Attachment 3

KEMA Report

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Governor

RESEARCH EVALUATION OF WIND GENERATION, SOLAR GENERATION, AND STORAGE IMPACT ON THE CALIFORNIA GRID

PIER FINAL PROJECT REPORT

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

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- Transportation

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Abstract

This report analyzes the effect of increasing renewable energy generation on California's electricity system and assesses and quantifies the system's ability to keep generation and energy consumption (load) in balance under different renewable generation scenarios. In particular, researchers assessed four key elements necessary for integrating large amounts of renewable generation on California's power system. Researchers concluded that accommodating 33 percent renewables generation by 2020 will require major alterations to system operations. They also noted that California may need between 3,000 to 5,000 or more megawatts (MW) of conventional (fossil-fuel-powered or hydroelectric) generation to meet load and planning reserve margin requirements.

The study examines the relative benefit of deploying electricity storage versus utilizing conventional generation to regulate and balance load requirements. To reach storage's full potential, researchers developed new control schemes to take advantage of higher response speeds of fast storage, examined storage performance requirements, and noted maximum useful amounts to meet both regulation and balancing requirements. Researchers also noted the effectiveness of storage technologies, in comparison to conventional generation, to meet energy systems' need to accommodate large output changes of energy resources in a relatively short period.

The report provides policy and research options to ensure optimum use of electricity storage with the associated increase in renewable generation connected to the system.

Keywords: Renewable energy, solar, wind, energy storage, integration, AGC, ACE, ancillary services, frequency regulation, balancing, ramping, RPS, grid, independent system operator

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Executive Summary

Introduction

The integration of renewable energy resources into the electricity grid has been intensively studied for its effects on energy costs, energy markets, and grid stability. These studies all conclude that the variability and high-ramping characteristics of renewable generation create operational issues. However, there have been few efforts to precisely quantify these effects with a highly dynamic model that simulates system performance on a time scale of one second or less, compared to a one-hour basis that is typical in production cost simulations. This study constitutes such an effort.

Project Purpose

This research identifies key issues and assesses the effects of high renewable penetrations on intra-hour system operations of the California Independent System Operator (California ISO) control area. It also looks at how grid-connected electricity storage might be used to accommodate the effects of renewables on the system. To do this, researchers used high-fidelity modeling to analyze the effects of planned additions of renewable generation on electric system performance. The research focuses on required changes to current systems to balance generation and load second-by-second and minute-by-minute, and to do so in the most cost-effective manner.[1] The study also assessed potential benefits of deploying grid-connected electricity storage to provide some of the required components—including regulation, spinning reserves,[2] automatic governor control response[3], and balancing energy—necessary for integrating large amounts renewable generation.

Project Objectives

The objective was to measure the effects of the variability associated with large amounts of renewable resources (20 percent and 33 percent renewable energy) on system operation and to ascertain how energy storage and changes in energy dispatch strategies could accommodate those effects and improve grid performance. This project used a new modeling tool—KEMA's proprietary KERMIT model, which employs a dynamic model of the power system and

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[1] Automatic generation control operates the generators that supply regulation services (up and down) every 4 seconds to keep system frequency and net interchange error as scheduled. The *real-time dispatch* buys and sells energy from generators participating in the real-time or balancing market every five minutes to adjust generator schedules to track a system's load changes.

[2] Regulation in MW is the amount of second-by-second *bandwidth* or controllability used in balancing generation and load. Spinning reserve is the excess amount of on-line generation capacity over the amount required to supply load and available to respond to sudden load changes or loss of a generator.

[3] Governor response is the near-instantaneous adjustment of each generator's output in response to system frequency changes, caused by the generator speed-governing device.

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generators—to assess the electricity system's performance in one-second to one-day time frames using techniques that captured the full range of system dynamic effects.

Specific objectives of the research were as follows:

1. Calibrate the dynamic model—using existing electricity-generation-fleet capacities, actual daily schedules, loads, interchange, area control error,[4] and frequency data provided by the California ISO on four-second and one-minute bases as described below—and extend that model to 2012 and 2020 time frames with 20 percent and 33 percent renewables portfolio standard levels. Assume planned changes to the generation fleet (retirements, upgrades) and renewable capacities per current California Public Utilities Commission-developed forecasted portfolios and state forecasts for load growth.
2. Assess droop, ancillary services, and balancing needs[5] with current system controls.
3. Assess the effect of increased storage and regulation and balancing on system performance.
4. Examine automatic generation control[6] algorithms for storage.
5. Determine the relative benefits of different amounts of storage.
6. Determine storage characteristic requirements.
7. Determine the storage-equivalent of a 100-megawatt (MW) gas turbine.
8. Identify issues with incorporating large-scale storage in California.

Outcomes

Project outcomes, in the order of project objectives, are as follows:

1. The model was successfully calibrated to match historical data.
2. System performance degraded, in terms of maximum area control error excursions and North American Electric Reliability Corporation control performance standards, significantly for 20 percent renewables penetration and became extreme at 33 percent

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[4] Area control error is the deviation from scheduled interchange power flows (in MW) plus the system bias (a constant) times the deviation in system frequency, as defined by the North American Electric Reliability Coordinator.

[5] Droop is the gain on the generator's local speed-governing device, that is, how sensitive the generator's output is to changes in system frequency. Ancillary services are those services that generators *sell* to the California ISO to enable system reliability and to follow load. Balancing energy is the energy the California ISO buys and sells every five minutes via real-time dispatch to follow load.

[6] Automatic generation control is the computer system at the California ISO that controls the generators in real time to balance load and generation second-by-second

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renewables penetration, using the same automatic generation control strategies and amounts of regulation services as today. Without adjustment to the automatic generation control and the amount of regulation procured maximum area control error excursions went from a typical band today of the order of ±100 MW to several times that in the 20 percent renewables scenario and to as much as 3,000 MW of error in the 33 percent scenarios. Such an excursion is not tolerable and would possibly cause other system protective devices to operate such as interrupting transmission flows to adjacent power systems.

3. The amount of regulation, without storage and using existing control algorithms, required to maintain system performance within acceptable limits for a 20 percent renewable case in 2012 was ±800 MW in the up and down direction, roughly double today's amount.[7]
4. The amount of regulation and imbalance energy dispatched in real time, without storage and using existing control systems to maintain system performance, within acceptable limits during morning and evening ramp hours for 33 percent renewable cases in 2020 was 4,800 MW. The amount of regulation and imbalance energy dispatched in real time, without storage and using existing control algorithms, to maintain system performance within acceptable limits during non-ramp hours to address system volatility for the 33 percent renewable cases in 2020 was approximately an additional 600 MW. By comparison, 1,200 MW of storage added to the baseline 400 MW of regulation provided superior results by comparison. (See Table 1).
5. Generally, the largest deviations in system performance occurred twice per day, once during the morning and once during the evening, corresponding to the interaction of diurnal production of wind and solar resources and fluctuation of demand. Accordingly, degradation of system performance appears to be predominantly caused by renewable ramping in the morning and evening along with traditional morning and evening load ramps.
6. Increasing regulation amounts, without the use of storage and improved control algorithms, can improve system performance. However, roughly 2-to-10 times the amount of today's regulation and balancing capacity would be required to maintain system performance absent other operating protocols, such as limiting ramp rates and new services that could be developed as alternatives to address renewable ramping as well as scheduling and forecasting errors.
7. Adjustments to the droop settings of generators from the current 5-10 percent had little effect on system performance.
8. Design changes to the automatic generation control mathematics and calculations allowed the automatic generation control to make better use of the higher response

[7] Regulation in MW is the amount of second-by-second *bandwidth* or controllability, California ISO-procured from participating generators, used in balancing generation and load.

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speed of the storage devices and resulted in better system performance with less overall regulation procured.

9. Large-scale storage can improve system performance by providing regulation and imbalance energy for ramping or load following capability. The 3,000 to 4,000 MW range of fast-acting storage with a two-hour duration achieved solid system performance across all renewable penetration scenarios examined. (The range 3,000-4,000 MW reflects the different days studied and the levels of incremental storage simulated, for example, 3,200 MW, 3,600 MW, and so on.)
10. Existing battery technologies appear to have the capabilities required to manage renewable integration, including two-hour durations and ramping capabilities of 10 MW/second or greater.
11. On an incremental basis, storage can be up to two to three times as effective as adding a combustion turbine to the system for regulation purposes. The relative effect of each depends on how much storage or regulation and balancing is already in the system. For example, when the system has sufficient resources for stabilizing system performance, the incremental benefit of either technology approaches zero. This is an incremental ratio of the effect a combustion turbine or a storage device each have on system performance, and not an indicator of how much total capacity of each technology may be needed to manage the large ramping phenomena.
12. Without the use of storage, ramping of combustion turbine generators and hydro-electric generation is likely to increase. This may likely have detrimental effects on equipment maintenance costs and life of the equipment, and greenhouse gas emissions because the resources will be asked to generate more often at less than optimal production ranges as well as to remain *committed*—that is, on-line—in anticipation of ramping needs.

Conclusions

Governors' executive order S-14-08 established a goal of 33 percent energy from renewable resources to serve California customer load by 2020. This will require significant increases in ancillary services (regulation) and real-time dispatch energy, with attendant changes in the day ahead schedules of generation production by hour to ensure that such services are available—that is, that enough generators will be on-line with excess capacity available during each hour. Such a change in scheduling practice will incur additional economic costs in the production of power. The use of storage in conjunction with new control and generation ramping strategies offers innovative solutions that are consistent with the need to continue to comply with current North American Electric Reliability Corporation system performance standards. Electricity storage promises to be a useful tool to provide environmentally benign additional ancillary service and ramping capability to make renewable integration easier. However, while this report concludes that the system flexibility provided by storage is more efficient than equivalent conventional generation capacity, it has not performed a comparative cost-benefit analysis either in terms of fixed capital or variable costs.

Based on the outcomes observed, researchers made the following conclusions:

1. The California ISO control area as simulated would require between 3,000 and 5,000 MW of regulation and energy for balancing and ramping services from *fast* resources (hydroelectric generators and combustion turbines) for the scenario of 33 percent renewable penetration scenario in 2020, absent other measures to address renewable ramping characteristics (See Table 1). The range reflects the different seasonal patterns in the days studied, as well as the mix of fast storage (capable of 10 MW/second ramping) versus fast new and upgraded conventional units (combustion turbine and hydro expected as of 2020). The large ramping requirement is driven by the combination of solar generation and wind generation variability that is forecasted for the 33 percent scenario. Included within this variability is the steep, yet highly predictable, production curve associated with solar resources as the sun comes up in the morning and sets in the evening. Some of this ramping requirement can be satisfied by altering the likely system commitment for conventional generation to maintain a large amount of gas-fired combustion turbines on-line for ramping. It also may be possible to alter the scheduling of hydroelectric facilities and pump-storage facilities so as to assure adequate ramping potential at critical periods, although there are environmental and operational difficulties associated with this potential solution. Finally, altering or controlling the ramp rate of wind and solar resources for known ramping events such as sunrise and sunset can reduce regulation, balancing, and ramping requirements, but at the cost of *curtailing* renewable output. Because the study simulated only four days (to represent the seasonality) and did not focus on scheduling protocols, these results with respect to the ramping problem should be taken as indicative of the order of magnitude of the problem and not a quantitative basis for planning. As recommended below, additional study will be required to determine the amount of operational reserves required in 2020.

2. The moment-by-moment volatility of renewable resources may need up to twice the amount of automatic generation control or regulation compared to today's levels in the 20 percent scenario and somewhat more in the 33 percent. This is consistent with prior studies and manageable based on simulations using existing and anticipated sources of supply.

3. Generation ramping requirements to meet the morning load increase and the evening load decrease, as well as potentially other large changes in net load during the day, require large changes to generation dispatch in very short periods and may be the major operational challenge to ensuring reliability under a 33 percent renewable scenario. Under the 33 percent renewable scenario, these ramps will be difficult to manage in the current paradigm of regulation and balancing energy/real-time dispatch, where automatic generation control and real-time energy dispatch must be used to counteract large renewable ramping behavior and scheduling / forecast errors. There should be an investigation into new protocols for renewable ramping and provide incentives for incentivizing the needed flexibility to reduce its effects would appear to be in order. Also, as the study used an algorithm for real-time dispatch more reflective of the older

balancing energy system than the new MRTU algorithm[8], these figures should be taken as indicative rather than absolute as the extent to which MRTU will manage these effects was not investigated. However, errors in renewable forecasting and scheduling will still provide major challenges.

4. Fast storage (capable of at least 5 MW/second if not up to 10 MW/second in aggregate) is more effective than generally slower conventional generation in meeting the need for regulation and ramping capability and storage carries no additional emissions costs and limited cost penalties in terms of sub-optimal dispatch costs. The full benefit of fast storage for system ramping and regulation and balancing is achieved only via the use of automatic generation control algorithms developed specifically for the integration of storage resources. One such control algorithm was developed during the course of this study and is described in the report in detail.

5. Use of storage avoids greenhouse gas emissions increases associated with committing combustion turbines strictly for regulation, balancing, and ramping duty.

6. A 30-to-50 MW storage device is as effective or more effective as a 100 MW combustion turbine used for regulation purposes, given the use of the storage-specific control algorithms as mentioned in (4) above, the faster response of the storage as compared to a gas turbine, and the fact that a 50 MW storage device has an approximate – 50 to + 50 MW operating range that is equivalent to a zero to 100 MW range for a combustion turbine for regulation purposes.

Table 1 summarizes the quantitative benefits of using storage to address minute-to-minute volatility by noting its impact on system performance from 10 a.m. to 4 p.m. Major renewable resource and load ramping behavior occurs outside of this time frame and therefore does not include the periods that triggered the highest levels of balancing energy in real time. The table illustrates three metrics to gauge system performance—area control error, frequency deviation, control performance standard 1[9]—and notes relative amounts of regulation required to achieve similar performance between conventional resources and storage. Typical control performance standard 1 values are in the range of 180 to 190 percent, with an acceptable minimum of 100. Therefore, to avoid degradation of service reliability, that target system performance was similarly used in this study. Thus, larger figures of merit for control performance standard as

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[8] During 2004 – 2009 the California ISO replaced the original real-time dispatch software with a new version, called *MRTU*, which employed more sophisticated mathematics and modeling to better and more economically adjust generation every five minutes.

[9] Area control error and frequency deviation were defined above. Control performance standard is a calculation of the system performance in terms of maximum area control error which is specified by the National Electric Reliability Coordinator so as to guarantee that all the interconnected power systems balance their load and generation *well enough* to maintain system reliability.

well as frequency deviations reflect worse system performance. In general, Table 1 demonstrates that storage can achieve better performance in the system per MW installed than regulation from conventional generation. (In this table, as in many other tables and figures in the report, the text *regulation* is a proxy for the net amount capacity capable of fast ramping to follow system changes via regulation and balancing energy.) Today, the California ISO has separate *reg up* and *reg down* products[10] and is able to procure different amounts of each. This simulation assumed symmetric *reg up* and *reg down* allocations throughout so that potential incremental savings associated with reduced procurement in one direction are not captured.

Table 1. System performance with storage and increased regulation during non-ramping hours (10 AM to 4 PM) (data provided by the authors during the conduct of the project)

Scenario	Added Amount (MW)		Worst Maximum Area Control Error (MW)		Worst Frequency Deviation (Hz)		Worst Control Performance Standard 1 (percent)	
	Regulation	Storage	Regulation	Storage	Regulation	Storage	Regulation	Storage
2010 RPS*	400	200	477	311	0.0470	0.0438	184	195
2020 RPS* Low[11] Estimate	800	400	480	493	0.0610	0.0609	190	190
2020 RPS* High[11] Estimate	1,600	1,200	480	344	0.0610	0.0590	191	196

*RPS: Renewables Portfolio Standard

Overall, study conclusions on the regulation necessary to address the moment-to-moment variability appear to compare well to other similar studies, including a 2007 study by the California ISO entitled *Integration of Renewable Resources*. For example, this analysis recommends at least 400 MW or more additional regulation (but not balancing energy) for the 20 percent Renewables Portfolio Standard scenario while the California ISO report recommends 250 to 500 MW more depending on the season. The California ISO study did not focus on the 33 percent Renewables Portfolio Standard scenario.

Recommendations

The research study considers only a handful of days throughout the year. Additional research using a larger data sample is essential to better gauge the likelihood of impacts over a year and

[10] The California ISO procures regulation in an asymmetric fashion – it can procure the ability to move generators up at a different amount than it does down.

[11] See Table 3 on page 27 for High-Low Generation Capacity by Type. These are projections for the amount of renewable resources that will be online in 2020 to meet the RPS. A low estimate and a high estimate are detailed in Table 3.

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to ensure the full range of potential issues have been identified. In addition, the development of improved concentrated solar modeling would facilitate quantification of the effects of geographic and technological diversity and thereby help identify the extent to which ramping of this resource could be managed. That is, if the concentrated solar thermal plants are in different geographic locations they might ramp up and down during the day at different times, especially if cloud cover as opposed to sunrise/sunset is the driving factor. Different technological designs of the plants may lead to faster or slower ramping, and even to the ability to control ramping to some extent. Finally, better information about the extent to which out-of-state renewable imports will be shaped and firmed by balancing authorities will help to better gauge California ISO-specific needs.

Research Recommendations

- **Add additional days to the sample.** Obtain results that reflect a larger sample of days to understand the statistical behavior and extremes in renewable volatility and ramping.
- **Develop dynamic concentrated solar generation model.** Ramping was identified as a significant issue related to concentrated solar generation resources. Develop a model to more thoroughly understand concentrated solar generation, particularly with respect to developing a better understanding of the dynamic performance of such resources and how to manage ramping issues. Given that wide-scale solar technology is in its infancy and can be expected to develop rapidly, improving modeling capability will require collaboration with resource developers.
- **Examine geographic and temporal diversity of renewables.** Understand the statistical behavior and extremes in renewable resource volatility and ramping. That is, how variable are renewable resource's production during the day in response to weather conditions (wind speed, cloud cover, and so on).
- **Carefully investigate the interaction of renewable energy forecasting and scheduling with generation scheduling to understand the potential ramping requirements of conventional generation / electricity storage imposed especially by forecast errors.** The hourly scheduling protocol that establishes a fixed schedule for the entire hour a full hour prior to the operating hour seems to be a source of much of the ramping difficulty. Errors in the timing of forecasted renewable ramps of as little as 15 minutes can have large effects. Attacking this problem with large amounts of regulation and balancing or electricity storage may not be as productive as other alternatives including renewable resource ramp rate limitations [12], sub-hourly scheduling protocols [13], investments in

[12] Operational limits imposed by the California ISO on renewable resources that specify the maximum rate of change of their net production.

[13] Forecasting and scheduling renewable production on a 15- or 30-minute basis instead of hourly as is done today.

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short-term renewable production forecasting, or other changes in market service and interconnection protocols.

- **Validate ancillary service protocols for electricity storage.** Future research and development is needed on advanced control strategies linked to wind and solar power forecasting. This will affect the research, development, and engineering directions taken by the energy storage industry.

- **Conduct a cost analysis for solution alternatives.** This report looked at the technical potential of electricity storage only. Cost considerations will weigh into how to balance different options, including promoting incentives for existing conventional generation to provide added flexibility, the relative value of different flexible resources, and other ramp mitigation measures.

- **Examine the use of demand response as an additional ancillary service to facilitate renewable integration and potentially the use of electricity storage.** It is not yet apparent that demand response programs can meet all ISO requirements to provide the high-speed response required to manage renewable ramping. If it turns out that the benefits of rapidly responding demand response are feasible and consistent with system needs, that knowledge will be important in the design of smart grid capabilities for demand response and the associated protocols.
- **Continue development of automatic generation control algorithms for control of multiple electricity storage resources and conventional generation at high renewables levels.** Investigate the value of adding a 5-minute or 10-minute *look-ahead* feature in the automatic generation control algorithm that would predict the short-term changes in load and renewable generation resources.
- **The problems that may occur off-peak** due to wind volatility were implicitly covered in the study in that the selected days were studied for the full 24 hours. The results for intra-hour volatility and automatic generation control requirements are implicit in the results. However, the behavior of the system for major wind ramping phenomena off peak were not studied, and the days selected may not indicate the potential magnitude of the problem. Additional studies that look at the off peak hours in particular may be in order.

Policy Recommendations

There are two major policy options that should be considered a result of this study, and several secondary issues are raised.

First, the possible resolution of how to manage the operational challenges of renewables will have five elements that will need to be addressed:

- Use fast storage for regulation, balancing, and ramping either as a system resource to address aggregate system variability or as a resource used by renewable resource operators to address individual resource variability and ramping characteristics.

- Procurement of increased regulation, balancing, and reserves by the California ISO.
- Possible imposition of requirements on renewable resources to accommodate their effects on grid operation, such as ramp rate limits on renewable resources, more accurate short-term forecasting, sub-hourly scheduling, and other possibilities.
- Changes to the market system to encourage fast ramping by conventional generation resources.
- Use of demand response as a ramping/load following resource, not just a resource for hourly energy in the day-ahead market or for emergencies.

This study primarily investigated the first two items. Subsequent efforts are recommended to study the effectiveness of ramp limits on renewables and the effectiveness of demand response for load following. Introducing the need for these latter two elements will stimulate the market debate among parties affected. While the study does not offer research to specifically identify the value of limiting renewable resource ramps, this option may play a key role in ensuring the efficient application of capital investment for new flexible capacity in a manner consistent with reducing greenhouse gas emissions at a reasonable cost to consumers.

Second, the use of fast storage as a system resource for renewables management appears to require technical performance characteristics of the various types of electricity storage, in particular, minimum rate of change capabilities of charging/discharging power, such as minimal ramping capabilities. If these are to be imposed as requirements for a new regulation ancillary service then the electricity storage development community needs to be aware before large investments are made in technologies that are not capable of this performance.

Secondary policy issues that were identified include:

- Should electricity storage be directly linked to renewable installations or be procured by the California ISO as an ancillary service on behalf of the system as a whole? Whether renewable developers are required to provide or procure storage capabilities or the California ISO is required to procure it on behalf of the system as a whole will affect the state's generation resource planning. The location of the storage (at the renewable resource's location or elsewhere) will affect the planning of future power transmission lines as well. This question is linked to the question of whether to ramp limit renewables.
- As indicated by this study, procurement of very large amounts of regulation, balancing, and reserves from conventional units may cause market distortions. If so, new market and regulatory protocols may be required.
- What incentives at the federal or state level are indicated to support electricity storage resource development? How should these incentives be linked to policy measures designed to encourage renewable resources development such as tax incentives? Eligible electricity storage should meet the technical performance characteristics identified in this report as validated and amended by the California ISO to qualify. The state may

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wish to communicate this concept to the United States Congress, which is contemplating investment tax credits for storage.

- This study used existing California ISO system performance criteria as the benchmark and developed regulation and load following requirements on the assumption that any significant degradation of these is unacceptable. However, North American Electric Reliability Corporation and/or Western Electricity Coordinating Council may establish new performance criteria developed with high Renewables Portfolio Standard operations in mind; should that be the case, then the study would need to be reassessed in light of any new policies.

Benefits to California

The prospective benefits to California from the development of fast electricity storage resources for use in system regulation, balancing, and renewable ramping mitigation are significant. Specific benefits of fast electricity storage include:

- Management of large renewable energy ramping and management of increased minute-to-minute volatility without degrading system performance and risking interconnection reliability.
- Reduced procurement of very large amounts of regulation, balancing, and reserves from conventional generators, which may be either very expensive or infeasible.
- Avoidance of keeping combustion turbines on at minimum or midpoint power levels to support regulation and load following.
    - Avoids increased greenhouse gas emissions.
    - Avoids higher energy costs due to combustion turbine energy displacing lower cost combined-cycle gas turbines and/or hydroelectric energy.

1.0. Introduction

Renewables integration with the grid has been intensively studied for impacts on production cost, markets, electrical interconnection and grid stability. In the range of dynamic performance from one second to one day, the impact of renewables on frequency response, automatic generation control, and real-time dispatching / load following has largely been studied via statistical and analytic methodologies. These studies have all concluded that there are operational issues raised by the variability and high ramping characteristics of renewables; however, precise quantification of these effects has been elusive. Development of mitigation strategies in terms of market protocols, control algorithms, and the exploitation of new technologies such as electricity storage have lagged, although there has been high interest in the use of electricity storage for system regulation services due to the high prices and market accessibility in the ancillary services market.

