/Reliability-Based_Control_Project_2007-18.html ; and NERC Transmission Issues Subcommittee, Model Validation Task Force http://www.nerc.com/docs/pc/mvtf/MVTF_Scope_12-9-09_PC_App.pdf.

Changes in operating procedures should be evaluated by system operators and planners through careful study using the improved tools and information discussed in the preceding recommendation. These operating procedures should consider the events that an interconnection must be capable of managing such as sudden loss of generation, variable energy generation and market operations. Such procedures should maintain adequate frequency control reserves without having to rely on under-frequency load shedding, which should only be utilized as a safety net (NERC 2003). Ultimately, the specific procedures could be expressed as measurable obligations for each balancing authority or each type of generation. Balancing authorities or reliability coordinators, in turn, could be responsible for confirming the capability and availability of the resources providing each form of frequency control.

***The frequency control capabilities of the interconnections should be expanded by increasing capabilities available within the current generation fleet and by pursuing new opportunities offered by wind generation, demand response, and energy storage.***

The economic dispatch of variable renewable generation may displace generation that otherwise would have provided primary and secondary frequency control reserves. Conventional generation is currently the principal source of reserves for primary and secondary frequency control. This study has identified displacement of these sources as a potential reliability impact of increased variable renewable generation. However, there are many currently under-utilized and potential future sources of primary and secondary frequency control available in addition to the conventional generation fleet that might be displaced. Tapping these sources will facilitate reliable integration of increased amounts of variable renewable generation. These sources include:

1. Expanded use of the existing fleet of generation (improved generator governor performance, increased operating flexibility of baseload units, faster start-up of units, etc.);
2. Expanded use of demand response that is technically capable of providing frequency control (potentially including smart grid applications), starting with broader industry appreciation of the role of demand response in augmenting primary and secondary frequency control reserves;
3. Expanded use of frequency control capabilities that could be provided by variable renewable generation technologies (primary frequency control, etc.); and
4. Expanded use of advanced technologies, such as energy storage and electric vehicles.

We recommend accelerated efforts, including, for newer, less familiar sources, research, development, and especially demonstration, to increase the supply of reserves that can provide primary and secondary frequency control. This includes all necessary reinforcements and additions to the transmission system to ensure deliverability. It may also require examination of current market incentives and compensation to provide primary and secondary frequency control reserves. The frequency response metrics developed in this study can be used to guide the development of these sources in contributing to the adequacy of frequency response.

There are currently significant under-utilized sources of conventional frequency control within the interconnections. Review of the system models provided by each of interconnections and discussion with industry experts confirms that many conventional generating units do not provide primary frequency control, for example, because they are run at full output leaving limited head room available for governors to access. Extensive enhancements to the models used in the WECC have focused on representing how plant secondary controls can sometimes override and withdraw primary frequency control provided by governors. Increasing the available supply of primary frequency control from plants that already are capable of providing this form of frequency control could likely take place relatively quickly because the assets are already in place. In addition, our interviews with operators revealed that they expect new market products for quick-start resources will unlock and provide them with expanded maneuvering capability. [104]

In addition, there are many new, as yet untapped, sources of frequency control available from demand response, variable renewable generators, and other advanced technologies. ERCOT's LaaR program, discussed in Section 5, is a tangible example of the important role that demand response can play in providing primary frequency control. State and federal regulators should continue their efforts to address challenges to the use of demand response in the U.S. electricity markets (FERC 2010a, FERC 2008, and FERC 2007).

Expanded frequency control capabilities are also being developed for variable renewable generation itself. Interviews with operators indicate that they are now routinely including curtailment and ramp rate provisions into the contracts they sign with variable renewable generators in an effort to reduce the need for additional frequency control capabilities. As noted earlier, wind turbine manufacturers are developing ways for their products to provide a form of inertia and primary frequency control. Opportunities for variable generation resources to provide primary frequency control should be explored.

Finally, there are several promising research and development demonstrations of energy storage technologies providing frequency control services (e.g., regulation). More time will be required to fully develop all of these sources, particularly those that are not yet commercially proven. However, there may be significant opportunities that exist and they should be pursued immediately. Efforts to expand the supply of primary and secondary frequency control reserves through advanced technologies should be accelerated.