1.1. Background and Overview

This research aims to assist policy makers in determining the ability of the California ISO system to meet North American Electric Reliability Corporation (NERC) standards under future Renewables Portfolio Standard (RPS) targets and understanding how the California ISO can best integrate and make use of grid-connected energy storage to meet future system operating needs. To do this, the study uses KEMA's proprietary KERMIT model – a high-fidelity dynamic simulation modeling tool an models the system with various levels of incremental regulation and storage, as renewables penetration increases. The model results provide an assessment of the California power system, California ISO control systems, and real-time markets for different renewable scenarios through the 2020 time horizon. In particular, the study investigates the amounts of regulation required, the use of large-scale, grid-connected electricity storage as an alternative to conventional generation, and the tradeoffs in system reserves and scheduling with these approaches. Ultimately, the research attempts to answer technical questions about system needs and capabilities, such as those posed below:

- How much additional regulation capacity does the system need under 20 percent and 33 percent RPS targets?
- Does that capacity change if resources such as storage are assumed, and in what quantity?
- Can the California ISO system withstand a disturbance control standard event with 20 percent and 33 percent renewable resources, assuming that they displace existing thermal resources?
- What is the storage equivalent of a 100 MW combustion turbine (CT)?

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1.2. Project Objectives

The primary objective of this study is to determine how the California ISO can best integrate and make use of grid connected storage to meet a variety of system needs from ancillary services, including regulation, spinning reserves, automatic governor control response and balancing energy.

The key project objectives were to:

- Calibrate KERMIT simulator to specific conditions of California ISO.
- Working collaboratively with the California ISO, define simulation approach for days and base cases.
- Model current baseline conditions.
- Determine ancillary levels and generator droop requirements for baseline scenarios.
- Define scenarios for electricity storage.
- Run simulation scenarios.
- Assess alternatives for storage duration parameters and Automatic Generation Control (AGC) algorithms to utilize electricity storage.
- Create and validate requirements for AGC algorithms for electricity storage.
- Identify the relative benefits of different levels of electricity storage.
- Develop requirements for storage characteristics.
- Determine the electricity storage equivalent of a 100 MW gas turbine.
- Identify issues and policies to incorporating large amounts of electricity storage on the California grid.
- Prepare a final report and stakeholder presentation that summarizes results.

Though additional resources may help address renewable integration issues, researchers did not consider them in this study. Cost-benefit analysis of potential tools was also out of the scope of this study. However, researchers believe such analysis is should be taken in context with this analysis to fully inform policy decisions. Additional research recommendations, such as further consideration of forecast error, are provided in the report section on recommendations.

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2.0 Project Approach

To conduct the analysis, researchers used the proprietary KEMA Renewable Energy Modeling and Integration Tool (KERMIT) simulation model. The KEMA Simulator (Simulator) is implemented in Matlab Simulink, a powerful dynamic systems modeling tool which is often used for generator interconnection studies. Simulink has an optional *Power Systems Toolbox* that includes models of various wind turbines, inverters, and other electrical apparatus. Detailed simulation was required to investigate the impact on frequency regulation and first contingency stability, resulting from a very high penetration of steady and intermittent renewable resources (up to 7,743 MW in 2012 and 26,234 MW in 2020). The time domain of interest for the regulation and real time dispatch study is in a 1-second to 1-day regime. This regulation / dispatch time domain represents a gap in the existing renewables impact assessments performed to date and requires a detailed dynamic simulation in order to properly understand the impacts of renewable volatility as well as to develop mitigation plans. KERMIT features allow researchers to adjust intermittent resource volatilities and the management of dispatchable renewable resources.

The overall approach, which made use of the KERMIT model, is shown in Figure 1.

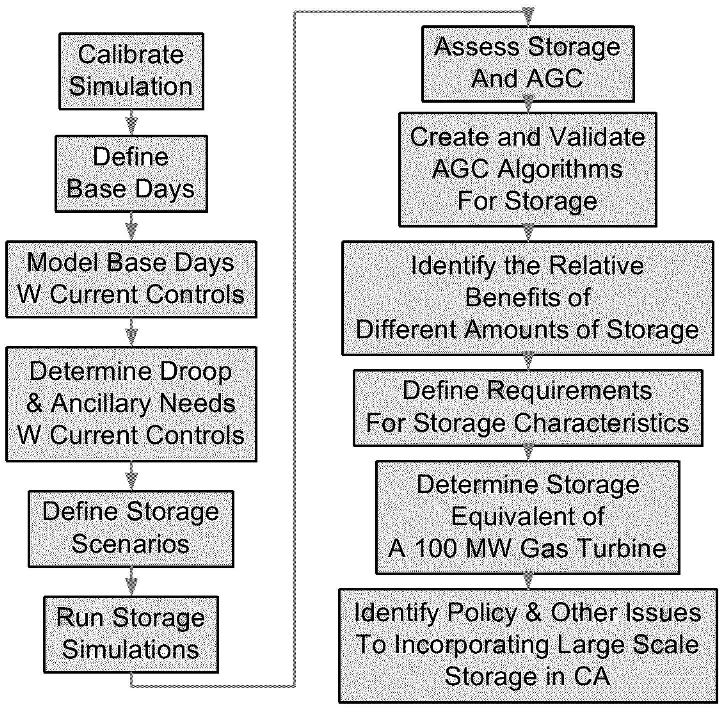

Figure 1. Project steps flow chart

Source: KEMA researchers

The following sections discuss each task carried out to accomplish the project objectives. An introduction to the KERMIT model and an overview the model simplifications and scenarios run follow first.

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2.1. Simulation Summary

Over 500 different simulations were run, examining a variety of system, regulation, and electricity storage parameters against the four days and three future renewable scenarios selected (plus five days for the current year for calibration). Table 2 below summarizes the cases studied.

Table 2. Scenario summary of approaches taken by research team

Source: KEMA researchers

Year / Renewable Scenario	Current	20% RPS	33% RPS Low Estimate	33% RPS High Estimate	Comments
Project Study Element					
Calibration	All days plus one June day*	N/A	N/A	N/A	June used a unit trip to calibrate frequency response of system
Determining Impact of Renewables under Current AGC	All days	All days	All days	All days	February, April, July, October
Determining Levels of Regulation Required to Accommodate Renewables	N/A	All days	All days	All days	Cases studies with AGC values of 400 - 3,200 MW all cases, and 4,000/4,800 MW where required
Determining Levels of Regulation Required to Accommodate Renewables	N/A	None	None	July Day	Cases with 2,400 - 4,000 MW of regulation were modified to keep all CT's on providing regulation
Determining Levels of Regulation Required to Accommodate Renewables	N/A	None	None	All days	Cases were run with 800-3,200 MW of regulation was allocated to a CT and Hydro subset, matching 3,200 MW regulation level
Determining Levels of Storage Required to Accommodate Renewables (Infinite Storage Approach)	N/A	All days	All days	All days	Cases studied with storage levels of 10,000 MW and 12 hr duration
Validating Storage Levels and Determining Durations	N/A	All days	All days	All days	3,000 MW and 4,000 MW cases validated across duration ranges 1 - 4 hrs
Developing and Validating Storage Control Algorithm	N/A	None	None	July Day	Many cases run with various schemes and then with all combinations of PID tunings. Selected controls/tuning were used in subsequent cases
Determining Storage Rate Limit Requirements	N/A	None	None	July Day	Cases run with storage rate limits varying from 2.5 to 100 MW/second. Resulting 10 MW/sec were used in all subsequent cases
Examining Trade-offs of Storage and Regulation	N/A	None	None	All days	Cases with varying combinations of regulation and storage totaling as much as 5,000 MW

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Year / Renewable Scenario	Current	20% RPS	33% RPS Low Estimate	33% RPS High Estimate	Comments
Examining Trade-offs of Storage and Regulation Against Real Time Dispatch Periodicity	N/A	None	None	July Day	Cases with varying combinations of regulation and storage re-run with RTD @ 30 seconds
Examining Trade-offs of Storage and Regulation	N/A	None	None	July Day	Sensitivity analyses of incremental 100 MW regulation or 100 MW storage across range of regulation/storage combinations
Examining Trade-offs of Storage and Regulation	N/A	None	None	July Day	Trade-offs were re-examined with the regulation allocation used above for a subset of CT and hydro units
Droop Investigations	N/A	None	None	July Day	Droop was doubled on all conventional generators and results studied
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3,200 using the Regulation Allocation to only a subset of CT and Hydro units
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3,200 MW with a 110 MW CT added
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3200 MW with 50 and 100 MW storage added
Emissions Impacts	N/A	July Day	July Day	July Day	Emissions from CT and CCGT were calculated across various regulation and storage cases

***All days refers to the four total sample days; one day in each month of February, April, July and October.**

While the research conducted here provides several useful conclusions, the model made simplifications that should be considered further. In particular, literally hundreds of second by second simulation of the California power system were performed for each of the four days and four renewable scenarios developed. These simulations produced the conclusions and results described above. The conclusions and recommended control algorithms and dispatch protocols need to be validated across a much larger sample of days than the four seasonal typical weekdays chosen.

In addition, the study was optimistic in that the impact of large forecast errors for renewable production, especially forecast errors associated with wind production, were not studied. The wind forecast errors assumed in the scheduling and dispatch were not significant. Addressing larger wind power forecast error problems will likely emphasize the benefits of electricity storage compared to conventional generation used for regulation, as these units would have to be kept on for longer periods in order to provide against forecast error.

To develop scenarios, the study observed renewable production for sample days and then scaled these up for the renewable scenarios. This methodology was the only practical approach in the time frame with the data available to the California ISO. As such, it tends to reduce the impact of geographic diversity on the renewable ramping characteristics. While data across the West Coast seems to indicate that this geographic diversity is not as large a factor as might be thought, it will be an important point of discussion needs further analysis. The California ISO is conducting an analysis of the correlations of wind power geographically today. The results of this could be used in another research phase that examines most or all of the days in a year to understand the statistics of system ramping requirements. (The system has to be able to withstand the expected worst case scenario for coincident ramping seasonally. It cannot be designed and operated for averages).

The California ISO did not have available projected hourly schedules for the conventional generation against the different renewable scenarios nor could those have been practically adapted to various reserve and regulation levels studied were they available. As the projected hourly schedules for conventional units become available, these can be iteratively combined with the renewable ramping solutions to further validate and refine both the production costing and dynamic performance conclusions. The limited investigations that the project made of this topic showed that system performance varies with the allocation of regulation to conventional units in ways that vary from one day to the next, not always intuitively apparent. The interaction of energy scheduling, reserve and regulation allocation, and system performance when very high levels of regulation are procured is extremely complex.

The study used assumptions by the California ISO about how much of the state wind power would actually be purchased from wind developers located within the Bonneville Power Administration control area and how much of those resources would be *levelized and balanced* by BPA versus the California ISO. These assumptions will greatly affect outcomes and thus need to be monitored and adjusted as contracts are negotiated. Related to this is the conclusion in the study that the Western Electricity Coordinating Council (WECC) system frequency is not at risk as much as the California ISO Area Control Error (ACE), due to the size of the interconnection. However, if significant additional renewable resource penetration is assumed across the WECC, this result will be optimistic. Therefore, the extension of the study to broader WECC issues (where geographic diversity will have a larger favorable impact) is probably a topic for discussion between the California ISO and WECC.

Finally, the study scope did not include examination of the costs of either greatly increasing procurement of ancillary services or of deploying large amounts of grid connected storage. Such a cost benefit tradeoff requires forward projection of these costs, which is somewhat speculative. These cost benefit tradeoffs can be developed for hypothetical future developments on the economics (including carbon cap and trade) of conventional generation and of storage technologies. A commitment by the state to a single strategy using today's economics will not be as wise as a continuous adoption of strategies as costs and technologies evolve.

This research maintained control area performance at today's levels. It may be that NERC will have to reexamine Control Performance Standard (CPS) criteria in light of higher penetration of

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renewables and establish new goals appropriate to the interconnections and the anticipated geographic diversity of renewables as well as what frequency deviation and tie deviation the interconnection can tolerate. Toward this purpose, a WECC-wide study similar to this one is an advisable next step.

2.2. Modeling Tool

2.2.1. Introduction to KERMIT

The KERMIT model is configured for studying power system frequency behavior over a time horizon of 24 hours. As such, it is well-suited for analysis of pseudo steady-state conditions associated with Automatic Generation Control (AGC) response including non-fault events such as generator trips, sudden load rejection, and volatile renewable resources (e.g., wind) as well as time domain frequency response following short-time transients due to fault clearing events.

Model inputs include data on power plants, wind production, solar production, daily load, generation schedules, interchange schedules, system inertias and interconnection model, and balancing and regulation participation. Parameters for electricity storage are also inputs – power ratings, energy capacity or *duration* of the storage at raged power, efficiencies, and rate limits on the change of power level. Model outputs include ACE, power plant output, area interchange and frequency deviation, real-time dispatch requirements and results, storage power, energy, and saturation, and numerous other dynamic variables. Figure 2 depicts the model inputs and outputs.

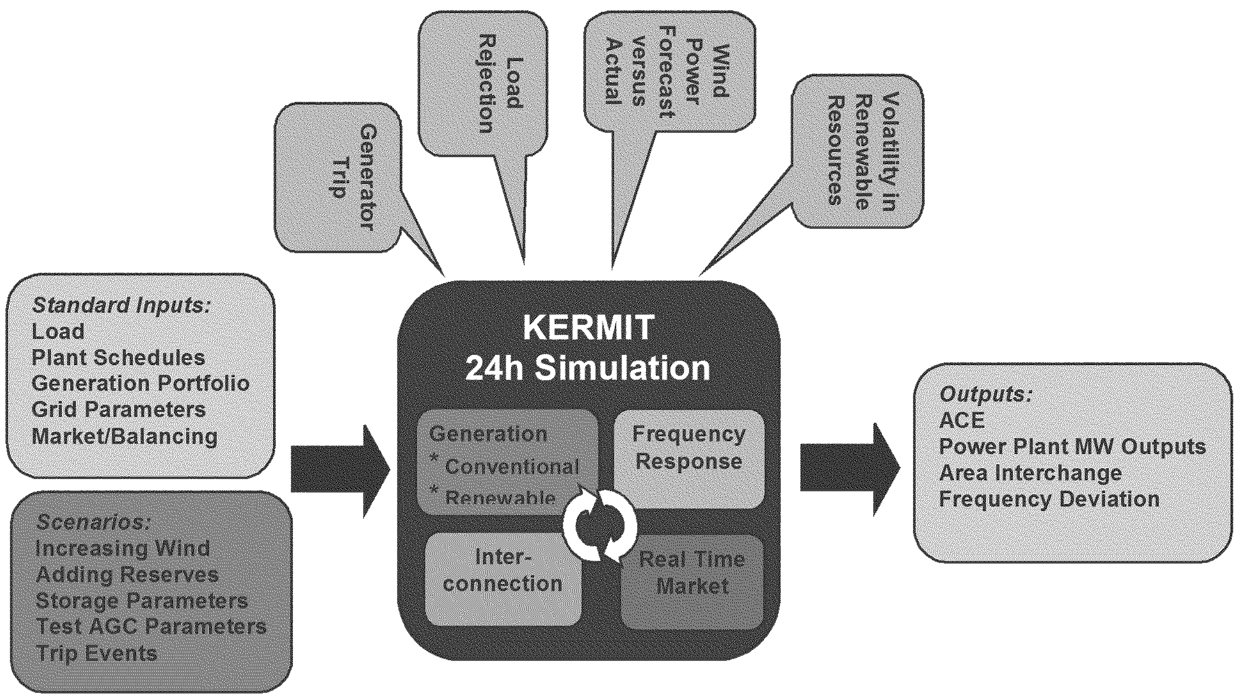

Figure 2. KERMIT model overview
Source: KEMA researchers

Microsoft® Excel-based dashboards allow the creation of comparative analyses of multiple simulations across control variables and the generation of time series plots of key dynamic variables with multiple simulation results co-plotted for easy comparison. Pivot table analysis allows the 3-D plotting of key metrics (such as maximum ACE) across multiple simulations and scenarios. As one simulation will provide a minimum of three or four dynamic plots of interest (maximum of 20+) and a half dozen to dozen key metrics, and there are at least 4 days x 4 renewables scenarios for any selection of variables some mechanism to identify key results, compare them across variables, and present them effectively is essential given the large amount of data created during a project such as this.

The model has a number of useful features aimed at making it effective for analyzing California ISO-specific conditions and different scenarios including:

- Spreadsheet-based data to represent regional power plants.
- Use of actual interchange schedules and load forecasts from typical California ISO data.
- Analysis of dynamic performance of the power system, the AGC, the generation plants, storage devices:
    - Power spectral density analysis, which allows comparison of hour to multi-hour time series (i.e. ACE, plant actual generation, frequency) by mathematical means.
    - Computation of NERC CPS1 performance and statistics.
    - Computation of useful statistics such as max over a time period, averages, and so on.

It is possible to make direct comparisons of different cases to highlight the results of changes from one scenario to the next, such as increased wind development, increased use of regulation for the same scenario, impact of varying levels of storage, impact of different control algorithms and tuning, and comparison of completely different strategies such as storage versus increased ancillaries. These are presented statistically and were turned into Excel pivot tables, or more typically, combined on MATLAB plots to show time series from different cases on the same plots.

2.2.2. Model of California

To account for interactions between the California/Mexico Power Area (CAMX) and other inter-tied WECC regions, researchers modeled the California market as connected with three other areas. These regions are based on the WECC reporting areas and include the Northwest Power Pool (NWPP), the Rocky Mountain Pacific Area (RMPA), and the Arizona, New Mexico, and southern Nevada (AZNMSNV) Power Area. Figure 3 depicts the four WECC regions along with the modeled interconnections. The approach effectively models each external area as another generator with inertia.

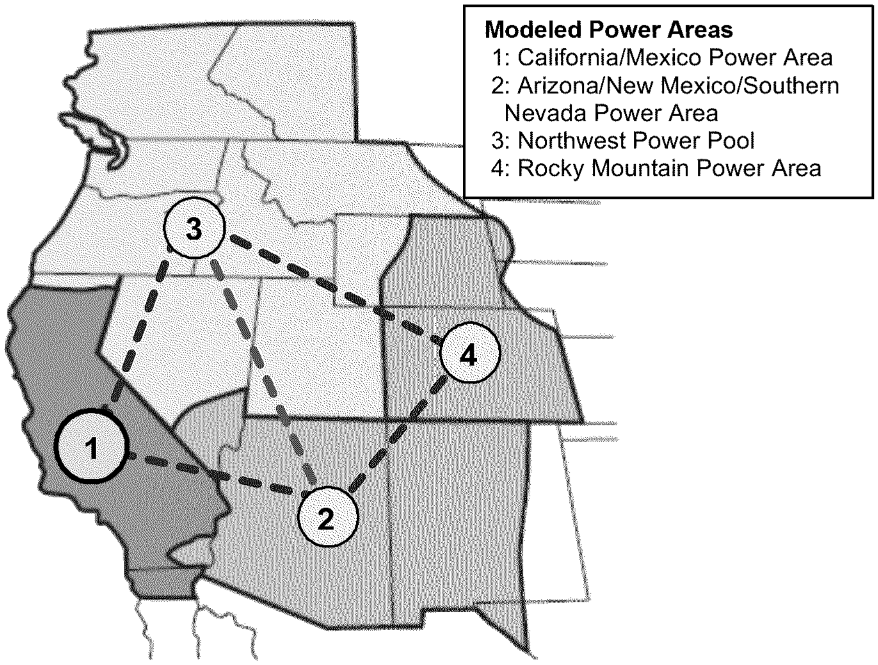

Figure 3. WECC reporting areas and model interconnections

Source: Based on WECC. WECC Reporting Areas. Viewed 2009.

Available on-line: http://www.ferc.gov/market-oversight/mkt-electric/wecc-subregions.pdf

To model the flow between areas, researchers used Equation 1. The calculation redistributes power according to swing dynamics. The phase angle changes as exports, or *production* slows up and speeds down.

Equation 1. Area interconnection

$$\mathrm{FLOW}_{i*j} = P_{ij} \times \sin(\varphi_i - \varphi_j)$$

Where,

FLOW = power flow
P_{ij} = power
φ_i = phase angle
φ_j = phase angle

The California ISO provided researchers with historical wind power, concentrated solar generation, and daily load data in time series, along with hourly generation schedules for individual plants within CAMX for each of the sample days. Researchers modeled four types of conventional generation – nuclear, coal, gas-fired (CT and combined cycle), and hydropower. Information on inertia and droop, load inertia and frequency response and generator time constants were also provided by the California ISO. The project team developed *typical* balancing and regulation participation and balancing market bids for the units. As noted above, all units were assumed to be available for participation in balancing and regulation (except nuclear and miscellaneous smaller units). Researchers used additional data from OSIsoft PI system™ (PI Historian) provided by the California ISO for the sample days, available at a 4-

second time resolution. This data included system frequency, Area Control Error (ACE), interchange schedules, and total system generation for all areas modeled in the analysis.

2.2.3. System Performance Metrics

All balancing authorities are required to meet the NERC Resource and Demand Balancing Performance Standards (BAL Standards)[14]. The BAL Standards are very prescriptive in describing what the Balancing Authorities are required to do to control ACE and system frequency. In this analysis, ACE and frequency deviation are used as metrics of system performance. ACE is a combination of the deviation of frequency from nominal, and the difference between the actual flow out of an area and the scheduled flow. Ideally the ACE should always be zero. Because the load is constantly changing, each utility must constantly change its generation to *chase* the ACE. Automatic generation control (AGC) is used to automatically change generation to keep the ACE within the tolerance band which is annually established for all Balancing Areas. The California ISO calculates ACE based upon tie line flows and frequency and then the AGC module sends control signals out to the generators every couple of seconds. Equation 2 shows the formula used to calculate ACE in the model.

Equation 2. Area control error

ACE = 10 x Bias x Frequency Error + Interchange Deviation

Where,

10	= constant, converts frequency bias setting to MW / Hz
Bias	= frequency bias setting, bias value used by the control area (MW / 0.1 Hz)
Frequency Error	= the difference between actual and scheduled system frequency (Hz)
Interchange Deviation	= the difference between actual and scheduled interchange (MW)

The system frequency error is also available for plotting and statistical analysis, as is the Interchange Deviation. In addition, the *power spectral densities* of the ACE and frequency signals were computed.[15] This is primarily useful in establishing that the base system performance in 2008 and 2009 is consistent between simulated and actual data. Finally, researchers computed statistics on NERC Control Performance Standards (CPS), CPS1 and CPS2.[16] Various statistical measurements of these signals such as absolute maximum are also available.

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[14] The NERC BAL Standards are available on the NERC website at http://www.nerc.com/page.php?cid=2|20

[15] *Power spectral density* is a function that expresses how signal power is distributed with frequency in time series data. It is expressed as power per frequency. Power spectral density analysis is useful for comparing time series data as it illustrates the periodicities observed in oscillatory signals.

[16] Control performance standards are statistical reliability standards specified by NERC, which limit a Balancing Authority's ACE over a specified time period. CPS1 is a statistical measure of ACE variability, and CPS2 is statistical measure of ACE magnitude. Sources include:
1. NERC. "Glossary of Terms Used in Reliability Standards." February 2008. Available on-line at http://www.nerc.com/files/Glossary_12Feb08.pdf
2. NERC. "Control Performance Standards." February 2002. Available on-line at http://www.nerc.com/docs/oc/ps/tutorcps.pdf

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Because renewables ramping effects are as critical as volatility, the performance of the system real time dispatch as simulated is also valuable. The system incremental and decremental real-time MW (INC/DEC) and the marginal clearing price (MCP) are also computed, plotted, and analyzed. The KERMIT model uses a simple real time dispatch analogous to the former California ISO RTD algorithm rather than a multi-hour commitment algorithm. This was deemed sufficient by the California ISO for the purpose of this project.

2.3. Task 1. Calibrate Simulation

To obtain validity in model predictions, the team began by calibrating the simulation using 2008 and 2009 data. This process entailed adjusting model parameters until simulation output matched actual historical 2008 and 2009 performance data. While results were not intended to be exact, researchers harmonized certain basic system characteristics so that results were representative of today's market and system performance. In particular, researchers looked for realistic AGC behavior, fidelity in matching unit trip response and reasonable match to real-time prices. Data used to match these characteristics included:

- Area Control Error
- System frequency data
- Real-time price data.

Actual generator bid data is confidential and therefore was not available to the research team. To gauge real-time price outputs, researchers created synthetic bid data, which was subsequently reviewed and accepted by California ISO as a suitable proxy. Researchers assigned a typical bid number to units participating in balancing and validated that day-ahead, market-clearing prices fit within expected results.