***Comprehensive planning and enhanced operating procedures, including training, operating tools, and monitoring systems, should be developed that explicitly consider interactions between primary and secondary frequency control reserves, and address the new source of variability that is introduced by wind generation.***

Increased variable renewable generation presents substantial new schedule, commitment, and dispatch challenges for power system operators. Although operators have extensive experience anticipating and managing regular diurnal ramping requirements to meet system load from conventional generation resources, integrating variable renewable generation will at times require much greater commitment and dispatch flexibility or fleet maneuverability than has

[104] Any analysis of expanded use of existing resources must include consideration of fuel supply impacts. See, for example, Interstate Natural Gas Association of America (2009).

previously been required. The characteristics of what is required and how it should be deployed may differ significantly and are currently less predictable than the requirements for managing familiar daily load ramps. Yet, as this study has demonstrated, it is essential that this maneuverability be provided in ways that safeguard reliability by ensuring the adequacy of primary and secondary frequency control reserves during operations.[105] We recommend aggressive development and adoption of comprehensive planning and enhanced operating procedures, including training and specific operating tools. These tools should anticipate minimum requirements for primary and secondary frequency control reserves, explicitly consider the interactions between these two types of reserves, and continuously monitor their adequacy during operations. Continued collection and analysis of variable renewable generation data is essential for anticipating and preparing for all operating conditions.

The planning procedures must study the requirements for primary and secondary frequency control, and consider the interactions between these two forms of frequency control given expected increases in the variability of net system load and the unexpectedness of sudden loss of conventional generation. The procedures must determine an optimal mix of on-line versus off-line secondary frequency control resources, giving consideration to the level of uncertainty in variable renewable generation forecasts. Further, conventional unit scheduling, commitment and dispatch will need to take into account primary and secondary frequency control capabilities in addition to traditional economic and security considerations.

Enhanced operating procedures are needed that address the new and sometimes unpredictable, sometimes very rapid, and sometimes very extended ramping requirements that will be faced by operators managing power systems with significant penetrations of variable renewable generation. The procedures must provide unambiguous guidance regarding the actions operators must take to acquire and dispatch resources in order to manage frequency effectively as information becomes available (and evolves) on the likelihood, magnitude, and duration of these new types of ramping events. And because extreme ramping events, by definition, will not be regular occurrences, operator training will be essential for developing the knowledge and skills required to implement the procedures seamlessly when the need arises. Efforts by system operators to begin developing these procedures and training resources should begin immediately to develop familiarity with needed changes.

Present operating procedures and training are based on decades of data which has provided information necessary to calculate probability distributions of events that can be expected to occur during operations. There is not a similar amount of data from variable renewable generation. Hence, ongoing and expanded wind (and solar) data collection and analysis will be essential for characterizing and preparing for the extreme events that present the greatest operating challenges. To prepare for these events, operating procedures and training should be accompanied by the development and adoption of new tools and monitoring capabilities to improve anticipation of and preparation for unusual operating conditions. Efforts are already under way to improve short-term forecasting accuracy, especially the timing and magnitude of variable renewable generation ramping events; these efforts should be encouraged. Still, it must be recognized that our experiences with wind variability are in their infancy.

[105] Conventional unit scheduling, commitment and dispatch will need to take into account primary and secondary frequency control capabilities in addition to the traditional economic and security constraints.

Knowing what is coming should be complemented by improved situational awareness of the available capabilities of the resources that will be or are being relied on to provide primary and secondary frequency control actions. This includes on-line assessment to determine the levels required, monitoring of the resources providing each form of control, including the remaining head room available from each resource, and location with respect to transmission limits that might constrain deliverability of the frequency control actions that these resources might provide. Improving situational awareness may require new equipment as well as information that is not currently available to operators. Thus, new tools, data collection, and analysis procedures will also be required.

***Requirements for adequate frequency control should be evaluated in assessments of the operating requirements of the U.S. electric power system when considering new potential sources of generation and the retirement of existing generation***.

This study has examined a case study of the frequency-response impacts of increased variable renewable generation on the reliability of each of the three U.S. interconnections. In examining the many ways increased variable renewable generation might affect the frequency behavior of a power system following the sudden loss of generation, the study has demonstrated the importance of frequency-response-based metrics for assessing the adequacy of primary and secondary frequency control reserves. Frequency control is affected not only by the characteristics of variable renewable generators, it also depends on the characteristics of the remainder of the power system, which includes other forms of renewable generation, conventional generation, the transmission system, and the customer loads served. Thus, our study has been guided by the recognition that adequate frequency control is a fundamental requirement for reliable operation of any power system. Going forward, new technologies, economic considerations, and public policies will continue to alter the future composition of our power system (including the addition of other forms of variable renewable generation, changes in nuclear generation, retirements of generators, and changes in the electrical characteristics of customer loads, among other factors). We recommend, therefore, that reliability studies of frequency control using metrics developed here be conducted routinely on an interconnection wide basis as important and ongoing inputs to the deliberations that will guide future developments and decisions. We further recommend that these studies guide the development of the systems and procedures needed to manage these changes to the power system.