The calibration process was done in two steps. The first step focused on power grid dynamics while the second step focused on primary and secondary controls. Figure 4 is a schematic of the calibration process, with the areas of focus for steps 1 and 2 each outlined in the respective boxes.

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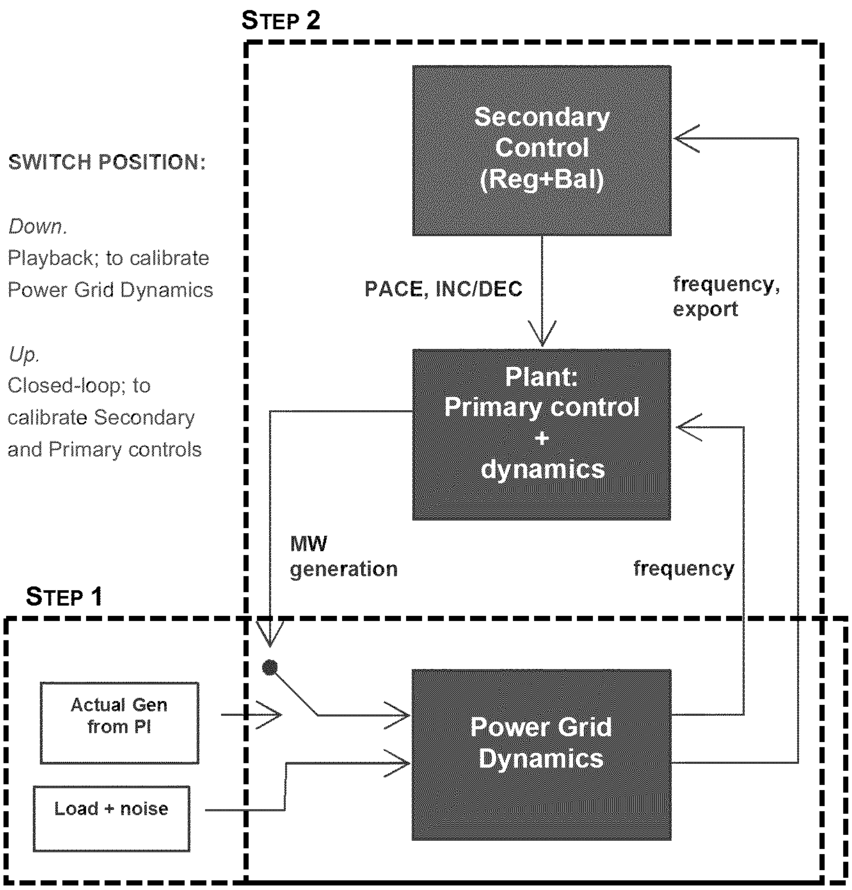

Figure 4. Calibration process
Source: California ISO

The goal of step 1 was to adjust KERMIT model inputs to produce interchange and frequency signals which match the behavior of the historical data. Researchers inputted actual recorded generation data and used pre-processing to *recover* load and noise from available data. In particular, researchers solved the power flow for the four-area system shown in Equation 1 at appropriate time intervals using injection data from PI Historian. From this power flow solution, researchers computed the frequency of each area throughout the sample day. Reversing the *swing dynamics* using second-order differential equations allowed recovery of the load and noise values.

The goal of step 2 was to calibrate the full model, including the modeling of primary and secondary generating plant controls. Here, researchers ran the model as a closed loop simulation. Researchers fed the model's primary and secondary controls with the validated frequency and interchange output from step 1. Researchers then examined the model's ability to produce a *MW generation* signal that matched that of historical data from PI Historian.

One issue encountered in the calibration process was that the model initially produced noisier ACE than real world (i.e., it crossed the zero axis more often). Researchers tuned the model by adjusting load noise to best match the historical ACE as best as possible (e.g., match frequency of zero ACE crossings, bandwidth). This tuning involved substituting load noise recovered from the PI Historian data in place of applying random noise.

In the absence of real bid data for the sample days, the researchers created synthetic bid data that was reviewed and accepted by California ISO as a suitable proxy. This data was required for the operation of the real time dispatch. However, identifying which unit was used to provide incremental MW by the dispatch is not significant to this study. It is the general response of classes of units that affects system performance and ramping and typical dispatch results were the objective.

2.4. Task 2. Define Base Days

As the basis for simulating future conditions in 2012 and 2020, researchers worked with the California ISO to select four days to model for assessing future renewables' impact. Additionally, one 2009 day with a major unit trip was used to calibrate system frequency response to a large disturbance. Simulation of these selected days under future scenarios demonstrates the impact of renewables integration on AGC performance and balancing costs. Thus, the simulation days chosen by researchers, in conjunction with the California ISO, include four typical days, one in each of the four seasons, and one event day.

Data for each base day included four second system load and system generation data, photovoltaic and concentrated solar production, wind production, interchange data, frequency, ACE and AGC from the 2008 and 2009 time period. To develop 2012 and 2020 scenarios, researchers adjusted base day time series data to incorporate anticipated load growth and renewable resource development. Anticipated load growth for 2012 and 2020 were derived using the latest California Energy Commission load forecast projections[17]. Assumptions about renewable resource development were made using the latest information on what new generation is in *queue* for California ISO interconnection planning and the CPUC / E3 study on 33 percent renewables. As there is uncertainty about renewable resource development for 2020, researchers prepared a *low* 2020 scenario and *high* 2020 scenario.

In selecting four of the base days, researchers intended to capture the seasonal variation of renewable production. In particular, the model runs over a 24-hour time period. By selecting multiple base days, the analysis assesses typical renewable output profiles for those times of the year. The four seasonal days selected were Wednesday July 9, 2008; Monday, October 20, 2008; Monday, February 9, 2009; and Sunday, April 12, 2009.[18]

An additional base day illustrated system performance where a large generating unit tripped. This allowed researchers to gauge system trip response under current conditions (to help calibrate the model), as well as to consider a future system performance where larger amounts renewable production are on-line and a traditional generating unit trips. The event day selected

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[17] California Energy Commission. *California Energy Demand 2010-2020 Staff Revised Forecast*. 2009. Available on-line at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/

[18] Some of the four seasonal days also had disturbances. However, these were relatively minor.

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was June 5, 2008. On that day, the California ISO SONGS Unit Number 2 relayed while carrying 1,095 MW. System frequency deviated from 59.998 to 59.869 and recovered to 59.924 by governor action.

2.5. Task 3. Model Study Days for 20 Percent and 33 Percent Renewables With Current Controls

2.5.1. Introduction

Once researchers calibrated the model to best match the 2008 and 2009 historical data and system performance, researchers then modeled the study days for 20 percent renewable and 33 percent renewable scenarios. Because no forecast data was available at the detail needed for modeling, researchers scaled up the existing time series for production from the renewable resources to reflect projected capacities in 2012 and 2020 to simulate future scenarios. This section describes characteristics of the study days selected for the analysis and illustrates the projection to future years with data from July. Data for all days is available in the appendix.

2.5.2. Load

Future load estimates were derived from the preliminary demand and energy forecast of the *2009 Integrated Energy Policy Report (IEPR)*, shown in Figure 5.

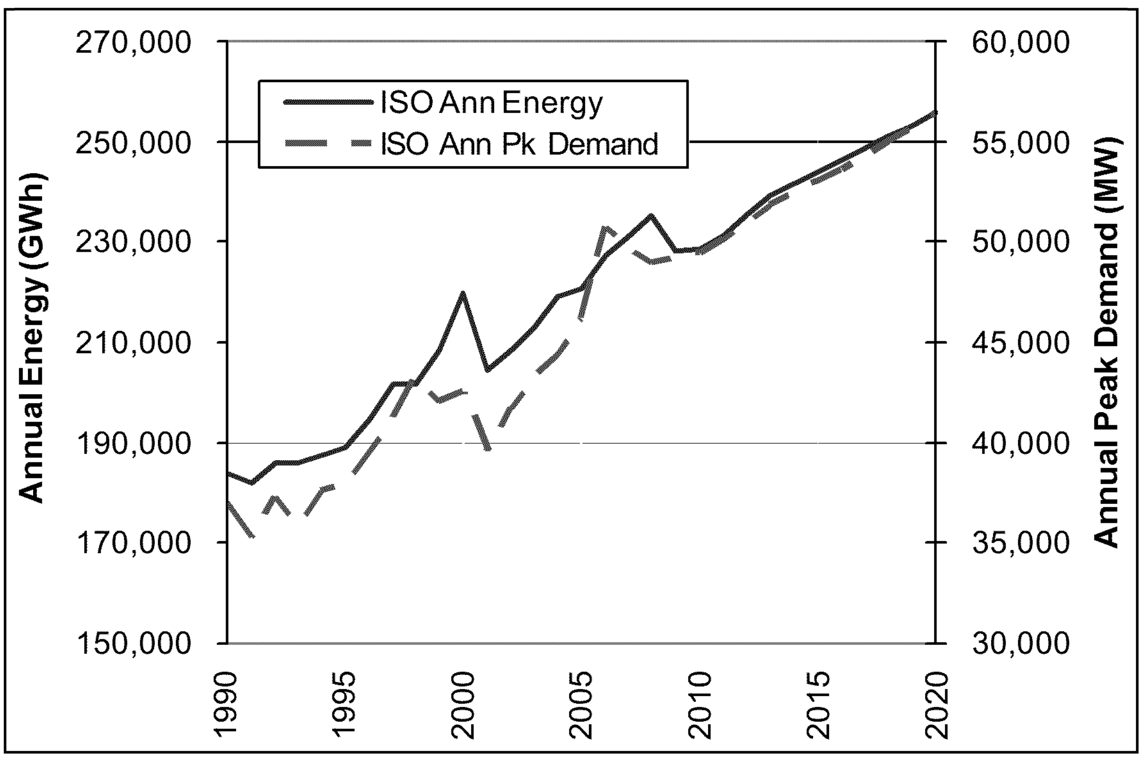

Figure 5. California Energy Commission preliminary demand and energy forecast to 2020
Source: *IEPR 2009*

To derive load size in 2012 and 2020, researchers applied the same percentage increase in load from the *IEPR* forecast to the base day load amounts. As illustrated in Figure 6, growth in the peak load through 2020 is forecast at approximately 1.2 percent per year.

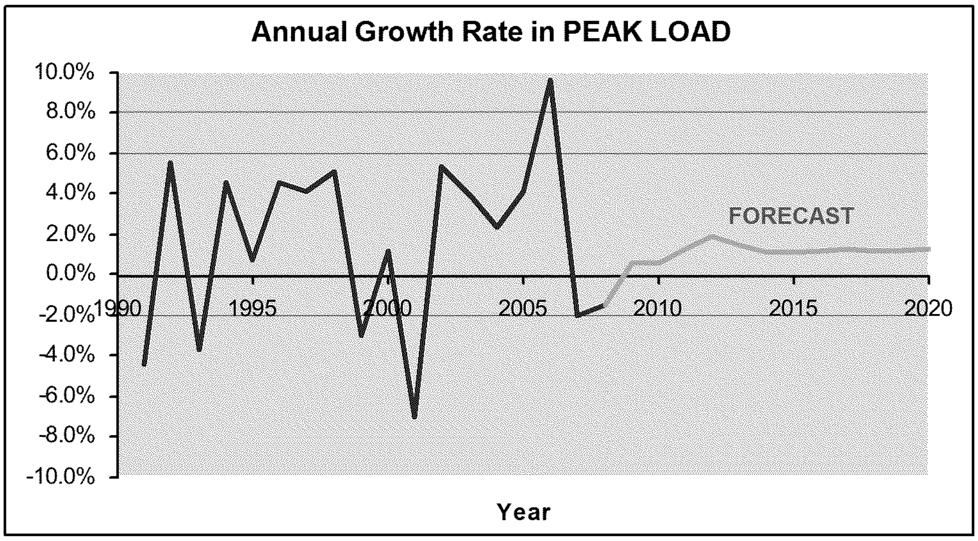

Figure 6. Annual growth rate in forecasted peak load

Source: *IEPR 2009*

To account for variability in load while aligning future load estimates with projections of load growth, researchers scaled up the base day time series by a factor of 1.049 percent for 2012 and 1.127 for 2020. Figure 7 illustrates the daily load variations for the 2009 base days.

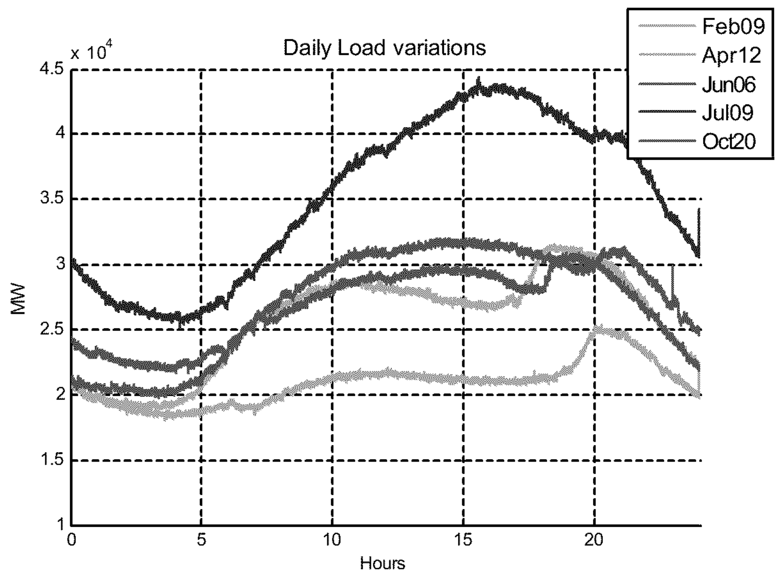

Figure 7. Daily load variation for each of the base days

Source: California ISO data and model outputs, respectively

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2.5.3. Renewable Generation

To model future generation profiles of renewable energy, researchers scaled base day time series to reflect projected capacities in 2012 and 2020. Researchers modeled distributed renewable generation in the aggregate. Table 3 shows the generation capacities used in the 2012 and 2020 cases, as compared to 2009 amounts, for photovoltaic (PV), concentrated solar generation (CS), and wind power. These values were provided to the research team by the California ISO, based on projects currently in the interconnection queue which would realize the 20 to 33 percent renewable portfolio standard level. Between 2009 and the high case for 2020, wind generation nameplate capacity increases by over fourfold.[19] Concentrated solar generation increases by a factor of 25 over the same time period.

Table 3. Generation Capacity by Type (MW)

Year	2009	2012	2020 low estimate	2020 high estimate
PV	400	830	3,234	3,234
CS	400	996	7,297	10,000
Wind	3,000	5,917	10,972	13,000

Source: model outputs

Wind Power

Given time series of past wind production and the expected wind generation capacity from Table 3, researchers developed future wind energy production time series with scaling. Researchers used two sets of time series wind data from the NP15 EZ Gen Hub and the SP15 EZ Gen Hub, depicted in Figure 8.

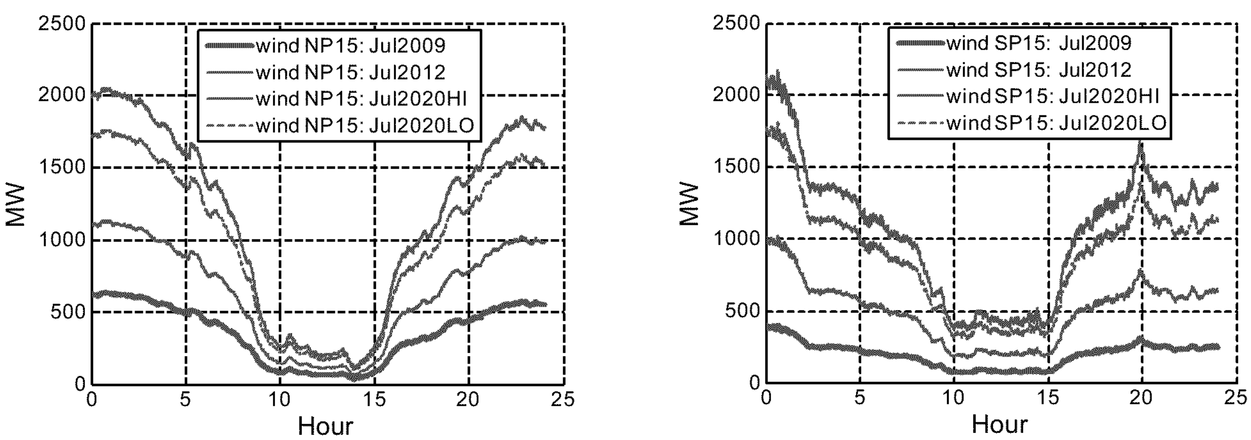

Figure 8. Regional wind production data

Source: model outputs

[19] While the model uses nameplate capacity projections to forecast wind production capacity, the time series data from the base days determines how much capacity is ultimately used for energy production.

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An estimated 3,000 MW capacity of the future wind power resource is anticipated to come from wind farms located with the Bonneville Power Administration (BPA) control area. The California ISO determined that the project should use the following assumptions about these resources:

- Their daily production would parallel the NP 15 production patterns. (This was based on comparisons of some representative wind productions available.)
- Fifty percent of this wind would be balanced by BPA such that imported power would be levelized to the California ISO control area.

The wind power simulated reflected these assumptions.

Concentrated Solar Generation

Time series data for typical concentrated solar generating units was available from the California ISO. Quite often, CS generation is used in conjunction with gas firing to extend its production. The data used here contains that assumption. This reduces the time between the fall off of concentrated solar production and the ramp-up of wind production by varying amounts according to day and season.

Researchers scaled up the time series data to match future expected capacities across the scenarios. These then served as scenario inputs for the model. Figure 9 illustrate the concentrated solar production time series for the July days.

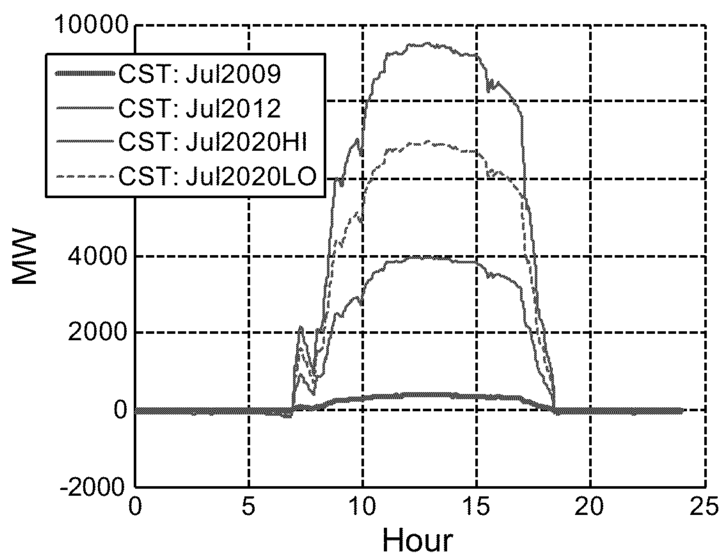

Figure 9. Concentrated solar generation time series for July scenarios

Source: model outputs

Photovoltaic

Because limited public data was available, researchers simulated PV generation to develop a PV time series for the KERMIT model. Direct inputs for this PV model are temperature and solar intensity time series data obtained from NOAA. Researchers obtained the time series for the base and study days, using a weather station site near Sacramento. Indirect inputs are related to panel characteristics such as electrical and tilt and details of the surrounding environment, such as clouds and albedo.[20] A random model was used to represent cloud movement. The resulting PV time series data was scaled up for 2012 and 2020, based on the PV capacities expectations for these years, listed in Table 3, above. Figure 10 depicts the time 2012 and 2020 time series for the July day. These simulated photovoltaic time series align well with other estimates of California PV studies.

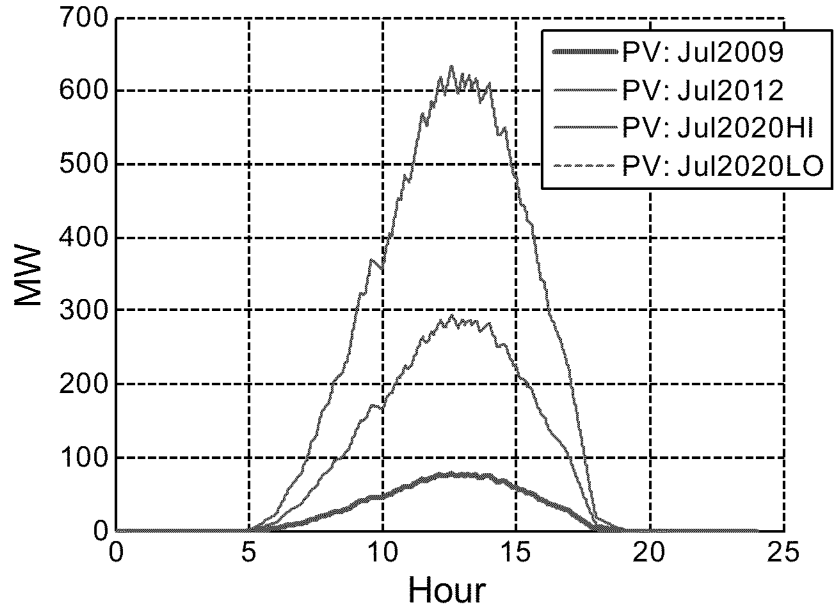

Figure 10. Time series of photovoltaic production for July scenarios
Source: model outputs

2.5.4. Forecast Error

Researchers constructed a time series wind forecast based on actual historical wind data provided by the California ISO. Both the approximated wind forecast error and actual wind production are used in the simulator. Figure 11 depicts this approximated forecast error for July 2009.

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[20] The term albedo (Latin for white) is commonly used to applied to the overall average reflection coefficient of an object.

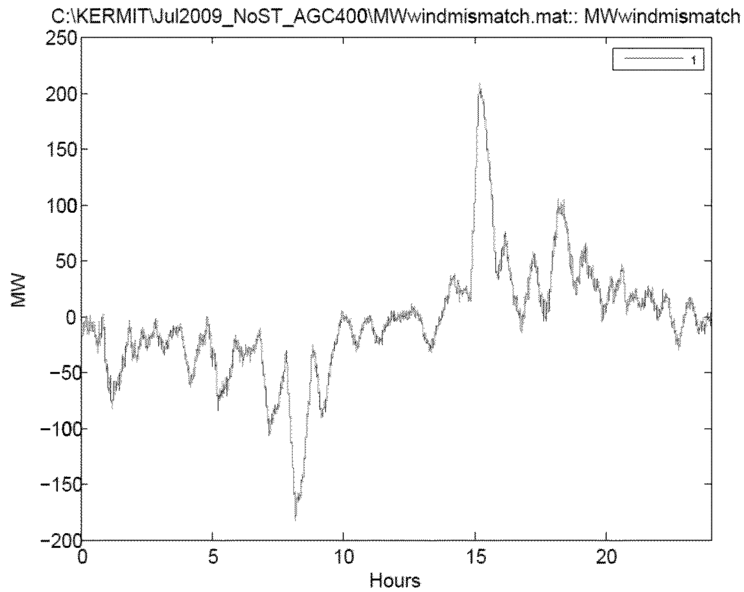

Figure 11. Wind forecast error for July 2009 scenario
Source: model output

This project scope did not include assessing wind power forecast accuracy nor projections of how this might improve in the 2009 to 2020 time horizon. The actual forecast for the representative days in 2009 was used and scaled up along with the production for the 2012 and 2020 scenarios. The methodology of the project assumed therefore that the hourly scheduling for conventional units matched relatively accurate wind forecasts. For the purposes of determining balancing and regulation requirements, and the utilization of storage, in order to accommodate expected renewable resource production, this is valid. It does not address the potential larger balancing requirement and impact on scheduling reserves, which might be necessary to manage large wind forecast errors.

2.5.5. Conventional Unit De-commitment Approach

The original project plan envisioned that energy production schedules for conventional units for the 2012 and 2020 scenarios, schedules that would reflect the higher levels of energy from renewable generation, would be available. However, these production schedules were not available in the time frame required for this study. Using the 2009 schedules for conventional units would not have been realistic as they would not have factored in load growth nor the displacement of conventional generation as a result of high renewable production. Therefore, a different strategy had to be created to develop the required generation schedules for the 2012 and 2020 study days.

The researchers developed a future unit commitment schedules by using the 2009 schedule data and factoring in the significant increase in renewable generation for the future year cases. This included adjustments to the 2009 generation schedules in order to de-commit thermal units appropriately to make room for the energy from the additional renewable generation. This entailed comparing the total of renewable generation plus the conventional generation unit commitment schedule by hour vs. the hourly load projection, then de-committing thermal units to match the hourly load. This de-commit process first shut off combustion turbines (CTs) by merit order, followed by combined-cycle gas turbine plants (CCGTs) in merit order as needed until total hourly generation matched load.