It is important that future studies extend the findings of the present study by using, among other tools, dynamic simulations, to explore or clarify the aspects of their scopes that are relevant to frequency response. For example, studies that focus on estimating future requirements for secondary frequency control (i.e., regulation and load following), should provide greater detail on the expected performance of these forms of frequency control, the implications of this performance for primary frequency control reserves, and the assumptions and uncertainties inherent in the forecasted variability of renewable generation, particularly for the times when load and variable resources are ramping in opposite directions.

In addition, we suggest that studies of the future U.S. electric power system also address topics such as the impact of generation retirements and new nuclear generation on interconnection frequency response. For example, many of the generators slated for retirement are also relied upon for frequency control. In addition, today's nuclear generation fleet currently provides no frequency control although this may not be true of future nuclear generators. In both examples, the questions to be addressed are: 1) What are the future requirements for frequency control and 2) What resources can/should be relied to provide frequency control?

As identified in prior sections, the metrics developed in this study will provide guidance as to the ability of any future mix of generation and load facilities to provide adequate primary frequency control in order to protect the reliability of the system. The metrics can be used to determine the future requirements for frequency control and to manage the reliable integration of future resources.

**A Call to Action**

The physical limits to the reliable integration of variable renewable generation are already well understood to be the transmission infrastructure required to deliver this generation to load. This study has focused on the important requirements related to interconnection frequency response that must also be addressed to ensure reliable operation.

This study has confirmed the validity of using frequency response as predictive metrics to assess the reliable operation of interconnected systems that are managing major changes in generation resources, particularly such as the integration of variable renewable generation. The concept will work however, with other changes in generation mix, and changes to existing resources such as plant retirements. Although transmission operators have conducted a number of studies to address many of the operating issues related to the integration of variable renewable generation, these studies have not focused on primary frequency control or on the interaction between reserves for primary and secondary frequency control. At the same time, there is a separate growing industry concern regarding the declining quality of frequency control. As the amount of variable renewable generation grows and other changes are made to the generation resource mix, it is essential to understand and address the root causes of this trend and take actions to ensure that adequate frequency control reserves are scheduled by balancing authorities.

Ultimately, the technical and institutional issues that must be addressed in integrating variable renewable generation and other types of generation depend on the unique features of and resources available within each interconnection, the ability to predict the operation of these generation resources, and the availability of new sources of frequency control such as demand response and energy storage. Therefore, careful study, planning, and deliberate actions will be required by each interconnection to ensure the continued reliability of the U.S. electric power system.

## Glossary of Terms

Area Control Error (ACE)*: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Automatic Generation Control (AGC)*: Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Balancing Authority (BA)*: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

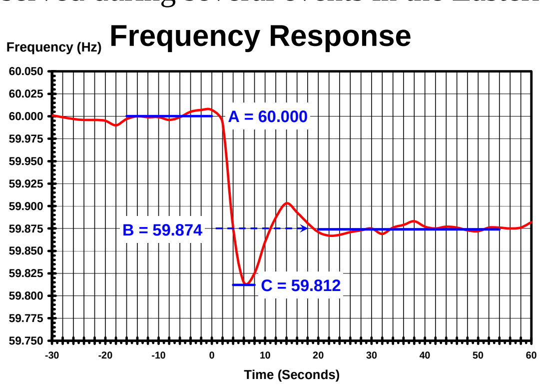
Contingency reserve*: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Demand*: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

Frequency [i]: The rate at which a repeating waveform repeats itself. Frequency is measured in cycles per second or in hertz (Hz). The symbol is "F".

Frequency deviation*: A change in Interconnection frequency.

Frequency nadir +: Refers to the initial frequency at which the increase in generation due to governor response and load response equals the initial sudden loss of generation (dP). This is otherwise known as Point C as identified by the NERC Resource Subcommittee in the following example illustration. It is noted that the frequency nadir or Point C may not necessarily be the lowest frequency experienced after the sudden loss of generation as observed during several events in the Eastern Interconnection.




Frequency response*: (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Frequency-responsive demand response +: Agreed to load shedding by end use customers that complements governor response. This load is typically triggered by relays that are activated at higher frequencies than Under Frequency Load Shedding.

Governor response+: The autonomous and automatic net change in synchronized generator output to oppose frequency changes that is available to the power system within a few seconds

Head room+: The difference between the current operating point of a generator and its maximum operating capability.

Inertia[i]: The property of an object that resists changes to the motion of an object. For example, the inertia of a rotating object resists changes to the object's speed of rotation. The inertia of a rotating object is a function of its mass, diameter, and speed of rotation.

Inertial response+: The energy that is injected into or withdrawn from the rotating generators and motors when frequency is changing (accelerating or decelerating) due to changes in energy stored in the connected rotating machines. It is measured in MW * Seconds. The amount of energy transferred is dependent on the total mass, diameter, and delta in speed of the masses that are part of or directly connected to a generator or motor. It includes rotors, turbines and other masses that are directly connected to the shaft of the generator or motor. The magnitude of inertial response determines the rate of frequency change between the initial frequency and the nadir and is determined by the percentage of generation lost, the effects of load damping (D) and normalized system inertia (H) according to dP/ (D+2H).

Interruptible Load*: Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load damping[¥]: The changes in power absorption of the connected frequency-sensitive portion of demand to oppose a frequency deviation.

Load following[i]: A pre-determined ramp of generation output intended to reduce the reliance on regulation to provide the difference between actual generation and forecasted demand.

Non-spinning reserve*: 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

Off-line reserve[§]: The off-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. (Non-spinning reserve is a part of off-line reserves.)

On-line reserve[§]: The on-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection.

Operating reserve*: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Other on-line reserves[§]: Generation resources and demand side managemnet that can be brought to bear outside the continuum of regulating or spinning reserve (i.e. on four hours' notice).

Other off-line reserves[§]: Generation resources that can be started and brought to bear at their defined output outside the continuum of non-spinning reserves for some defined time.

Plant secondary control[@]: Secondary control refers to controls effected through commands to a turbine controller issued by external entities. It is common for a modern power plant to have several distinct modes of secondary control implemented within the plant and, also, to be able to accept secondary control inputs from sources external to the plant. For the purpose of this report, plant secondary control refers to all forms of secondary control that are not based on system-wide frequency management objectives.

Primary frequency control[§]: The result of autonomous, automatic, and usually sustained net change in power output from generation and load that is synchronously connected to the power system to immediately oppose all frequency deviations. (Primary Control is more commonly known as Frequency Response. Frequency Response can be determined within the first few seconds following a disturbance .)

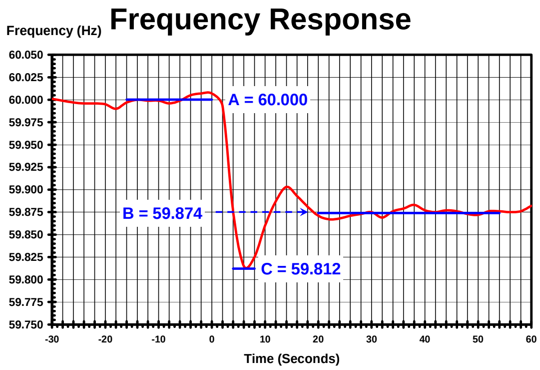
Regulation[¥]: The portion of operating reserves, above that needed to account for load forecasting error, equipment forced and scheduled outages, and local area protection, that are needed to balance generation and demand at all times. Regulation can be accomplished by committing on-line generation or demand side resources whose output is raised or lowered (through the use of automatic generating control equipment and load following) as necessary to follow the moment-by-moment differences between net generation and net demand.

Regulating reserve*: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Secondary frequency control+: The result of pre-arranged or centrally dispatched generation or DSM resources on a balancing authority basis to balance generation and load by accounting for net interchange and frequency bias. (Secondary Control is a balancing service deployed in the "minutes" time frame and accomplished using the Balancing Authority's control computer, load following, and the manual actions taken by the dispatcher to provide additional adjustments. Secondary Control includes the minute-to-minute balance throughout the day and is used to restore frequency to normal following a disturbance and is provided by both Spinning and Non-Spinning Reserves) §

Settling frequency[¥, #]: Refers to the third key event during a disturbance when the frequency stabilizes following a frequency excursion.[106] The NERC Resource Subcommittee refers to this term as Point B in the above example illustration. Point B represents the interconnected system frequency at the point after the frequency stabilizes due to governor action but before the contingent balancing authority takes corrective AGC action.

[106] The time after the initiating event will vary between interconnections and will depend upon when the frequency actually stabilizes.




Spinning reserve*: Unloaded generation that is synchronized and ready to serve additional demand.

Tertiary frequency control§: Encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and Reserve restoration following a disturbance is a common type of Tertiary Control.

Under-frequency load sheddingⁱ: A safety net designed to operate in order to preserve the generation in a portion of a region that has experienced major generation loss by shedding non-interruptible or firm load. The conditions assume that the region is not interconnected with the rest of the interconnection and that the generation will not trip by limiting the magnitude and time of off nominal frequency associated with the event. It is not intended to operate under even extreme design conditions.

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