For the purpose of the 2012 and 2020 cases, hourly interchange assumptions matched the 2009 hourly interchange data except for adjustments related to new imports of wind resources anticipated from BPA, which were added on top of the 2009 hourly interchange schedules.

These measures produced unit schedules for the conventional units that were reasonably consistent with the wind and solar production for the study days as scenarios for 2012 and 2020. Planned generating unit retirements and planned unit repowering due to once-through cooling requirements and other changes in unit capacity or rate limit performance were also factored into the 2012 and 2020 scenarios so as to have as accurate a picture of the conventional fleet as possible.

Figure 12 illustrates the de-commitment model used by the researchers. The unit retirements and capacity changes plus the typical adjusted unit schedules for the base and study days are contained in the appendix.

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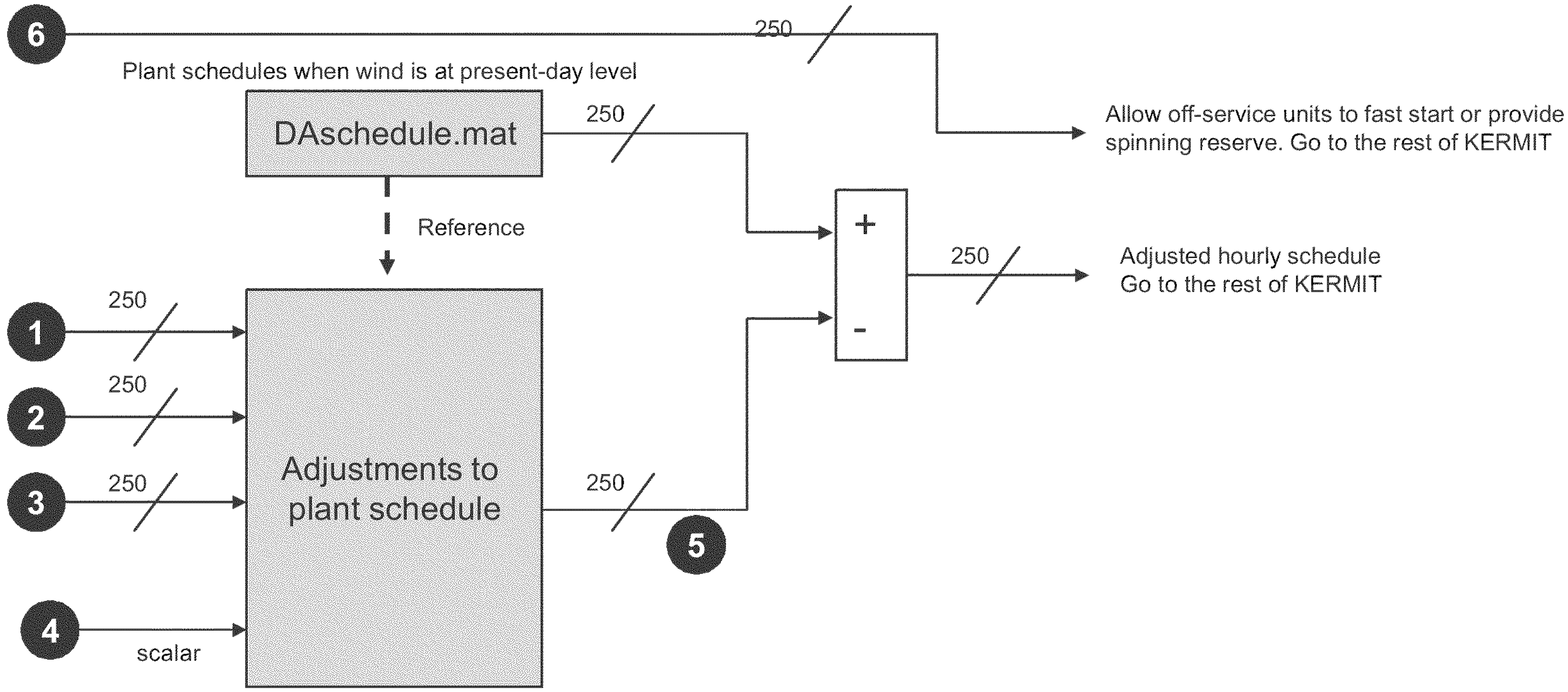

Figure 12. De-commitment model representation used by researchers

Source: KEMA researchers' model

2.5.6. Total Renewable Production and Conventional Unit Production

Figure 13 compares the total assumed renewable production between 2009 and 2020 High. Figure 14 shows the same for April. On both days, the 2012 and 2020 load shapes for wind and solar are comparable to the 2009 cases. However, they are scaled up to match forecast projections. The hourly profile of total renewable production is heavily dependent on the relationship of wind to solar. In all cases, total wind production ramps down in the morning as solar ramps up and ramps up in the evening as solar ramps down. However, the extent of ramping varies. As noted earlier, the California ISO modified the observed concentrated solar production for each day to simulate the use of gas firing to extend the concentrated solar production an extra two hours. This reduces the time between the fall off of concentrated solar production and the ramp up of wind production by varying amounts according to day and season.

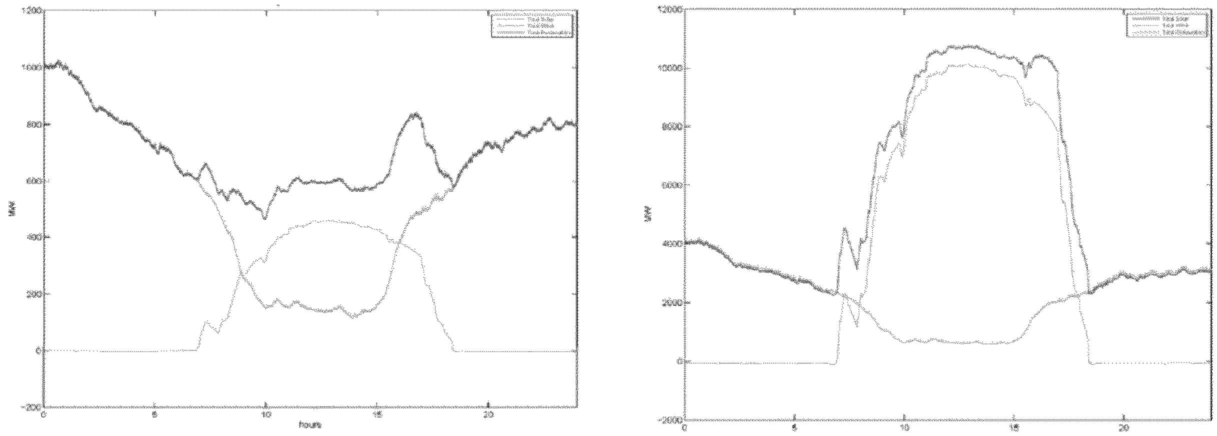

Figure 13. Renewables production for July 2009 and July 2020 scenarios

Source: model outputs

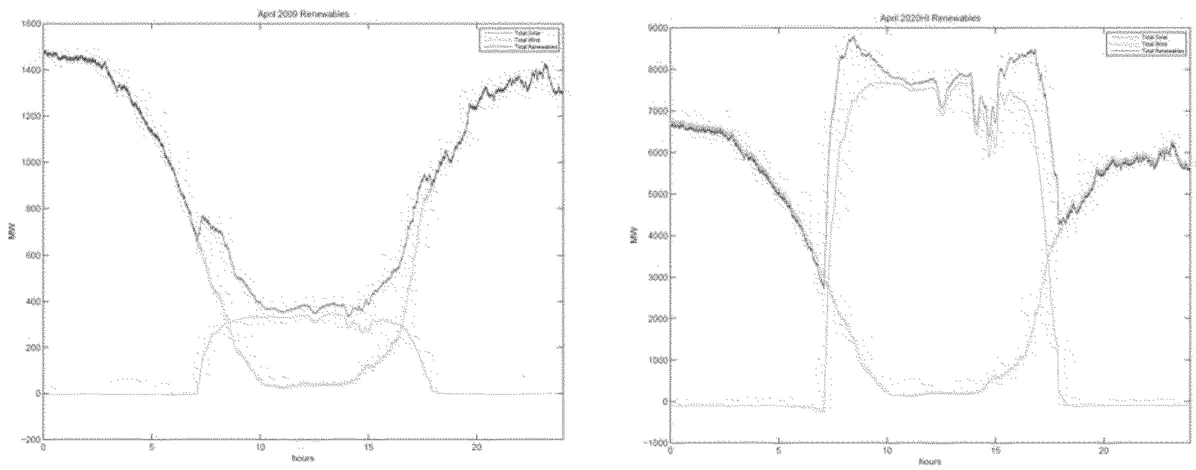

Figure 14. Renewables production for April 2009 and April 2020 scenarios

Source: model outputs

The total renewable production by type and the conventional unit production by type are shown in Figure 15 for the July days simulated in the 2012 and 2020 Low and High scenarios. (The renewable production for all days is contained in the appendix). Across the scenarios the generation portfolio changes, with wind power and solar PV generation increasing in share and combustion turbines and combined cycle generation decreasing. Hydropower and generation imports experience more minor changes in total share, with scheduling being the predominant difference. The differences between 2020 High and 2020 Low cases are less pronounced, but the types of portfolio changes are similar.

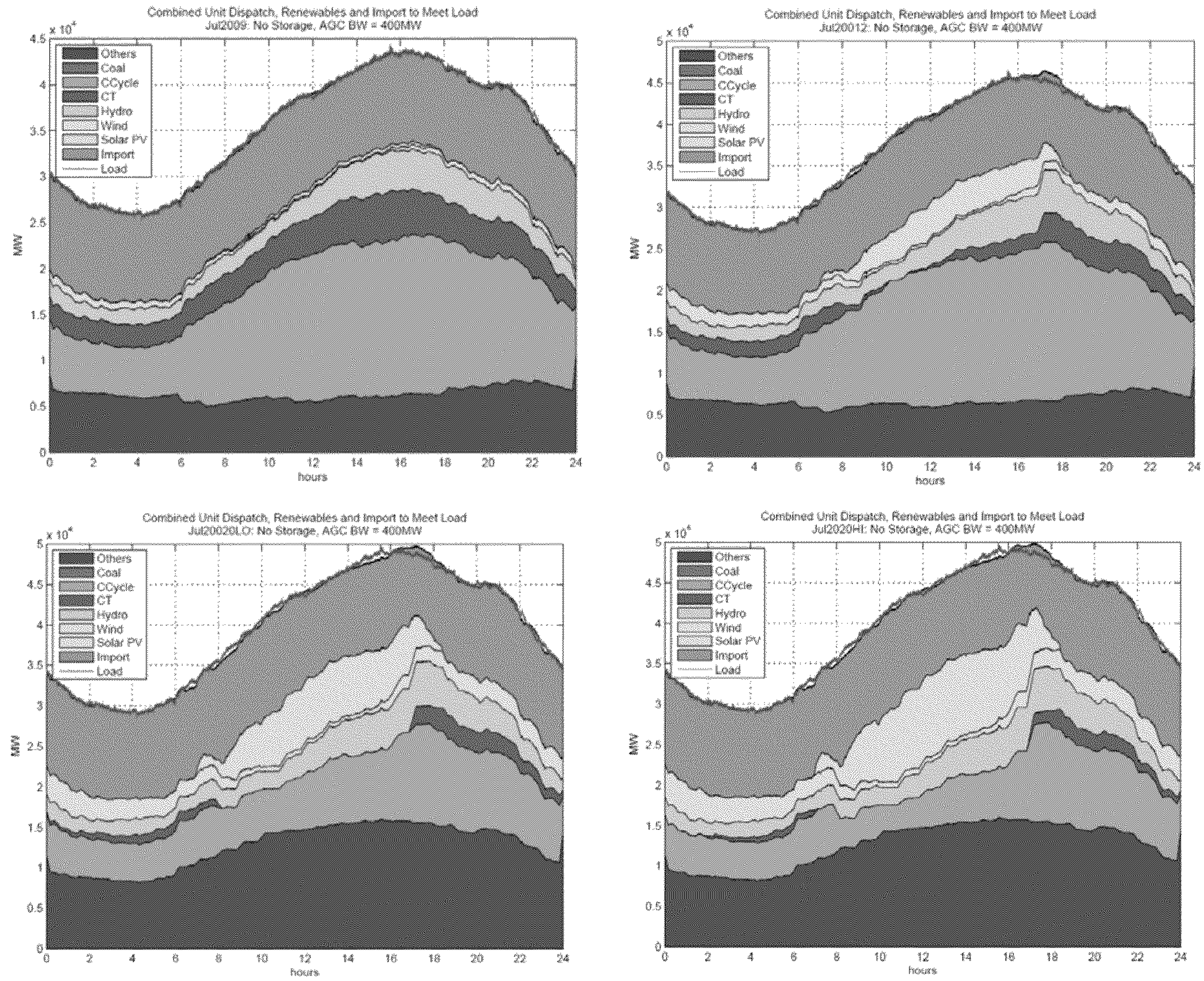

Figure 15. Generation by type and load for July days in 2009, 2012, and 2020
Source: model outputs

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2.6. Task 4. Determine Droop and Ancillary Needs With Current Controls

2.6.1. Ancillary Needs

In 2008, the California ISO required about 390 MW of upward AGC capability and 360 MW of downward AGC capability to adequately regulate system frequency. It runs a separate market for positive and negative regulating service, so the amounts of these ancillaries that are procured may be asymmetric. The addition of large amounts of wind and solar renewables, which have rapid and uncontrolled ramp rates, can be expected to increase regulation requirements. The researchers assessed the amounts of regulation needed in future RPS scenarios and determined the impact on system performance with different levels of regulation. For study purposes, the researchers assumed an equal positive and negative (e.g., symmetrical) regulating requirement. Thus, the report simply refers to regulation bandwidth or AGC bandwidth (where a *BW* of *X* MW infers procurement of AGC for a range of +X to -X).

Under typical circumstances the California ISO's frequency regulation needs are achieved today by having about a dozen generators on AGC control in order to meet its WECC/NERC frequency performance obligations. However, under high renewable scenarios, the number of units needed on AGC may need to be many times greater. In addition to AGC service, the California ISO also operates a balancing energy market to respond to deviations between the scheduled and actual level of generation output on an hour-to-hour basis in real-time operation. Although balancing energy responds at a slower rate than AGC, the operation of both of these markets overlap significantly, and they both impact the California ISO's overall frequency and ACE performance. Therefore, both AGC and balancing energy needs are examined in this study.

After establishing a baseline AGC performance based on historical data, the research analyzed the extent to which renewables might degrade the performance of system frequency regulation in the 2012 to 2020 time frame. Researches hypothesized changes in the future regulation levels to be procured through the ancillary services markets and investigates the impact of different levels via simulation of system frequency response using the KERMIT model. The goal was to determine acceptable levels of AGC performance and balancing energy requirements under RPS levels in 2012 and 2020.

The current California ISO AGC bandwidth was assumed to be ±400 MW. A key unknown is how regulation will be provided for renewables to be imported by the California ISO from BPA. For the purpose of this study, it was assumed that 50 percent of that regulation responsibility would be provided by BPA and 50 percent by the California ISO.

Future regulation bandwidth requirements were determined by increasing the regulation bandwidth in increments until ACE and frequency performance for the 2012 and 2020 scenarios were consistent with 2009 performance. The 2020 High scenario required very large amounts of regulation. Consequently, in order to ensure that units with higher ramp rates were available to provide sufficient regulation, some additional cases were run where all the CTs and hydro units

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remained on at 20 percent minimum so as to have the required regulation bandwidth available. (Otherwise regulation duty would fall on CCGT and other slower units, degrading performance).

2.6.2. Governor Droop Settings

Researchers also examined the potential impact of adjustments to governor droop settings. Governor droop setting is a measure of the automatic increase (governor response) in the energy output of a generating unit measured in MWs /0.1Hz due to a frequency deviation on the system and expressed as a percentage of typical system frequency. The research team simulated cases where droop on conventional units was changed from today's standard of 5 percent to double that amount, 10 percent.

2.6.3. Real-Time Dispatch

System reserves, real-time / balancing energy requirements, and AGC bandwidth are all interlinked. In order for the system to have large amounts of AGC bandwidth available, it must have corresponding amounts of reserves available from the generator schedules. Determination of AGC bandwidth and balancing energy requirements develops the requirements for reserves that would be used in developing the hourly schedules for conventional units.

The real-time dispatch algorithm in KERMIT approximates the former balancing energy market real-time dispatch (RTD). It is a straightforward auction model of increment and decrement bids from participating plants. For the purposes of this project, the RTD market is quite deep – several thousand MW of available increment and decrement. The algorithm accepts as input a MW required figure, which is the sum of total supply – all conventional and renewable generation, actual imports, plus actual storage power output. It subtracts from these the total import and generation schedule to arrive at total incremental or decremental MW required. It can also add the filtered ACE in as a requirement as well. Thus, RTD serves to reallocate the total generation and error to the generators on a bid economics basis. RTD nominally runs every five minutes but can be run at any frequency.

2.7. Tasks 5 Through 7. Define Storage Scenarios and Run Simulation and Assess Storage and AGC

The goal of this task was to define storage facility scenarios above and beyond the existing pumped storage facilities that exist in California (e.g., Helms and Castaic plants). The researchers began by using an infinite storage capacity model in order to see how much would be used by the system for each of the modeled days in 2012 and 2020. For this purpose *infinite storage* was defined as 10,000 MW with a 12-hour discharge duration. The amount of power used from this stored energy source used by the model in 2012 and 2020 provides an indication of how much storage power capacity is required in various RPS and AGC scenarios. The energy used (charging or discharging) during major ramping periods is an indication of the energy needed.

The maximum power utilized from the *infinite* storage was used to develop the approximate sizes of storage to be used as *required* for validation. The approximate duration of storage was estimated by examining the time that the storage power from the infinite unit went between

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zero crossings as an approximation. From the plots of *infinite* storage developed for the scenarios, some approximate estimates of required configurations in each day/scenario were developed. For simplicity these configurations were reduced to round numbers; e.g. *two hour* durations. This methodology avoided iterating through numerous simulations with different storage levels to identify required needs.

In addition, the researchers examined the impact of increased regulation amounts on the system. In particular, researchers ran the scenarios with multiple amounts of storage to observe the impact on system metrics. To observe large amounts of regulation, researchers constrained generation schedules to maintain combustion turbines *on* during the day and available for regulation service so that these very high levels of regulation could be realistically provided.

2.8. Task 8. Create and Validate AGC Algorithm for Storage

Automatic Governor Control (AGC) control algorithms for system storage that had been developed in prior studies proved inadequate for the ramping problem, even though they were sufficient in *normal* conditions. This had to be rectified before storage requirements could be developed, both for the conventional generators and for storage. Therefore, the next focus was to assess how to most effectively integrate storage with system operations and real-time market operations. This included testing of improvements to the AGC. When significant amounts of both storage and conventional regulation are present, the AGC has to be able to use both effectively considering the relative performance characteristics of each. The development of an algorithm to accomplish this was the subject of Task 8.

It was observed during major ramping activity that the storage system failed to respond fully to the ramp even though the power capacity of the system should have been adequate. This is because the AGC relies primarily on a *proportional* where the control signal sent out (regulation) is proportional, i.e. linearly related, to the error signal (ACE). Some AGCs use an integral term as well in order to ensure that ACE returns to zero frequently; it is not known if the California ISO AGC has this feature (although some older documentation indicates not). The project therefore explored different control schemes for using the storage, including the use of a PID controller. Different control schemes were explored and different tunings used until an acceptable scheme was found.

2.9. Task 9. Identify the Relative Benefits of Different Amounts of Storage

After developing an algorithm to properly control the storage devices, researchers examined the benefits of various capacities and durations of storage. In particular, researchers calculated system metrics for varying amounts and durations of storage to see the maximum amounts necessary to return to today's performance levels.

The ultimate objective of using storage for regulation and ramping may have to be determined in light of several different metrics:

- Maximum frequency deviation (a reliability criterion)
- Maximum ACE (a NERC criterion)
- Maximum interchange error (which could become a reliability or economic criteria if events result in overloads and/or re-dispatch to avoid prolonged overloads under renewable ramping) or
- Avoiding the need for conventional units scheduled on simply to provide regulation and ramping (economics and emissions).

In other words, ACE excursions of over 1,000 MW may be tolerable if they are restored promptly. This study used as an objective the maintenance of overall performance similar to today and did not explore whether in the future different system performance criteria can be established.

2.10. Task 10. Define Requirements for Storage Characteristics

Different storage technologies exhibit different characteristics in terms of the cost of energy storage capacity and the relative cost and performance of rate of charge, and also the charging-discharging losses incurred. These parameters are usually stated as duration, power capacity, and efficiency.

Other storage parameters of interest include efficiency in the charge / discharge cycle, self-discharge, rate limit, and depth of discharge capability. Some technologies cannot withstand frequent deep discharge (traditional lead acid batteries, for instance). Others are more or less *lossy* (prone to energy dissipation) and inefficient. Some have different charge and discharge rates. The storage systems studied had efficiencies of 95 percent, which is the best achievable from advanced lithium-ion systems; where the inverter electronics and step-up transformer consume the 5 percent. Lesser efficiencies do not reduce regulation or ramping performance but adversely affect economics due to losses in the charge-discharge cycle. This was not considered a factor in system performance.

An inability to withstand deep discharge cycles means, in effect, that additional capacity needs to be installed in order to provide effective capacity. Thus, if a technology were deployed that were limited to 50 percent discharge, it would be necessary to provide twice the capacity of a technology of one that had no such limit. Thus, a storage system with a 50 percent limit would in effect need 12,000 MWh of storage where the study had determined that a 3,000 MW, 2-hour unit was required.

The rate limit of the storage system, however, is a performance concern for this study. The *infinite* storage systems and the sizes validated had no rate limit. That is, it was assumed that the power electronics could change from full discharge power to full charge power in less than one second and that the storage media could withstand this. As a practical matter, this performance level is far greater than required. It is not clear to the researchers that the storage industry understands the impact of frequent power level changes at a high rate limit as this is not normally a requirement.

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The rate limit performance requirements were determined by imposing decreasing rate limits on the rate of power input/output of the storage devices until system performance degraded significantly. This allowed the development of a sensitivity curve of system performance versus storage rate limit for the selected sizes of storage systems.

The storage systems first studied with no effective rate limit in effect have storage power output equal to desired power control signal input. Once a rate limit is imposed, the AGC control algorithm controlling the storage has to be adjusted to maintain performance of the overall system. This was assessed by varying the gains of the PID controller (including a derivative term to prevent integral overshoot).

2.11. Task 11. Determine Storage Equivalent of a 100 MW Gas Turbine

Researchers examined the best storage configuration that could act in the same way as a 100 MW gas combustion turbine (CT) in terms of levelizing variable wind output. To determine the storage equivalent of a 100 MW CT, a definition of the context of the comparison must be made. Storage is not an equivalent, of course, in terms of energy production. The context of this study is system regulation and ramping for managing high renewables.

Without performing any simulations, it is possible to do a simple analysis. A 100 MW CT is theoretically capable of at most 50 MW of up and 50 MW of down regulation. (In practice, the amount is less as the unit cannot be ramped below a minimum level without shutting it down.) A 100 MW storage system is theoretically capable of 100 MW up and down regulation, twice the regulation capability of the CT unit.[21]

The energy cost of each technology is quite different. If the regulation signal has zero bias or constant offset in a given hour, the CT will have a 50 MWh cost to provide its 50 MW of regulation. The storage system will have an energy cost associated with its losses in charging and discharging plus any parasitic losses, such as internal self-discharge losses. The charging and discharging efficiencies dominate the losses for most storage technologies, ranging from as much as 30 percent (such as with pumped hydro, Compressed Air Energy Storage (CAES), and some batteries) to 5 to 7 percent (such as with advanced Li-ion batteries, where the efficiency of the power electronics and step-up transformer are the source of the bulk of the losses).[22]

[21] This assumes that the storage system has a duration capable of fulfilling the regulation for at least the protocol minimum period of one hour. If the context is a two hour fast ramp, then the storage must fulfill that time constraint.

[22] However, the total losses with storage are not simply the efficiency 7%; they are 7% of the net charging and discharging power, integrated without respect to sign over the hour. Thus, if the device is cycled 10 times in the hour, the losses could be 7% times 10 times the charge / discharge time which is necessarily no greater than 1/10 of an hour. Thus, the losses are at most 7% but could be much less. Under severe ramping conditions the device would be in a constant state of charge or discharge through the hour, and the losses are simply the 7%.

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Assuming 10 percent storage losses as an example, the 100 MW storage device will experience 10 MWh of losses compared to the CT energy production of 50 MWh. Looked at one way, this is a net 60 MWh difference in delivered energy as the storage device must be supplied energy from other resources. Depending upon what resources are on-line and at the margin, this could be a CT, a combined cycle gas turbine (CCGT), a nuclear plant, or a hydro plant – or conceivably renewable resources during the storage charging cycle. In an extreme case, if the renewable resource would have to be curtailed without the storage, then there is no net loss.

A second perspective on the equivalency question is to ask what the relative benefits to system performance are of the CT and the storage device. This can be defined in terms of the maximum ACE or the maximum frequency deviation, or the impact on CPS1 or other criteria. The context of the benefits then becomes an issue – what is the total level of regulation relative to the required level for a given degree of renewables penetration and for a given base level of regulation provided by storage versus CTs? Is the storage unit the first 100 MW of storage when the system has insufficient regulation, or is it displacing 100 MW of CT provided regulation? A similar question can be asked with regard to 100 MW of incremental regulation from a CT. In the latter case an additional question arises, the 100 MW of incremental regulation spread across all conventional units on regulation, all CTs on regulation, or just one CT and what the size and ramping capability of that CT?

In terms of providing ramping capability, it is also possible to perform some straightforward analysis. Power electronics based storage with advanced electro-chemistries is virtually instantaneous for regulation purposes. This is faster than regulation needs, so the benefit of the storage is to provide the minimum ramping rate required. If the CT can provide that ramp rate then the two technologies are equivalent. If the CT is capable of providing only half the ramp rate, then the equivalent storage is only half the CT, assuming adequate storage duration.

During *quiet* periods of renewable production when all that is required is to manage renewable volatility, the performance requirements for storage and conventional units may be modest. Then, the differences between the two technologies are also modest. During periods of high renewable ramping, the dynamic performance differences will be more important.

Finally, the storage device will not incur charging and discharging losses while it is *waiting* for a severe ramp. Stated differently, if in *quiet* periods the storage device only experiences charge-discharge cycles of 5 to 10 percent of its capacity, then the losses are correspondingly less. However, the CT must consume fuel and provide energy if it is *on* waiting on the ramping because a start-up cycle is not acceptable. This energy consumption is not a loss, of course, but must be measured against the cost of the displaced energy at the margin from other units – CCGT, nuclear, or hydro.

Considering all the different perspectives on the question of identifying the storage equivalent of a 100 MW CT, the approach decided on was as follows:

- Produce an analytical comparison of regulation up/down available and ramping available.

- Define and simulate scenarios where the regulation available is restricted to a representative set of hydroelectric and CT units and matches the maximum regulation utilized by the AGC. Increment the AGC available and the regulation used by an amount equal to half of the capacity of a 100 MW CT, using the closest and highest performance unit in the fleet.
- Compare this to the benefit of adding 100 MW of storage and 50 MW of storage instead of a CT.
- Also compare this to incrementally adding a CT to cases where storage and CTs share the regulation. Add storage similarly.

These cases should provide a comparison of the relative effectiveness of the two technologies.

It would also be possible to compare the effectiveness of adding the 100 MW CT unit with the assumption that it is scheduled *on* at full power awaiting a renewable ramp down and similarly scheduled *on* at minimum power awaiting a renewable ramp up. These results can be extrapolated from the results obtained by the comparisons above.

2.12. Task 12. Identify Policy and Other Issues to Incorporating Large-Scale Storage in California

Based on the insights gained from the analysis, the researchers worked with the California ISO to develop a list of issues and policies regarding the impact of increased renewables on the system and integration of storage. The purpose of this task was to provide guidance for future policy decisions and future research and analysis efforts.

The policy questions revolve around the market products and protocols available today versus those that might encourage the use of storage. Also considered was the possibility of new interconnection requirements or protocols for renewable resources, plus the tax incentives available to renewable developers and how these relate to storage.

The United States Congress is considering legislation to establish tax incentives for large-scale electricity storage and the issues around how these might impact storage development in California will be discussed as well.

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3.0 Project Outcomes

Over 500 simulations were performed across a wide variety of system conditions, future renewable scenarios, regulation levels, and storage configurations. The table below (identical to the one in Section 3.0 with a *findings* column added) summarizes the steps in the project, the types of simulations run, and the findings in each case. Because of the very high number of potential combinations of parameters, only those steps that lead to quantitative results for particular years were performed for all future renewables scenarios; steps such as determining control algorithms and tunings were only performed using representative days.

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Table 4. Outcomes summary

Year / Renewable Scenario	Current	20% RPS	33% RPS Low Estimate	33% RPS High Estimate	Comments	Findings
Project Study Element						
Calibration	All days plus one June day*	N/A	N/A	N/A	June used a unit trip to calibrate frequency response of system	Model Calibrated
Determining Impact of Renewables under Current AGC	All days	All days	All days	All days	February, April, July, October	Maximum ACE > 3000 MW in 2020
Determining Levels of Regulation Required to Accommodate Renewables	N/A	All days	All days	All days	Cases studies with AGC values of 400 - 3,200 MW all cases, and 4,000/4,800 MW where required	3200 - 4800 MW Required variously
Determining Levels of Regulation Required to Accommodate Renewables	N/A	None	None	July Day	Cases with 2,400 - 4,000 MW of regulation were modified to keep all CT's on providing regulation	Some improvement via altered scheduling
Determining Levels of Regulation Required to Accommodate Renewables	N/A	None	None	All days	Cases were run with 800-3,200 MW of regulation was allocated to a CT and Hydro subset, matching 3,200 MW regulation level	Results varied numerically but were qualitatively consistent
Determining Levels of Storage Required to Accommodate Renewables (Infinite Storage Approach)	N/A	All days	All days	All days	Cases studied with storage levels of 10,000 MW and 12 hr duration	3,000 MW of storage was "sweet spot" except in April
Validating Storage Levels and Determining Durations	N/A	All days	All days	All days	3,000 MW and 4,000 MW cases validated across duration ranges 1 - 4 hrs	Validated 3,000 MW and 2 hours (4,000 MW in April)
Developing and Validating Storage Control Algorithm	N/A	None	None	July Day	Many cases run with various schemes and then with all combinations of PID tunings. Selected controls/tuning were used in subsequent cases	PID with anti-windup used for AGC for conventional units and (separately) for storage
Determining Storage Rate Limit Requirements	N/A	None	None	July Day	Cases run with storage rate limits varying from 2.5 to 100 MW/second. Resulting 10 MW/sec were used in all subsequent cases	Rate limit > 5 MW/sec required
Examining Trade-offs of Storage and Regulation	N/A	None	None	All days	Cases with varying combinations of regulation and storage totaling as much as 5,000 MW	Regulation never as effective as storage

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Year / Renewable Scenario	Current	20% RPS	33% RPS Low Estimate	33% RPS High Estimate	Comments	Findings
Examining Trade-offs of Storage and Regulation Against Real Time Dispatch Periodicity	N/A	None	None	July Day	Cases with varying combinations of regulation and storage re-run with RTD @ 30 seconds	30 sec RTD only marginally better if that
Examining Trade-offs of Storage and Regulation	N/A	None	None	July Day	Sensitivity analyses of incremental 100 MW regulation or 100 MW storage across range of regulation/storage combinations	Storage slightly better - regulation dispersed cross many plants
Examining Trade-offs of Storage and Regulation	N/A	None	None	July Day	Trade-offs were re-examined with the regulation allocation used above for a subset of CT and hydro units	Similar outcomes
Droop Investigations	N/A	None	None	July Day	Droop was doubled on all conventional generators and results studied	Doubling droop not beneficial
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3,200 using the Regulation Allocation to only a subset of CT and Hydro units	Established consistent base cases for incremental analysis
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3,200 MW with a 110 MW CT added	30 to 50 MW of Storage Equivalent to 110 MW CT - varies with amount of regulation available
Analyzing Storage Equivalent of 100 MW CT - base cases	N/A	None	None	All days	Analyzed for a range of AGC Regulation MW used from 800 to 3200 MW with 50 and 100 MW storage added	
Emissions Impacts	N/A	July Day	July Day	July Day	Emissions from CT and CCGT were calculated across various regulation and storage cases	Use of storage can save 3% of emissions

***All days refers to the four total sample days. One day in each month of February, April, July and October.**

Source: model summary

3.1. Simulation Calibration

As described in Section 2.2, to obtain validity in model predictions, the model was calibrated using actual 2008 and 2009 data. The researchers successfully calibrated the power grid dynamics according to historical data. Researchers compared model output to historical data on ACE, frequency deviation, the power spectral density of ACE, the amount of balancing energy required in the real time dispatch, the marginal clearing price in the real time dispatch, and typical unit movement during the day. Graphs of time series data on frequency deviation and ACE from July are used to illustrate results. The appendix provides additional graphs for the remaining days.

3.1.1. Power Grid Dynamics

Figure 16 compares the model output with historical data on system frequency deviation for the July base day. The graph on the left illustrates actual frequency deviation and that on the right illustrates modeled frequency deviation. Both the amplitude and shape of the model's estimated frequency deviation match historical values.

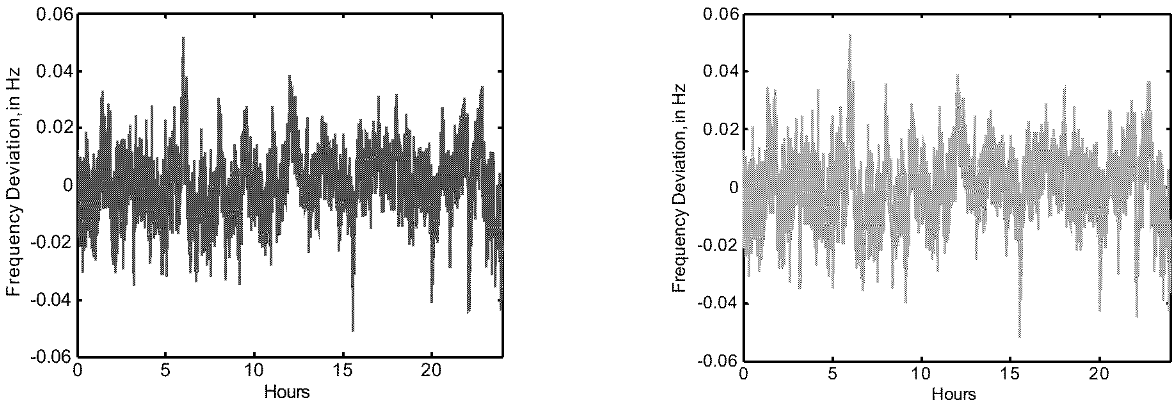

Figure 16. Historical frequency deviation (left) compared to step 1 calibrated model frequency deviation (right)

Source: California ISO data and model output, respectively

Figure 17 compares historical ACE data for the same date with modeled ACE output. Again, the graph on the left represents the historical data while that on the right represents model output. Both the amplitude and graph shape match between the two, indicating successful calibration of grid dynamics.

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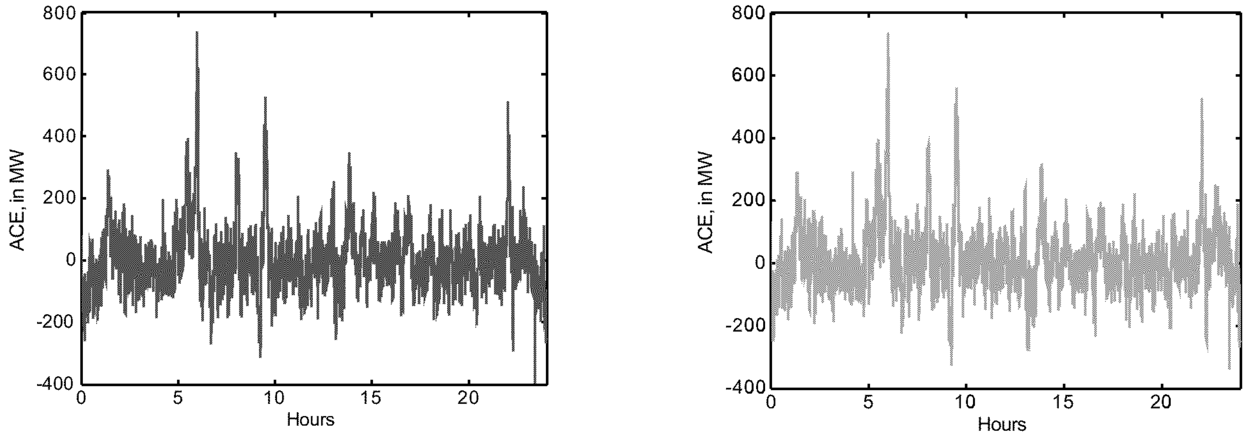

Figure 17. Historical ACE (left) compared to step 1 calibrated model ACE (right)

Source: California ISO data and model output, respectively

3.1.2. Primary and Secondary Controls

The researches applied a similar tuning approach to calibrate the performance of the primary and secondary generation controls, including AGC signals. Figure 18 and Figure 19 illustrate the results of this effort for the July sample day. While the amplitudes do not match precisely, the shapes of the curves match closely.

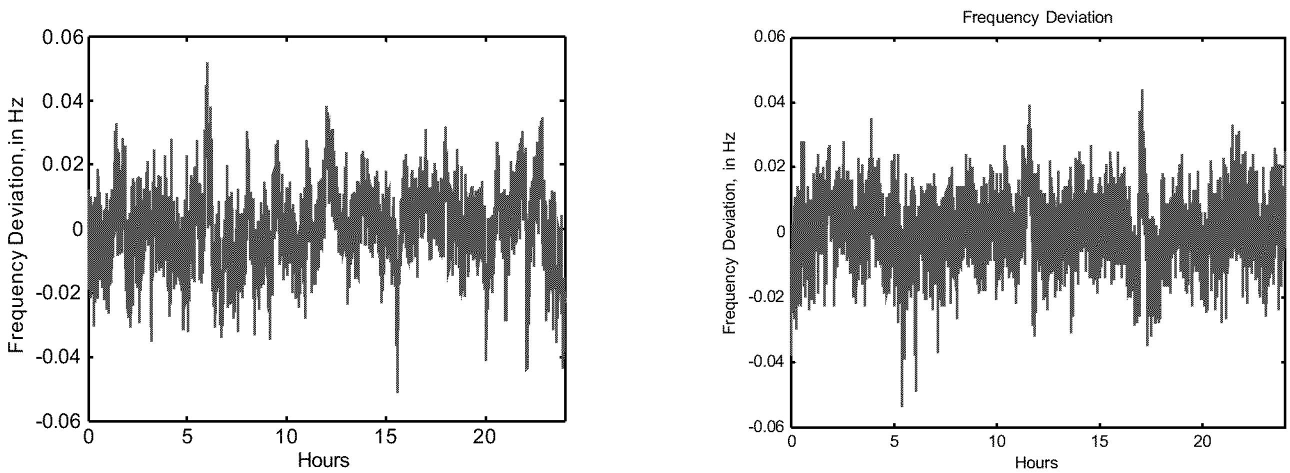

Figure 18. Historical frequency deviation (left) compared to step 2 calibrated model frequency deviation (right)

Source: California ISO data and model output, respectively

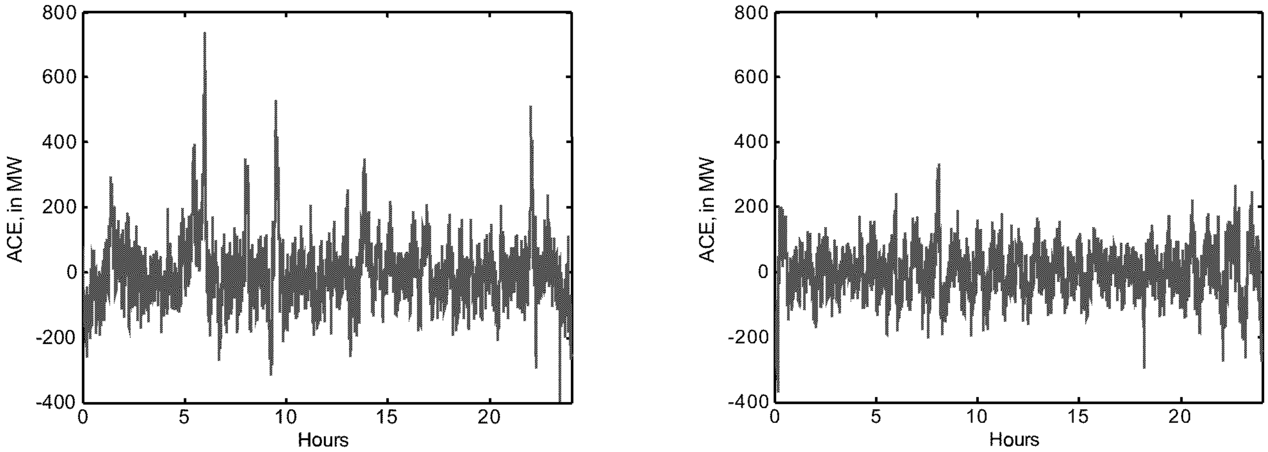

Figure 19. Historical ACE data (left) compared to step 2 calibrated model ACE output (right)
Source: California ISO data and model output, respectively

The calibrated simulations are arguably using 4-second load data that is back-calibrated from observations of system frequency and generation as explained above. However, it was deemed infeasible to calibrate the simulated AGC to actual AGC signals sent to generating units. The simulation is *optimistic* in that all units are able to participate in regulation and that when a unit is *instructed* by AGC or real-time dispatch, it responds correctly. Unit delays in response beyond ramp rate limits and unit deviations from schedule are not incorporated in these simulations. Thus, the ATC performance in future renewable scenarios is a *best case* representation of the system ability to accommodate renewables assuming that all conventional units respond correctly and promptly.

3.2. Droop and Ancillary Needs With Current Controls

3.2.1. Introduction

Results from the analysis of additional renewables, assuming current droop settings and regulation amounts (e.g., 400 MW AGC bandwidth) and without any storage facility additions, indicate severe degradation of system performance in 2012 and unmanageable performance in 2020. Without storage, additional regulation resources beyond the current 400 MW of regulation will be necessary.

For all study days, researchers observed increasing degradation of ACE as the share of renewables increased in the generation portfolio. ACE performance was severely degraded in all of the 2012 and 2020 cases, with maximum ACE levels more than doubling and tripling the 2009 levels as shown in Figure 20. With an AGC bandwidth of 400 MW and no storage additions, the maximum observed ACE variation within one day was -600 MW to +1,100 MW for July 2012, and -1,900 MW to over +3,000 MW for July 2020 High. These results were obtained with all conventional units (CT, hydro, and CCGT) on regulation. The CCGT units are actually much slower than the others and are normally not in regulation. Another set of analyses were done with a *realistic* allocation of regulation to the CT and hydro units only, and only in amounts and to as many units as were required to fulfill the AGC regulation requirements. In general, these produced better results, even though total unit capacity set aside for regulation was reduced. While the results are improved quantitatively, they are not qualitatively different. This is show in Figure 20.

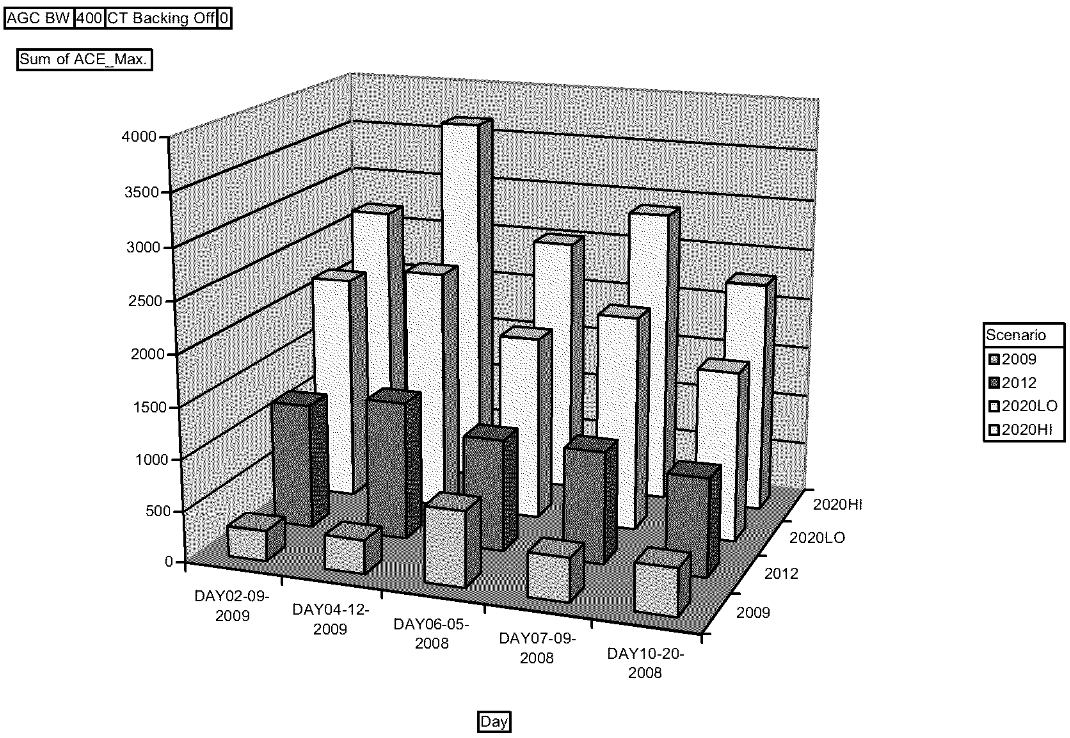

Figure 20. ACE maximum across all scenarios
Source: model output

As illustrated in Figure 21, frequency deviation is fairly unchanged across scenarios, varying up to around 0.06 Hz. This is because the bias of the WECC system is such that it takes a very large imbalance to generate a 0.1 Hz deviation.

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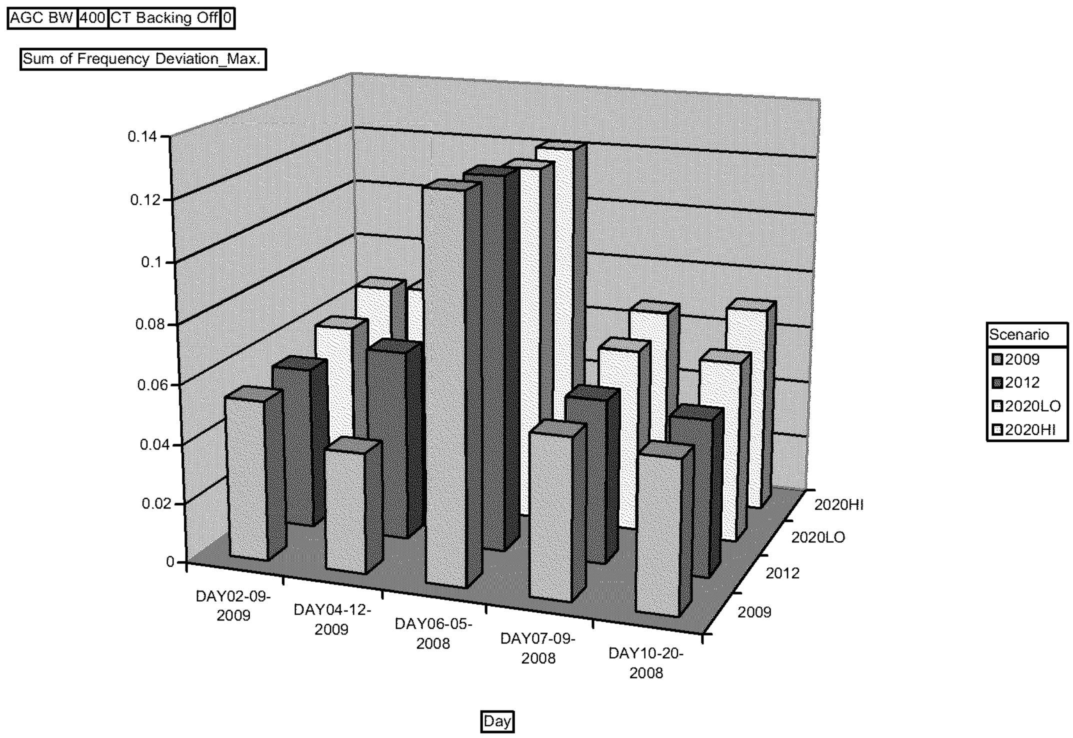

Figure 21. Maximum frequency deviation across all scenarios
Source: model output

While the levels of renewables ramping greatly increase the need for frequency regulation, generator droop does not appear to be a factor in frequency regulation or ramping performance in 2012 or 2020.

The following subsections provide detail on ACE, droop, and balancing energy results, using the July day as an example. Additional results for each of the modeled days are available in the appendix.

3.2.2. Area Control Error

Generally, across all days, large ACE deviations occurred twice a day, once in the morning and once in the evening. Degradation in system performance appears to be predominantly caused by renewables ramping in the morning and evening. Renewable variability in the high renewable cases exacerbates the ACE degradation further. Figure 22 illustrates ACE degradation for a July 2012 and 2020 scenarios, alongside the total hourly renewable production for that day to illustrate. The source of the high ACE was determined not to be the actual rate of change of the renewables as much as issues associated with the interaction of renewable forecasting and scheduling with the scheduling of conventional generation, and how AGC interacts with these. A detailed exposition of this is contained in slide form in the appendix.

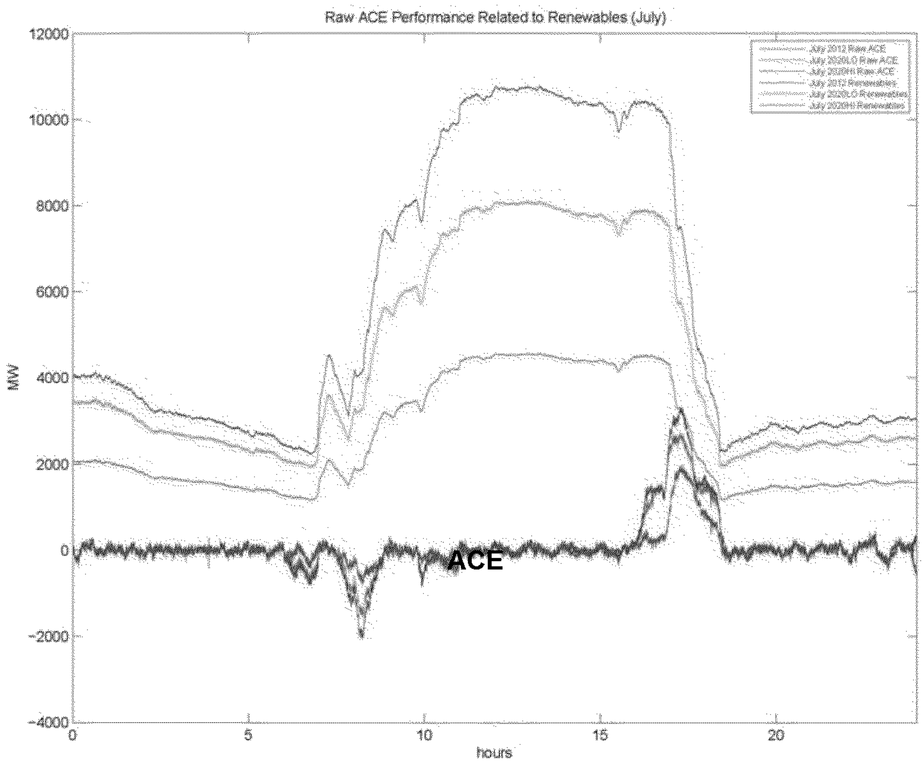

Figure 22. ACE results for July day scenarios
Source: model output

The predominant cause of ACE degradation in future years is the ramping of wind down and solar up in the mornings, and vice versa in the evenings. Variability of renewable production in the high renewables cases of 2020 cause additional ACE movement.

Wind production decreases in the morning roughly an hour before solar production increases, depending on the day of the year. As such, there is a large drop in wind production in the morning, followed by a rapid pick up of solar an hour later. This occurs just as load is ramping up. The reverse occurs at the end of the day. Commitment of the combustion turbines and combined-cycle turbines as needed to accommodate the renewable generation greatly restricts the ramping ability of the remaining conventional generation.

3.2.3. Droop

Droop does not appear to be a factor in frequency regulation or ramping performance in 2012 or 2020. In particular, doubling the droop settings of the units produces negligible change in system performance. This is illustrated by Figure 23, which depicts system ACE with different amounts of droop, and Figure 24, which depicts system frequency deviation with different amounts of droop.

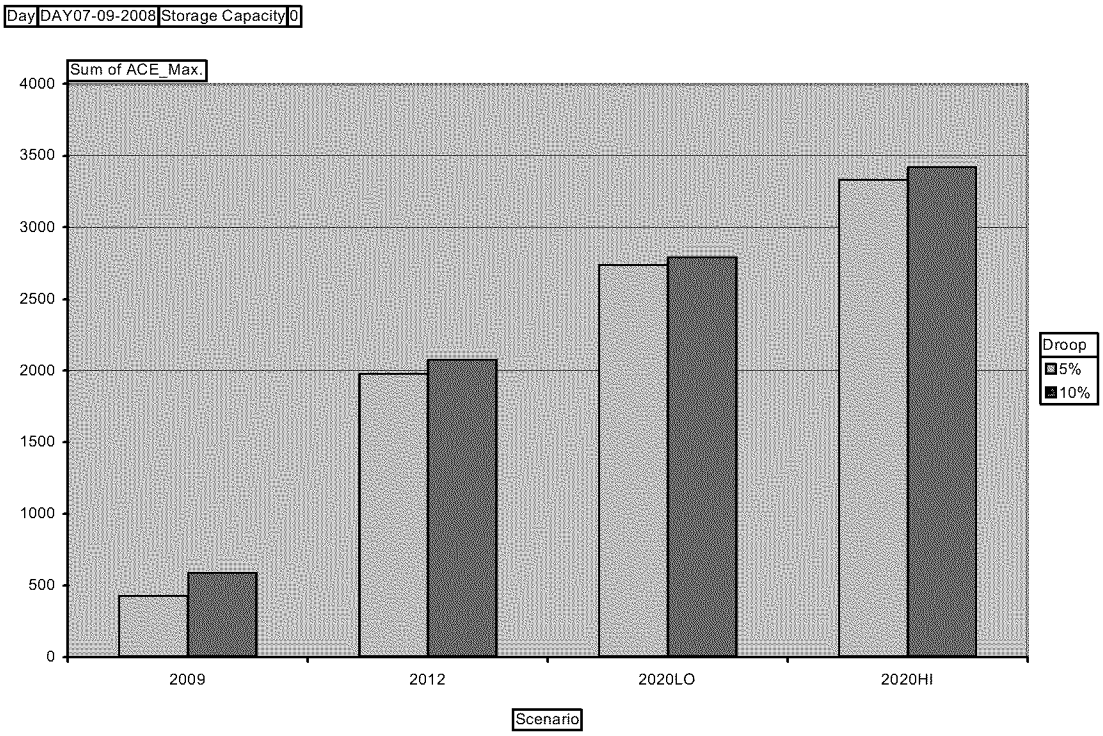

Figure 23. ACE across all scenarios with droop adjustments only
Source: model output

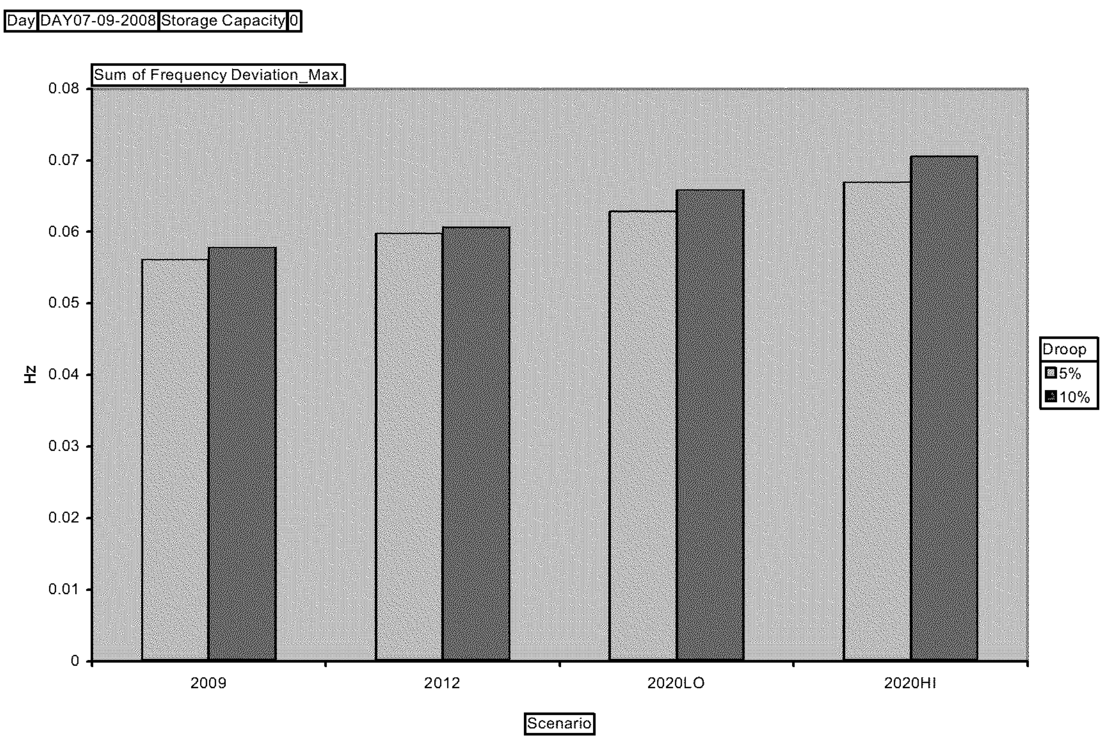

Figure 24. July 2009 frequency deviation across all scenarios with droop adjustments only
Source: model output

Droop adjustments have little impact on system performance because the ramp rates required to make up for sudden changes in renewable production are beyond what conventional generation can provide. Note that this does not mean that droop should be revisited for conditions where the amount of conventional generation on line is greatly reduced and insufficient system droop is available for a large unit trip. However, the conventional unit droop is sufficient today for evening conditions and light load in the event of a nuclear plant trip and can be reasonably expected to be so in the future.

3.3. Assessment of Storage and AGC

3.3.1. Introduction

The amount of regulation required for AGC to maintain ACE within today's limits was 800 MW in 2012, roughly double today's amount, and 3,200 to 4,800 MW in the 2020 High renewables scenarios, roughly 8 to 12 times today's amount. Infinite storage at first failed to adequately control ACE as expected, using the output of the conventional AGC system. When large-scale storage was configured as a resource similar to conventional generation, providing regulation services results were suboptimal. Using a fast and very large storage system resulted in excellent ACE performance in all scenarios once the storage control algorithms were developed, as described in the following section.

3.3.2. Increased Regulation

The ability of AGC to control renewables volatility and ramping using today's controls and protocols was evaluated. Researchers found that the amount of regulation required for AGC to maintain ACE within today's limits was 3,200 to 4,800 MW in the 2020 High renewables scenario. This was not because of momentary volatility; lesser increases are needed for that. Rather, such amounts were required to address diurnal ramping, especially that of the centralizing thermal solar production. Figure 25 depicts ACE maximums across all July scenarios, and Figure 26 depicts time series data of ACE in the July 2020 High scenario, with different amounts of regulation. Across the scenarios, increased regulation helps return ACE to 2009 values. However, performance remains marginal even at these levels of regulation. Figure 25 below is again with all conventional units on generation. Figure 25 shows the results when a realistic assignment of regulation to units is made.

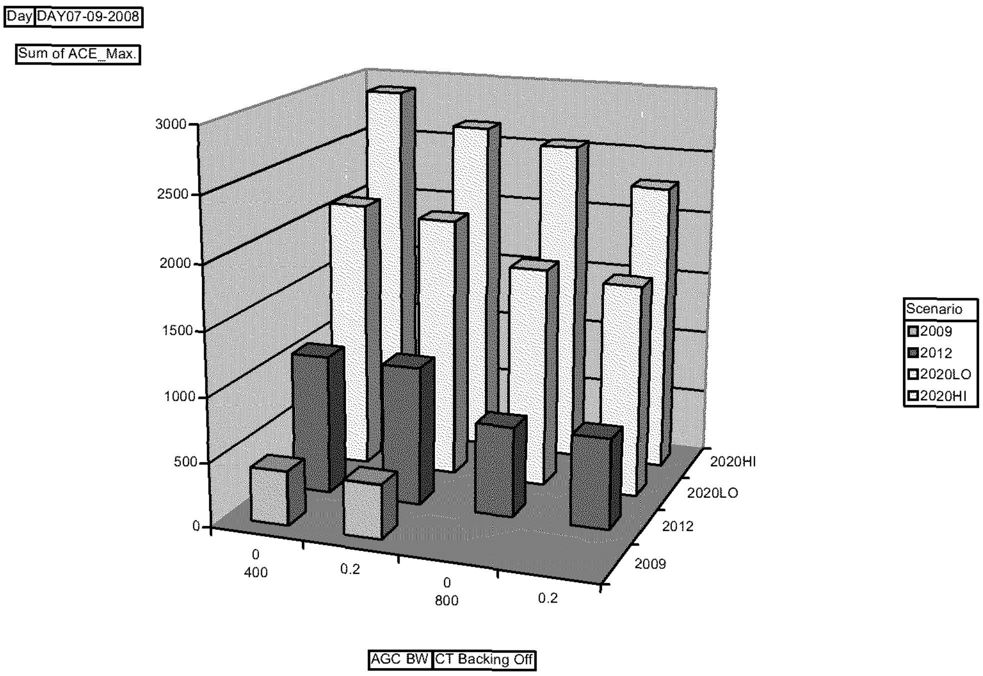

Figure 25. ACE maximums for July day across scenarios with increasing regulation and no storage
Source: model output

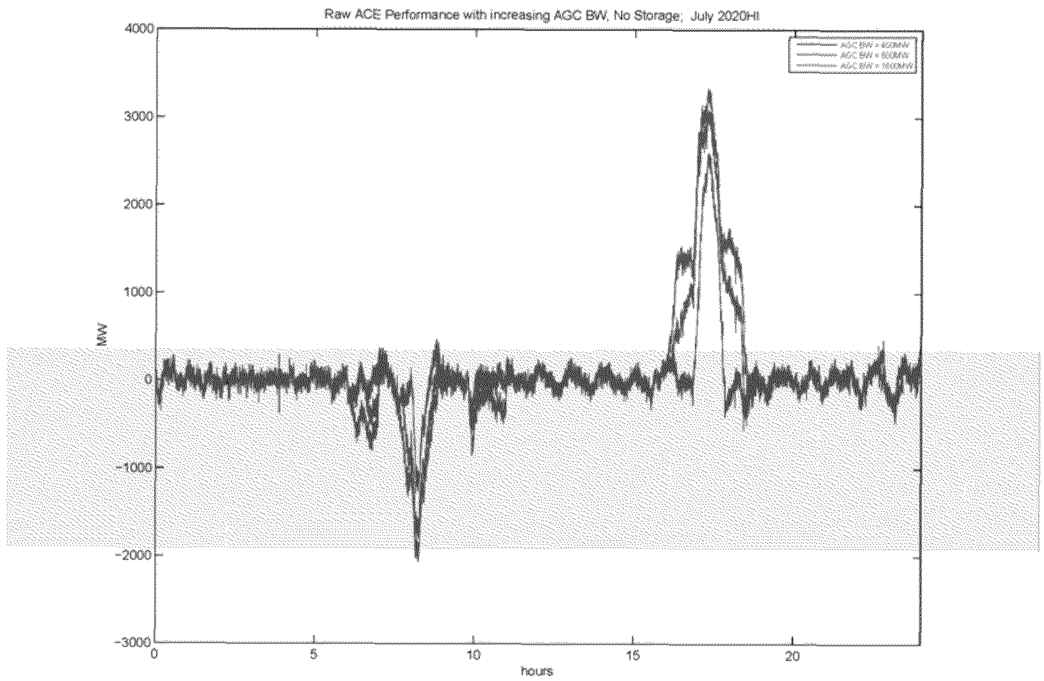

Figure 26. ACE performance for July 2020 High scenario with increasing regulation and no storage
Source: model output

Analysis of the 2020 High scenario for the July day show that 3,200 MW of regulation is needed to accommodate the renewable evening ramping. Still more is required to maintain ACE at nominal levels. Researchers found that April 2020 would require in excess of 4, 000 MW of regulation. Even then, the performance is marginal.

Figure 27 illustrates the frequency deviation for the July 2020 High scenario with different amounts of regulation. As expected, the change in frequency deviation across scenarios is fairly minor.

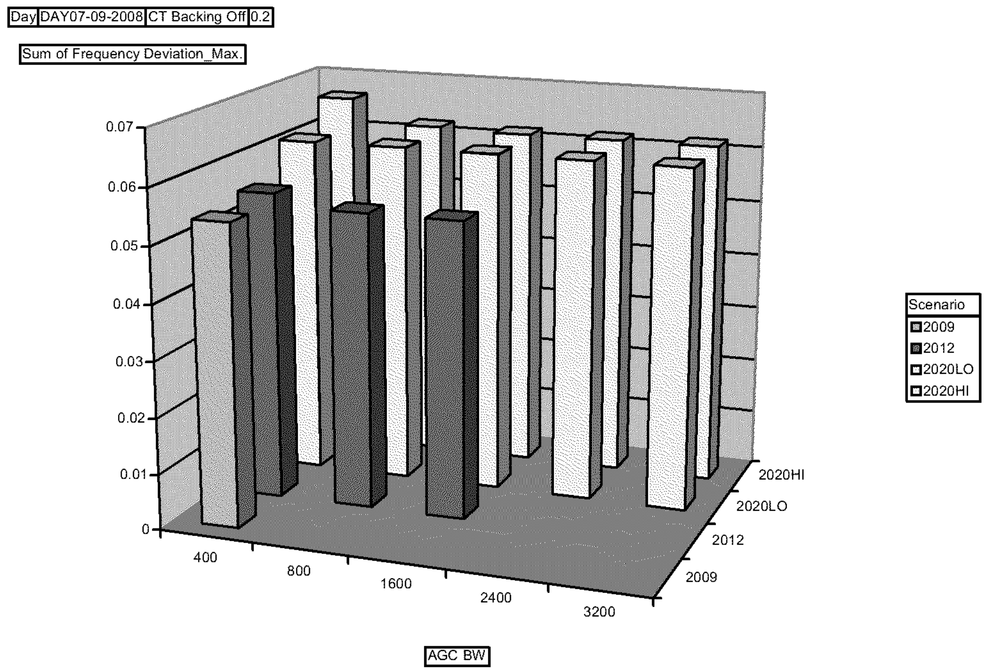

Figure 27. Frequency deviation maximum with increasing regulation and no storage, for July 2020 High scenario

Source: model output

The researchers and the California ISO observed that procuring this much regulation from conventional units when renewable production was quite high posed problems in and of itself. Renewable production in these scenarios peaks at 10,000 MW or more, well in excess of 20 percent of generation required. If the conventional units are scheduled strictly on an economic basis, the CTs will be the first units to be displaced by the renewables. Hydroelectric and nuclear generation will generally be the last to be displaced. CTs normally provide a significant amount of the regulation capacity in the system. CCT units generally have much lower maximum ramp rates and cannot provide the same regulation service as combustion turbines. As noted above, the generation schedules were constrained to maintain combustion turbines *on* during the day and available for regulation service so that these very high levels of regulation could be realistically provided.

Aside from the ramping phenomena, the renewables cause increased volatility during *normal* operation. This was observed to result in increased ACE and degraded performance, but nearly to the same degree as the ramping phenomena. Accordingly, it was investigated how much

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additional regulation would be required to maintain system performance during the hours 10 AM to 6 PM – i.e., between ramps. The results of this are shown in Table 5. It can be seen that if ACE maximum should be maintained below 500 MW and CPS1 above 180, for example, increased regulation will be needed in 2012 and 2020. As a general observation, it seems that in 2012 800 MW or more is required and in 2020 as much as 1,600 MW.

Table 5. System impact of additional regulation amounts

Scenario	Regulation	Worst max ACE	Worst frequency deviation	Worst CPS1
2012	400	477	0.0470	184
	800	325	0.0425	195
	1,600	316	0.0424	196
2020 Low	400	690	0.063	173
	800	480	0.061	190
	1,600	480	0.061	194
	2,400	480	0.061	194
2020 High	400	950	0.062	141
	800	662	0.061	172
	1,600	480	0.061	191
	2,400	382	0.061	191
	3,200	382	0.061	191

Source: model outputs

Figure 28 illustrates how CPS1 varies across scenarios for each day analyzed.

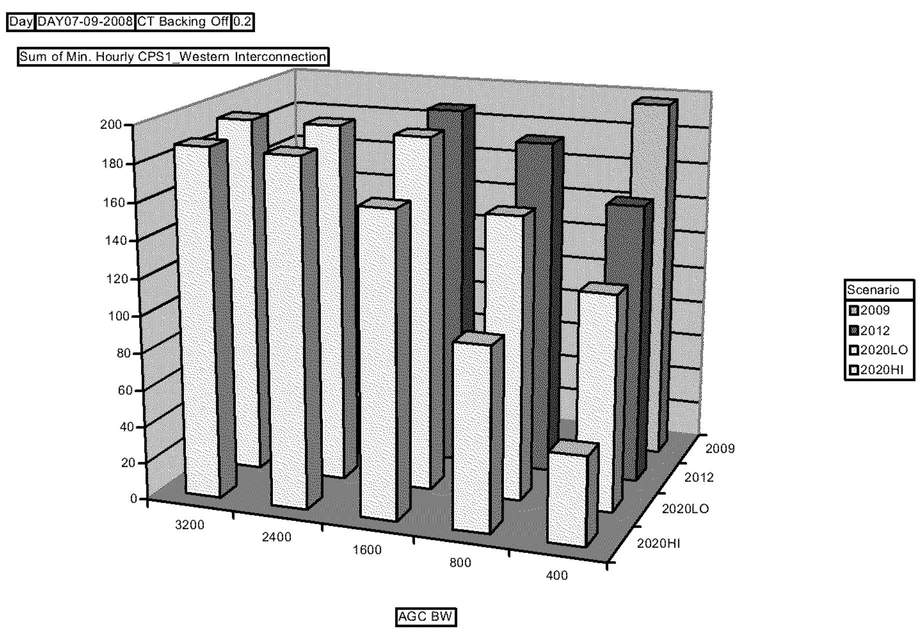

Figure 28. CPS1 minimum with increasing regulation and no storage, for July 2020 High scenario

Source: model output

3.3.3. *Infinite Storage*

When large-scale storage was configured as a resource similar to conventional generation providing regulation services results were suboptimal. The conventional AGC had primarily proportional control with limited integral gains in the control algorithm. This is because in the California ISO area, the AGC is not the primary mechanism for following ramping; the real time dispatch is. As a result, the AGC typically has to deal with relatively small fluctuations (at 400 MW of regulation procured, the California ISO AGC regulation bandwidth is 1 to 2 percent of system load or less). A ramp of 20 to 25 percent greatly exceeds AGC ability to respond. The proportional control algorithm will mathematically allow a constant offset of the error signal. In fact, with the necessary AGC gain of unity, the offset is about half the error before the large storage resource is employed. In other words, using storage as a conventional AGC resource provides only a 50 percent improvement in performance. This was seen consistently across scenarios and seasons. Figure 29 illustrates the ACE improvement provided by storage, for the July 2020 High scenario.

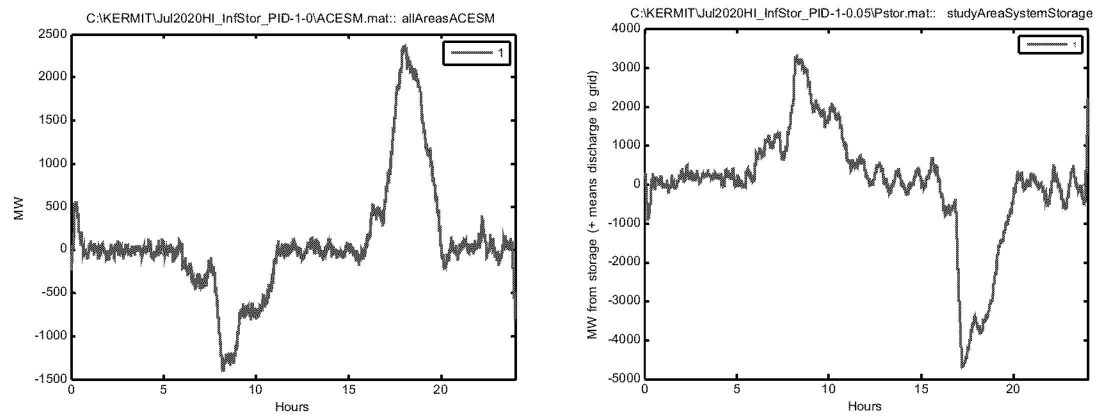

Figure 29. ACE results with storage and existing controls (left) compared to storage output, for July 2020 High Scenario

Source: model output

A Type-1 controller is required instead of a type-0 controller. However, the very different response characteristics of storage versus conventional generation militate against sharing the same control algorithm in a Type-1 mode. The conventional generators overall are slower than the storage and would not be stable with as aggressive an integral gain as the storage system will be. Also, the amounts of storage employed versus conventional generation will be different.

Thus, a separate PID control algorithm controlling storage as a resource separate from the conventional generators was developed and tested. This was found to successfully control ACE within tight bounds when sufficient storage was deployed.

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3.4. AGC Algorithm for Storage

The dramatic impact of the PID control algorithm on ACE performance for different RPS scenarios, compared to the baseline without storage, is shown by Figure 30. ACE variation falls within a tight band while storage *absorbs* the volatility.

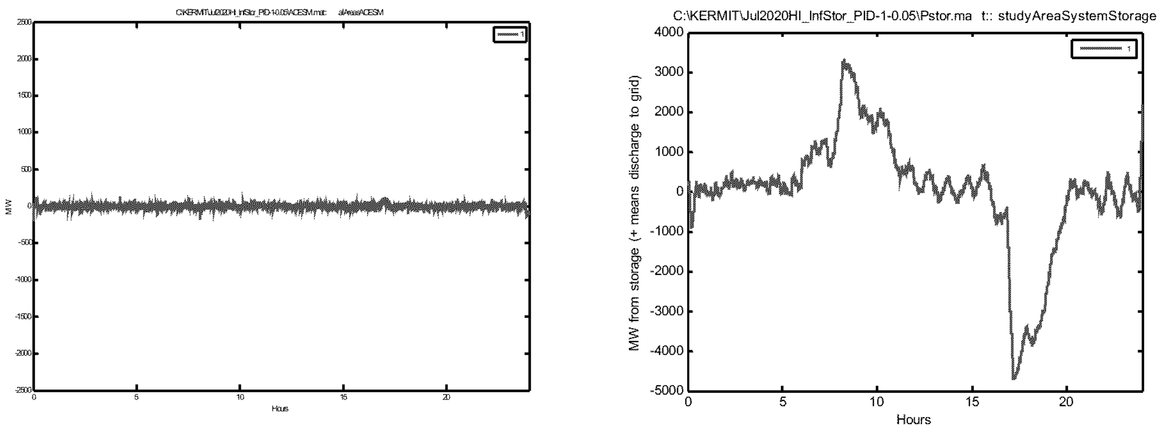

Figure 30. ACE performance with infinite storage (left) compared to storage output (right)
Source: model output

Furthermore, as shown above, this control algorithm required less than 4,000 MW of fast-acting storage capacity. These results clearly demonstrated that the PID control algorithm, in parallel with conventional AGC response, was an effective strategy for mitigating frequency performance concerns in the 2012 and 2020 RPS scenarios. Figure 31 shows maximum ACE with and without storage with revised controls across all scenarios in July. Controlled storage has a significant impact on ACE and a lesser though positive impact on frequency deviation.

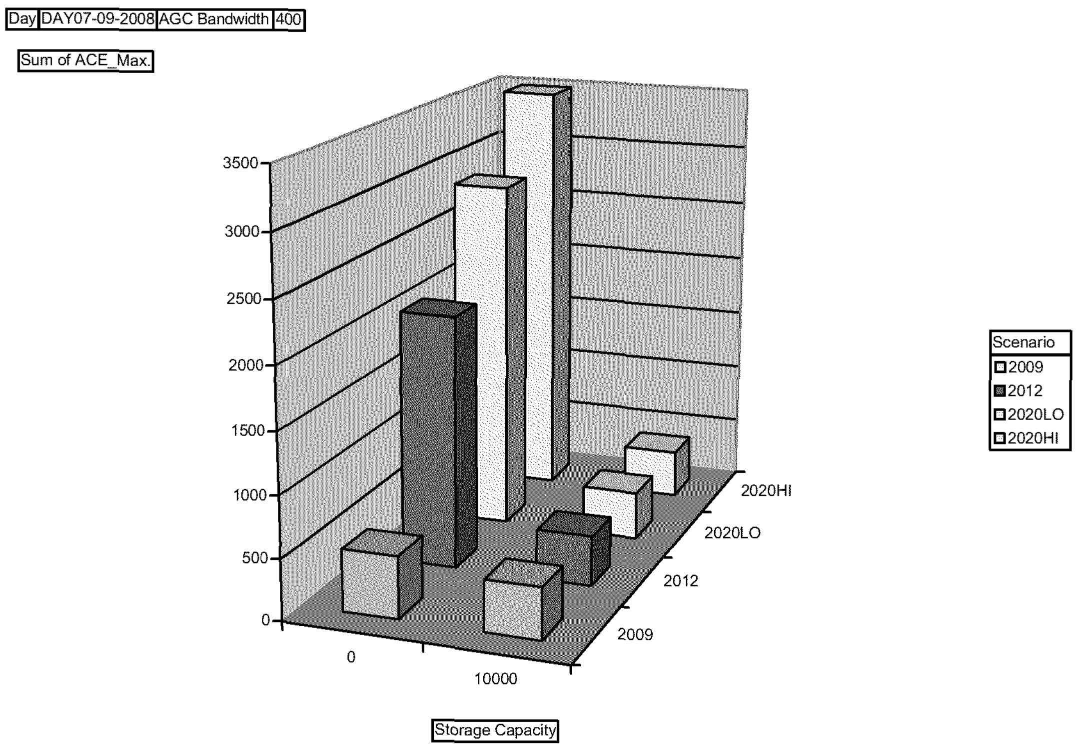

Figure 31. ACE maximums for July day, with No Storage and "Infinite" Storage
Source: model output

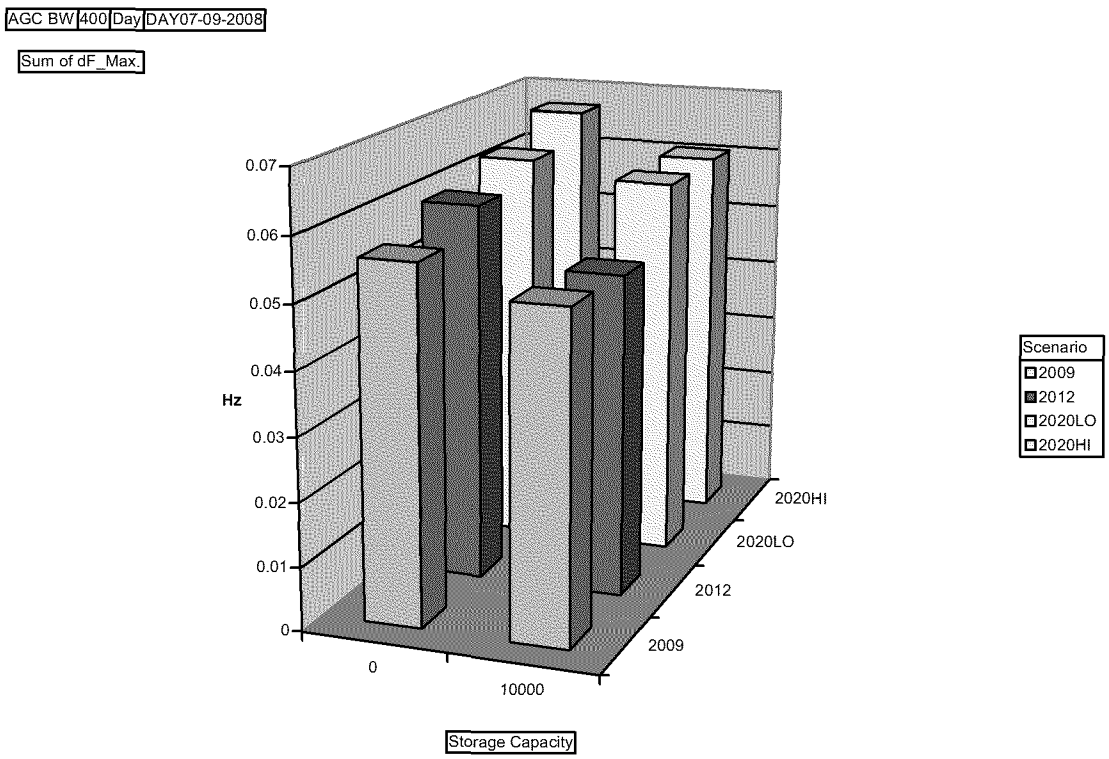

Figure 32. Maximum frequency deviation for July scenarios, with no storage and "infinite" storage
Source: model output

This work was then refined when PID tuning was examined as a function of the rate limit characteristics of the storage system. Exploration was made of altering the AGC algorithm to a similar PID controller. The existing California ISO AGC is believed to be primarily a proportional control system. The simulation includes provisions for PID control; an integral term is desirable to achieve more frequent zero crossings of ACE and reset system ACE to zero. Experiments determined that a derivative term was not necessary. It should be noted that when large amounts of grid-connected storage are available, the demands on conventional units for regulation are reduced, and the purpose of AGC for these units shifts to the real-time dispatch, which becomes the vehicle for tracking renewable ramping.

With both the storage control algorithm and the AGC control algorithm, the introduction of an integral gain term improves normal performance but can greatly degrade performance when the bandwidth of the control system is exceeded. In words, when ACE is greater than 1,000 MW, for instance, and the AGC bandwidth of available regulation is 400 MW, the AGC integral gain will continue to increase well beyond 400 MW, 1,000 MW, or any capacity limit until ACE is restored. This is a well-known phenomenon usually called windup – the correction for this is to impose an integral anti-windup limit on the output of the integral gain. This was implemented, tested, and determined to be effective. It is necessary for both the conventional unit AGC algorithm and the storage control algorithm.

When the storage or the conventional units dominate the regulation MW available, the two separate controllers can be configured as though each was independent of the other. This is valid for the cases assessing how much storage is required to self-regulate or conversely how much regulation is required absent storage. However, when both are present in significant amounts, there is a problem of coordination. Otherwise the system has the potential for over-control if both try to respond, which can degrade ACE performance below what it would otherwise be. This phenomenon was observed in first attempts to coordinate mixtures of storage and conventional regulation to assess the tradeoffs between them.

A first correction to the problem is simple – to allocate the control requirement to the two types of regulation based on the relative amounts each provides at maximum. This methodology solves the coordination problem but is suboptimal in that the faster response of the storage is not fully utilized. This issue was observed and addressed in earlier studies performed for AES and published by KEMA. However, the algorithm developed for that study as noted earlier is not suitable for the ramping phenomena that are a focus of this effort.

Consequently, a further refinement was made to the coordination of the two types of regulation. Conceptually, if the control requirement was a step function, the full step amplitude would be allocated to the storage (This is common with the earlier algorithm.), but the amplitude allocated to the storage is decayed with a simple time constant towards just the storage share. The time constant is chosen to approximate the response rate of the conventional fleet. (Thirty seconds in this case was used. Tuning of this was not further explored once it was satisfactory). The storage control algorithm is shown in Figure 33. A block diagram of the overall control algorithm developed is shown Figure 34.

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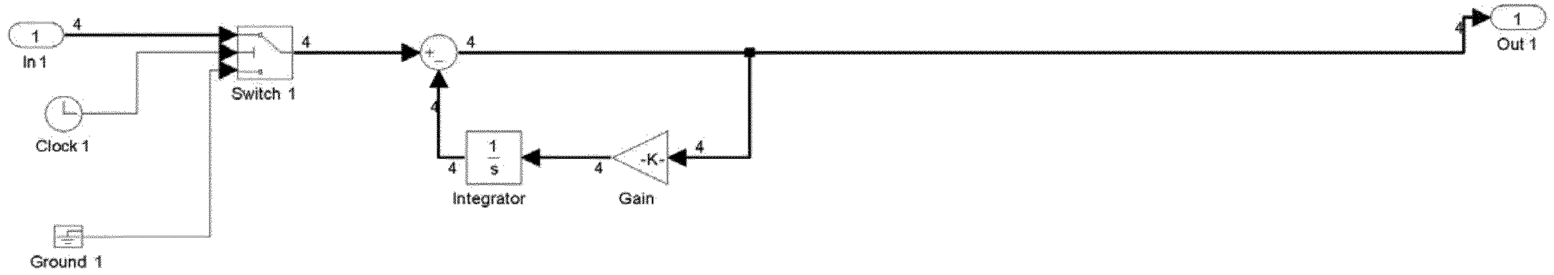

Figure 33. Storage control algorithm
Source: from KEMA model

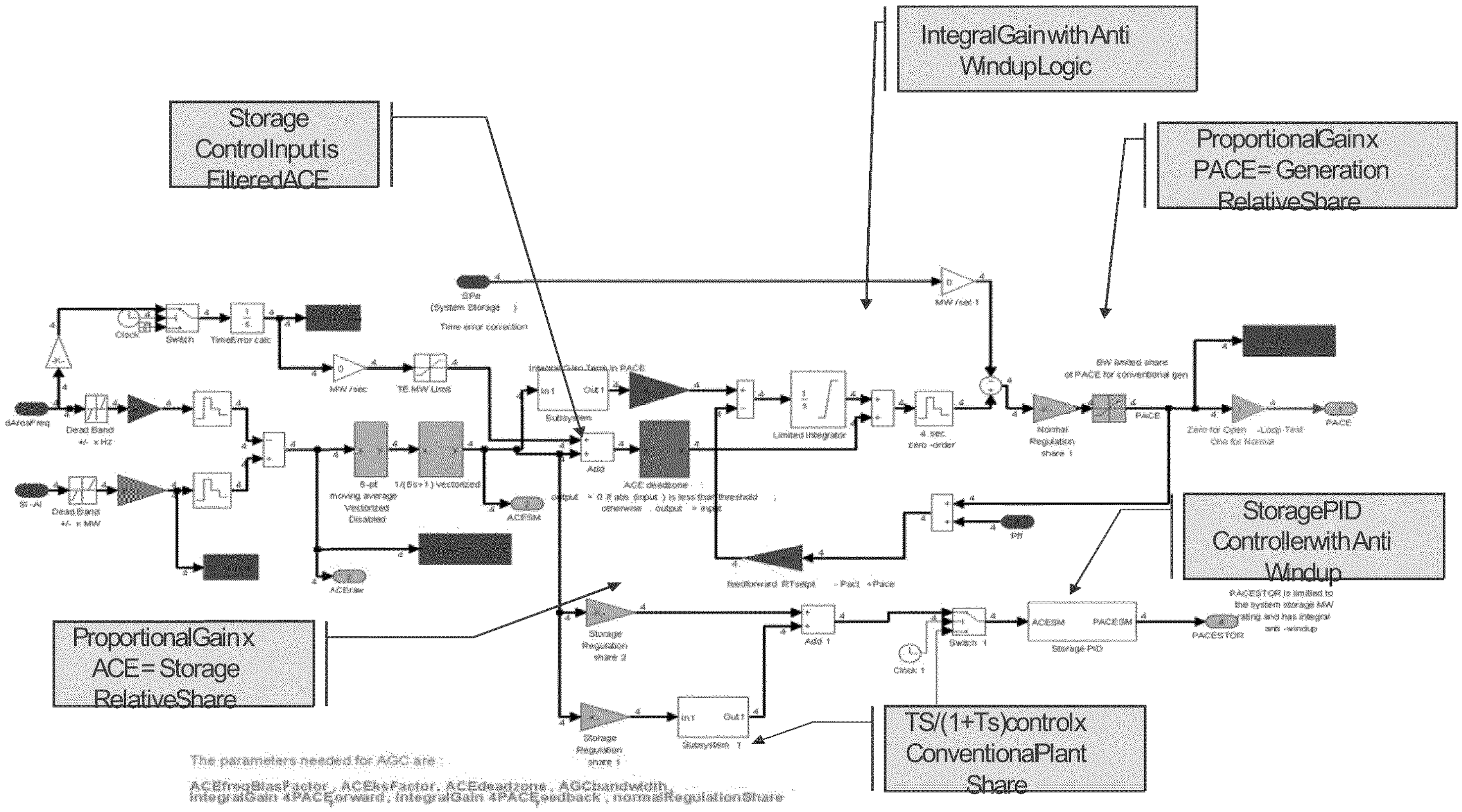

Figure 34. Block diagram of AGC

Source: visualization of KEMA model

It was determined that in cases when the storage is insufficient to restore ACE to zero promptly, an anti-windup feature was required. The output of the integral portion of the PID controller was limited to the total storage power available. This prevents the integral gain from *winding up* when the storage is depleted and ACE is not restored. The result of wind up is to have the storage fail to respond in the other direction (restore charge) when it should, and this results in net decreased performance. With an anti-windup installed, consistent good performance is obtained.

The storage systems used in the determination of storage size were modeled as having near-instantaneous response to desired changes in power output. While this is nominally true of modern power electronics, it is not known today if all storage media are capable of supporting these changes frequently at that rate. It is certain that some are not. For instance, CAES will have a rate limit equivalent to a gas turbine. Pumped hydro will have rate limits equivalent to hydroelectric facilities or possibly longer to change from pumping to generating.

The selected storage configurations were tested with rate limits varying from 1,000 MW/second to 2.5 MW/second in logarithmic steps. That is, 1,000, 100, 10, 5, and 2.5 MW/second were used. It was determined that the system performance was practically identical for the instantaneous, 1000, 100, and 10 MW/second limits but that performance degraded when the rate limit was 5 or 2.5 MW/second.

The rate limit of the storage system will alter the total system performance as a function of the PID controller tuning. In particular, slower responding storage will tend to *overshoot* more in response to a large ramp, as the storage may keep increasing power output after the need is past – this is typical of integral control at high gains with rate limited resources. The tuning of the PID controller versus rate limits was explored. The impact of storage rate limit on system performance, and the results of PID tuning versus rate limits are shown in Figure 35 and Figure 36.

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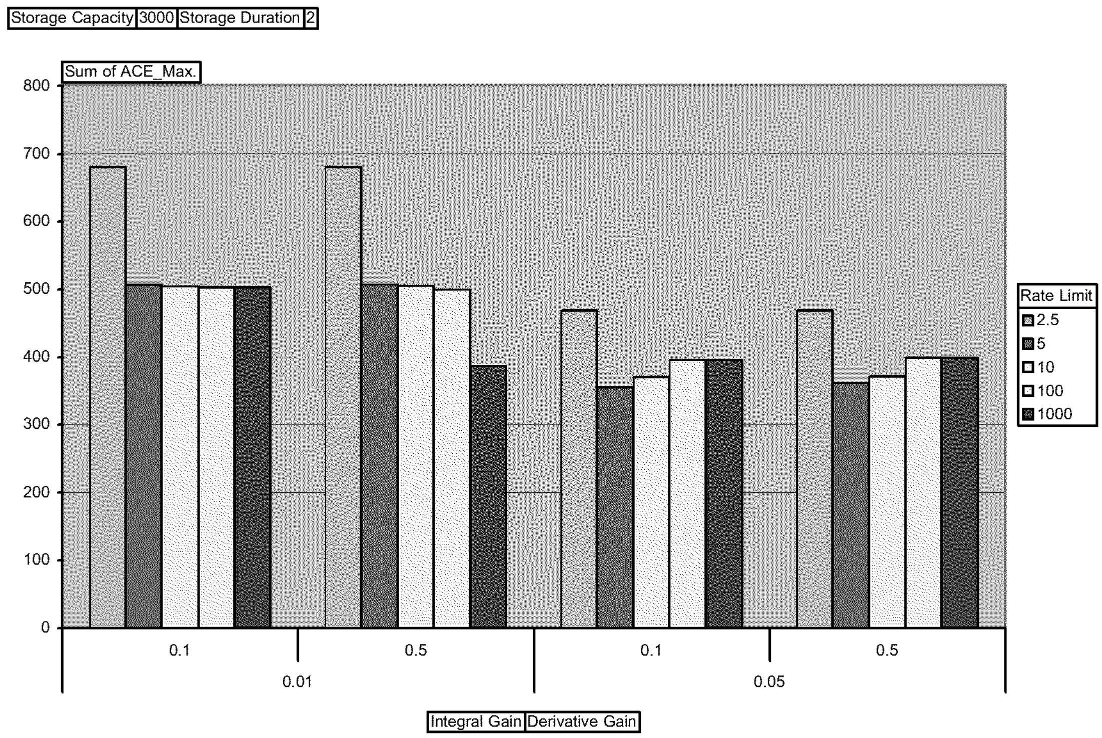

Figure 35. Maximum ACE by storage rate limit for 2020 High scenario, with storage of 3,000 MW and 2 hours and no regulation

Source: model output

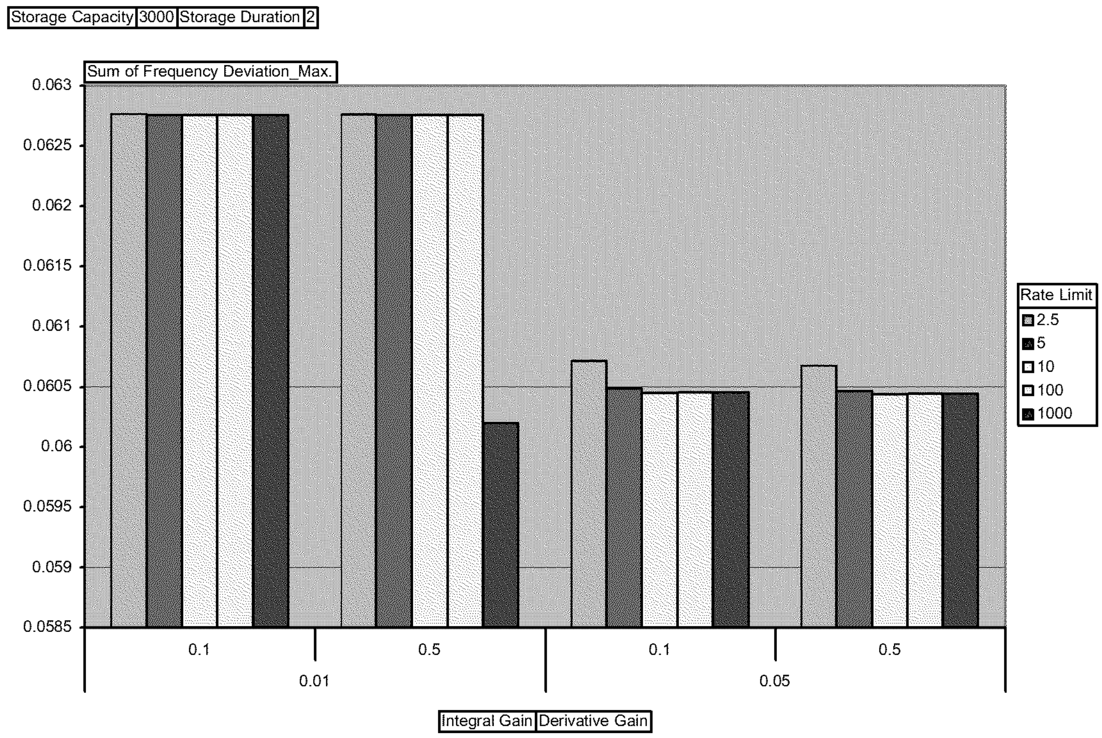

Figure 36. Maximum frequency deviation for July 2020 High scenario

Source: model output

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Analysis results should not be interpreted as definitive guidelines for controller tuning. What it does indicate is that the controller tuning has to be adapted to the storage on-line and its characteristics; it is probably desirable to plan on a scheme that adapts the tuning appropriately. For that matter, the development of a PID controller does not close the topic forever. A type 1 controller will have a steady state offset when following a ramp; it requires a type 2 controller to eliminate this offset. With the high performance storage simulated, the offset was not so great (from observed ACE) so as to require this, and project time/budget/scope did not allow further exploration. But a more sophisticated approach to controller design using root locus techniques may be able to shed further light on the subject. It may also be possible to develop a state-space model and optimal control design. However, as a general comment such an approach will encounter difficulty in obtaining necessary system parameters, and higher-order control designs on this basis are subject to poor performance when the parameters are incorrect. Simpler is better.

3.5. Relative Benefits of Different Amounts of Storage

Figure 37 and Figure 38 show the validation of storage capacities and durations for July. Similar data was produced and analyzed for all days and all renewables scenarios to validate the conclusion that 3,000 MW of fast-acting storage with a two-hour duration achieves solid California ISO frequency performance through the 2020 High RPS scenario, except the April 2020 High scenario which requires 4,000 MW of storage. This is an important finding because the two-hour discharge duration is within the range of current battery technologies. All days were studied but only the July 2020 High Renewables Scenario is shown in the report; other data is in the appendices.

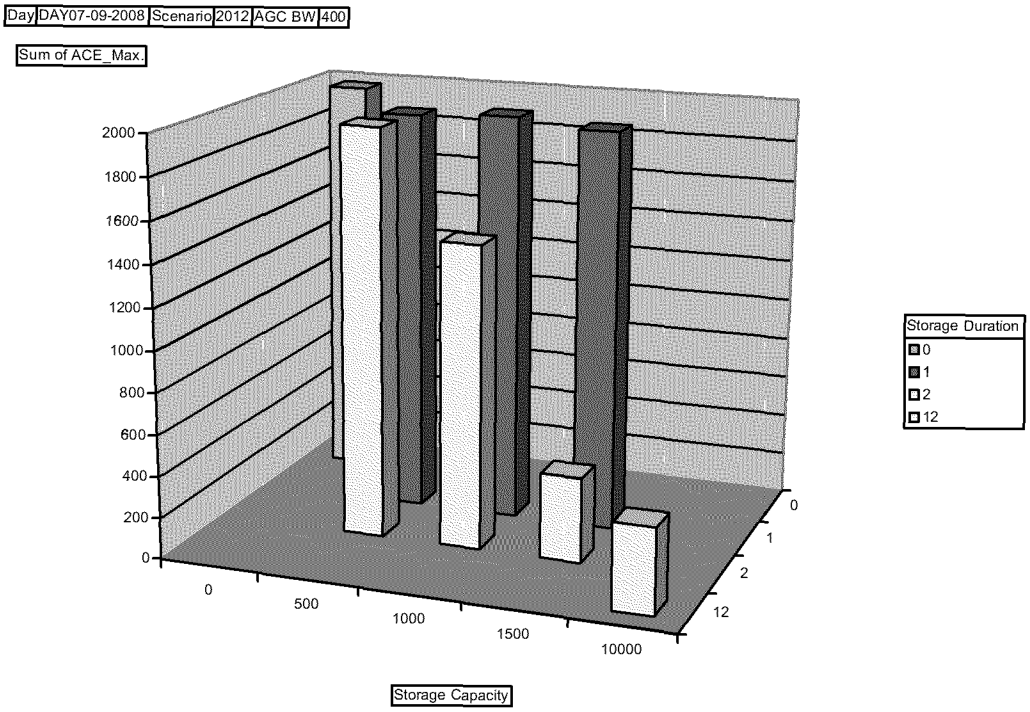

Figure 37. ACE maximum for July 2012 scenario with different amounts of storage at different durations

Source: model output

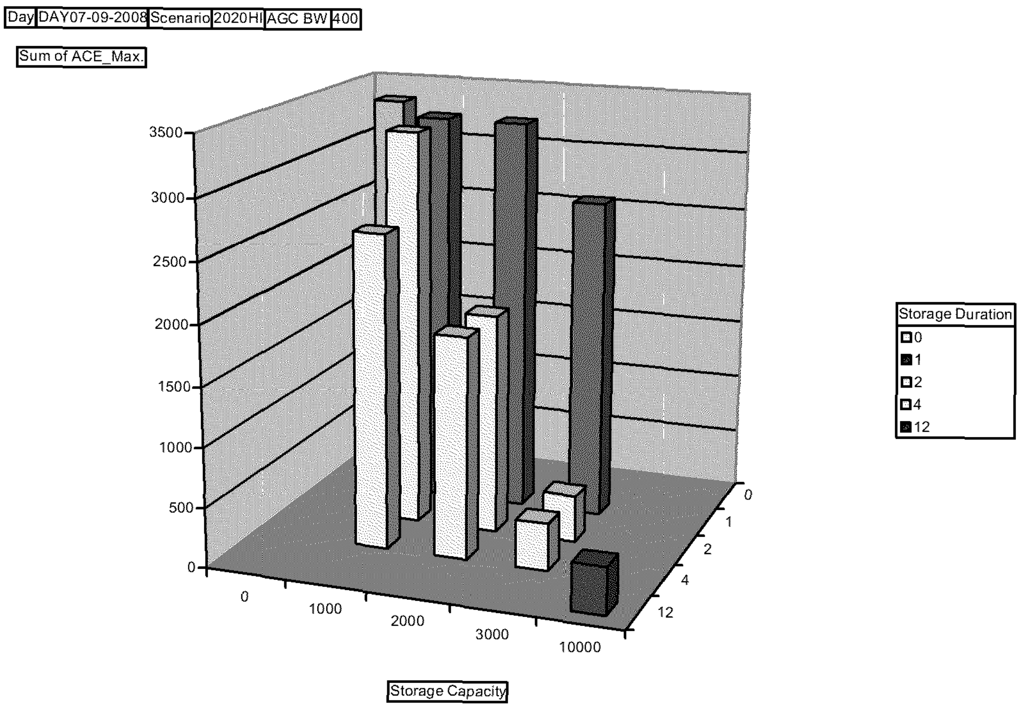

Figure 38. ACE maximum for July 2020 High scenario with different amounts of storage at different durations

Source: model output

Lower amounts of system storage than *required* to maintain ACE within today's norms will result in good ACE performance during periods when the renewables are not ramping severely but will show degraded ramping performance. This is shown in Figure 39, which illustrates ACE in the July 2020 High scenario with 1,000 MW, 2,000 MW, and 3,000 MW of 2-hour storage and no regulation.

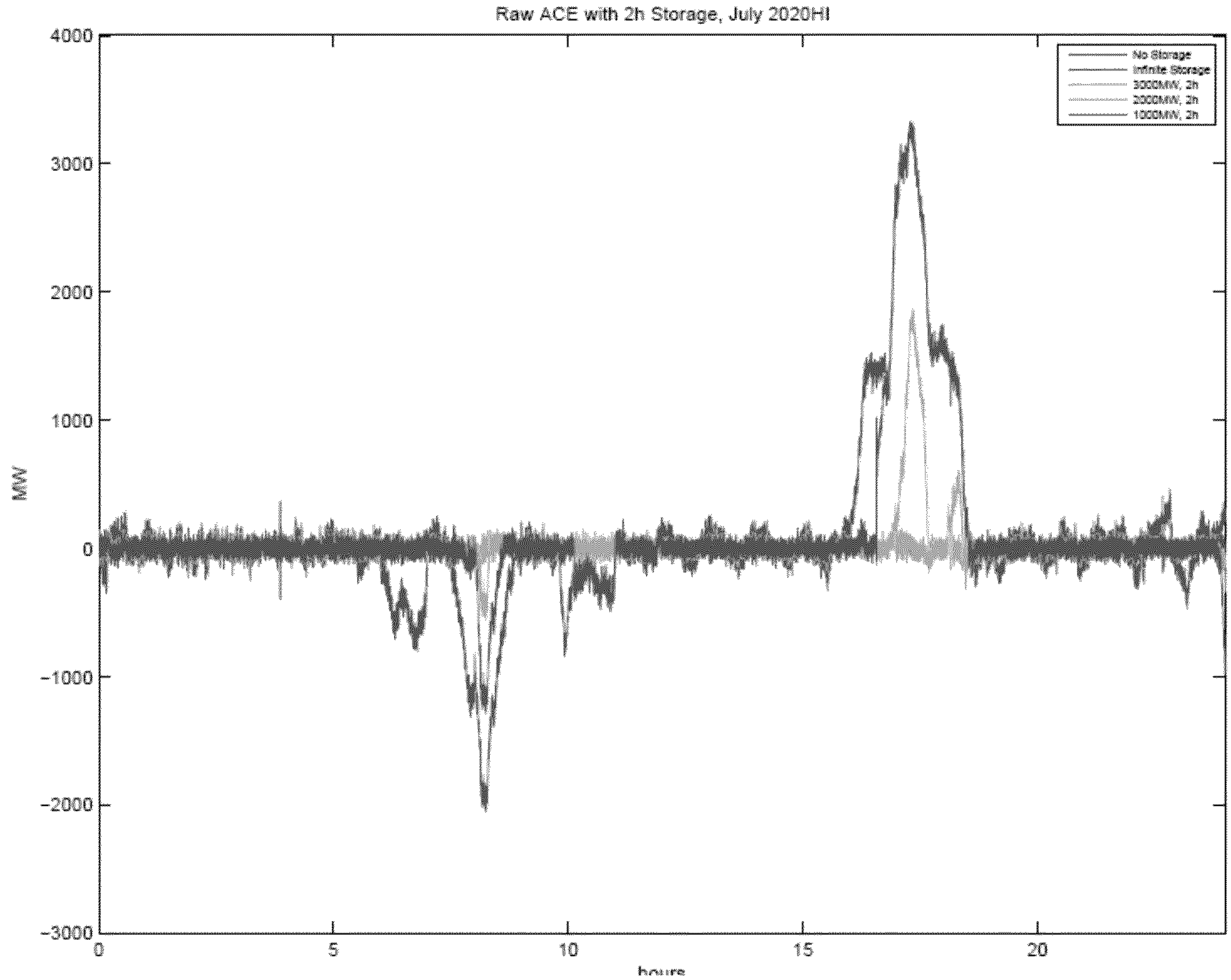

Figure 39. ACE performance with varying amounts of storage for July 2020 High scenario
Source: model output

Another way of measuring system performance is the NERC CPS1 metric. The California ISO has a goal of maintaining a daily CPS1 of 180 or better. Figure 40 shows how CPS1 varies with storage size configured for AGC, in conjunction with differing amounts of regulation procured. The CPS1 statistic, while sensitive to large ACE excursions, is also a measure of general ACE performance. This graph indicates that even with large amount of regulation applied (2,400 MW), 3,000 MW of storage is essential.

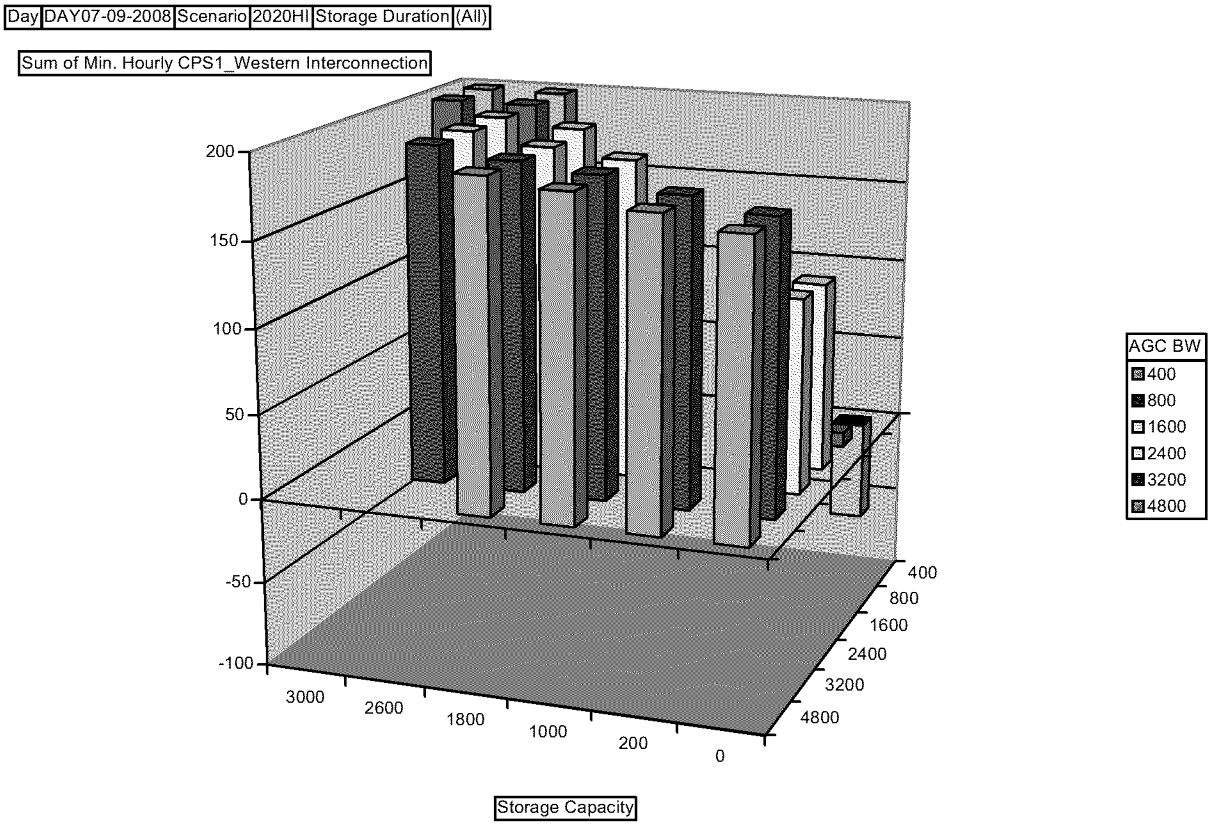

Figure 40. Minimum CPS1 across different amounts of storage and regulation for July 2020 High scenario
Source: model output

This point raises the question of how storage size and increased AGC regulation (or other approaches) relate to each other and work in conjunction. This was addressed at length in Task 3.7 where tradeoffs between storage size and regulation MW (and other parameters) were explored.

During *normal* operations, that is between ramp periods (10 AM to 4 PM) as described above, the regulation required is less, and the storage required is still less. The results of analyses of this aspect are shown inTable 6. As can be seen, storage is more effective than regulation and requires lower increments of storage than of regulation.

Table 6. Comparison of system performance with regulation and storage

Scenario	Performance Across Regulation Levels With No Storage				Storage Added to 400 MW Regulation			
	Regulation amount (MW)	Worst max ACE (MW)	Worst frequency deviation (HZ)	Worst CPS1	Storage amount (MW)	Worst max ACE (MW)	Worst frequency deviation (HZ)	Worst CPS1
2012	400	477	0.0470	184	200	311	0.0438	195
	800	325	0.0425	195				
	1,600	316	0.0424	196				
2020 Low	400	690	0.063	173	400	493	0.0609	190
	800	480	0.061	190				
	1,600	480	0.061	194				
	2,400	480	0.061	194				
2020 High	400	950	0.062	141	1,200	344	0.059	196
	800	662	0.061	172				
	1,600	480	0.061	191				
	2,400	382	0.061	191				
	3,200	382	0.061	191				

Source: model outputs

3.6. Requirements for Storage Characteristics

The key parameters for system storage are the power level, the duration or energy capacity, and the rate limit on changes to power output. As described above, these were evaluated, and it was determined that the California ISO control area has maximum benefit from (a) 3,000 MW of storage power capacity with at least (b) a two-hour duration and that the (c) ramping capabilities have to be 10 MW/second or greater.

The 10 MW/second requirement translates to achieving 3,000 MW of output from zero in five minutes. Thus, if there is 3,000 MW of storage with a 5 MW/minute ramp capability (and a 2 hour duration) it would seem that there is a need for faster storage capable of making up the 1,500 MW deficiency that accrues at the end of five minutes – so that 1,500 MW of 10 MW/second storage is required, but with less duration. (Much less; it would need to produce a ramp down over the next five minutes; so that the total energy would be 125 MW hours; e.g. the duration is 125 MWh/1,500 MW or 5 minutes. A similar set of mathematics can be performed for any combinations of technologies with differing rate limits. This implies that a lower capacity cost technology such as CAES can be combined with high performance and higher cost technology such as Li-Ion batteries or super-capacitors.

As a practical matter, it might be better for the storage provider to provide the mix of technologies so as to meet the MW/second requirement as a percent of power capacity and also meet the duration requirement overall. As commented above and visible in Figures 34 – 35, the efficiency of the storage system is not a performance requirement for regulation and ramping requirements but is a cost factor due to the energy losses. The rate limit performance of the

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storage system overall is a critical parameter. As noted above, researchers assessed system performance for differing rate limits on the storage. The storage system must have an aggregate rate limit of at least 5 MW/second for a 3,000 MW aggregate system, and 10 MW/second is preferable. (10 MW/second out of 3,000 MW equates to 0.33 percent/second or 20 percent/minute in general).

3.7. Storage Equivalent of a 100 MW Gas Turbine

A key policy question in developing a portfolio of renewable integration solutions is, how does equivalent storage compare to an investment in a new gas turbine for the same service? Storage is more expensive per MW provided, and it has a limited amount of energy it can supply to the system. A gas turbine, on the other hand, can continuously inject energy to system as long as it has a fuel supply. To help assess the question of whether a gas turbine provides more benefits for less money, researchers determined the rough equivalency of storage by examining the incremental impact of a single additional 100 MW CT. In particular, researchers evaluated the system performance impact of 100 MW of incremental CT dedicated to regulation and load following and compared that with the incremental impact of storage systems of different sizes.

Earlier attempts in the project to establish an equivalence between an incremental 100 MW of storage and an incremental 100 MW of regulation had produced some interesting results but were not the same as a direct equivalent to a single unit. This is because incremental regulation is spread across all units on regulation – in the modeled cases, this included all hydro and all CTs. Thus, each unit contributes very little, and unit ramp rate limits will come into play only in the most extreme ramping conditions, not during normal operations.

It was necessary for this comparison to be assured that the additional regulation signal enabled by the incremental turbine would be allocated to that turbine, and to use less *optimistic* allocation of regulation to the units. Therefore, an allocation of *regulation available* was made to the hydro and CT units such that CT units were providing about two-thirds of the total. The hydro units each had 18 MW of regulation assigned, and the CTs each had 15 percent of capacity. Only the larger CTs were allocated regulation; the small units of less than 100 MW were not allocated any. The total *available* (which also enforces that reserves will be at least this much) came to 1,000 MW from the hydro units and 2,500 MW from CTs.

A set of *baseline cases* for July and April 2020 were run where the amounts of AGC regulation used were 800 MW, 1,600 MW, 2,400 MW, and 3,200 MW. It should be noted that in the July scenario 3,200 MW of regulation is almost *enough* to bring maximum ACE to current levels (610 MW max versus less than 400 MW normally). However, that amount in April was insufficient.

Then one CT with a capacity of 110 MW with 50 percent of capacity allocated to regulation was added to the mix. This CT had a very high rate limit – 120 percent of capacity in 5 minutes. (The large CT units (over 500 MW) are significantly slower. The very small units are this fast or faster). The *baseline cases* were rerun with this CT added, and the improvement in various metrics (maximum ACE, maximum frequency deviation, and minimum CPS1) were noted.

Then, instead of the CT, storage units of 50 and 100 MW were added to the model, and the test cases were repeated. Again, this was run twice. As expected, the 50 MW storage unit produced benefits similar to the CT in some cases and varied in others. The 100 MW unit exceeded the metrics improvement of the CT by far. The three data points (two for storage, one for CT) were used to linearly extrapolate the size of a storage unit that provided numerically similar benefits to the CT.

Figure 41 illustrates that the equivalent size storage unit varied from approximately 30 MW to 50 MW. That is, on this incremental basis *a storage unit is two to three times as effective as an incremental CT*. The July day shows greater benefits probably because the system is more manageable on that day. On the April day, the ranges of regulation available are seriously insufficient, and the rate limit capabilities of the storage are not as important as the total MW – thus the ratio of storage to CT approaches the 50 to 100 ratio due to the ability of the storage to both inject and draw power.

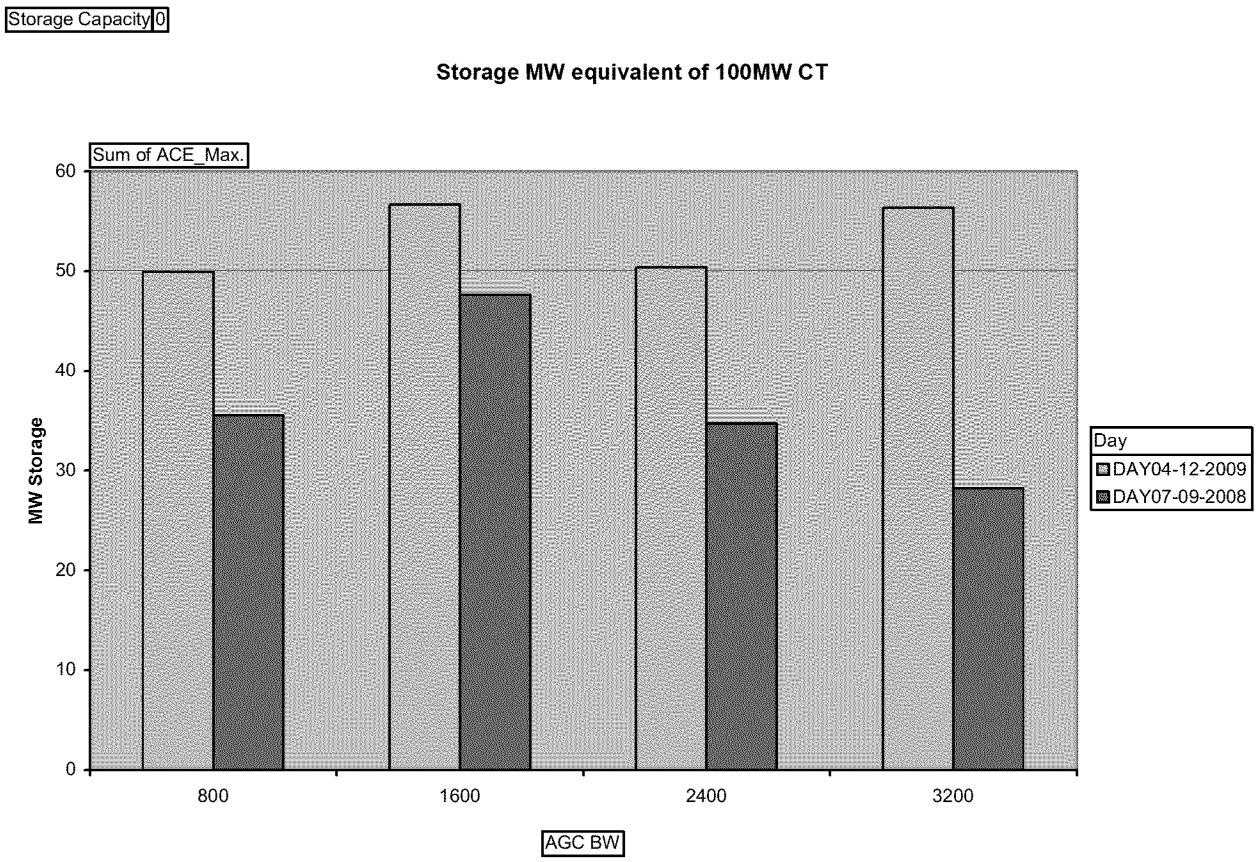

Figure 41. Comparison of storage to a 100 MW CT

Source: model output

The ratio of storage to CT is extremely non-linear. At the extremes, when there is already 3,000 MW of storage in use for example, the incremental benefit of either approaches zero. Thus, a range of conditions was used to establish this metric.

3.8. Issues With Incorporating Large Scale Storage in California

The results of this report indicate that renewable ramping creates volatility in the system and that storage has the technical potential to help address this volatility. However, key policy questions are how to best promote various ramping solutions and how to account for tradeoffs among them. Imposing ramping limits on renewable resources as an interconnection requirement would address volatility and leave open the question of which solution to use (storage, combustion turbine, or other means). Resource ramping limits are feasible for the *ramp up* phenomena (at some lost energy production), but not for the *ramp down,* which is technically difficult (requires storage in some form either at the resource or at the system level). Requirements could promote self-provided ramping management or might allow procurement from other resources or the California ISO markets. However, compared to other solutions, storage appears to have benefits and may be preferred in some instances.

Without storage, CT ramping would need to increase. This has three basic impacts:

- Increased maintenance costs and reduced lifetime from additional wear and tear
- Postponed de-commitment of CT units
- Increased GHG emissions

Storage could absorb the volatility and limit CT ramping, diminishing these adverse impacts. Though storage units are more expensive than CTs, the avoided emissions and wear and tear may make the incremental cost worthwhile. Additional research needed to assess additional CT maintenance costs and to value emissions reductions. Figure 42 and Figure 43 show the benefits storage has for both CT and hydro generators in terms of reduced ramping in response to renewables. As the amount of storage increases, the amount of unit ramping decreases.

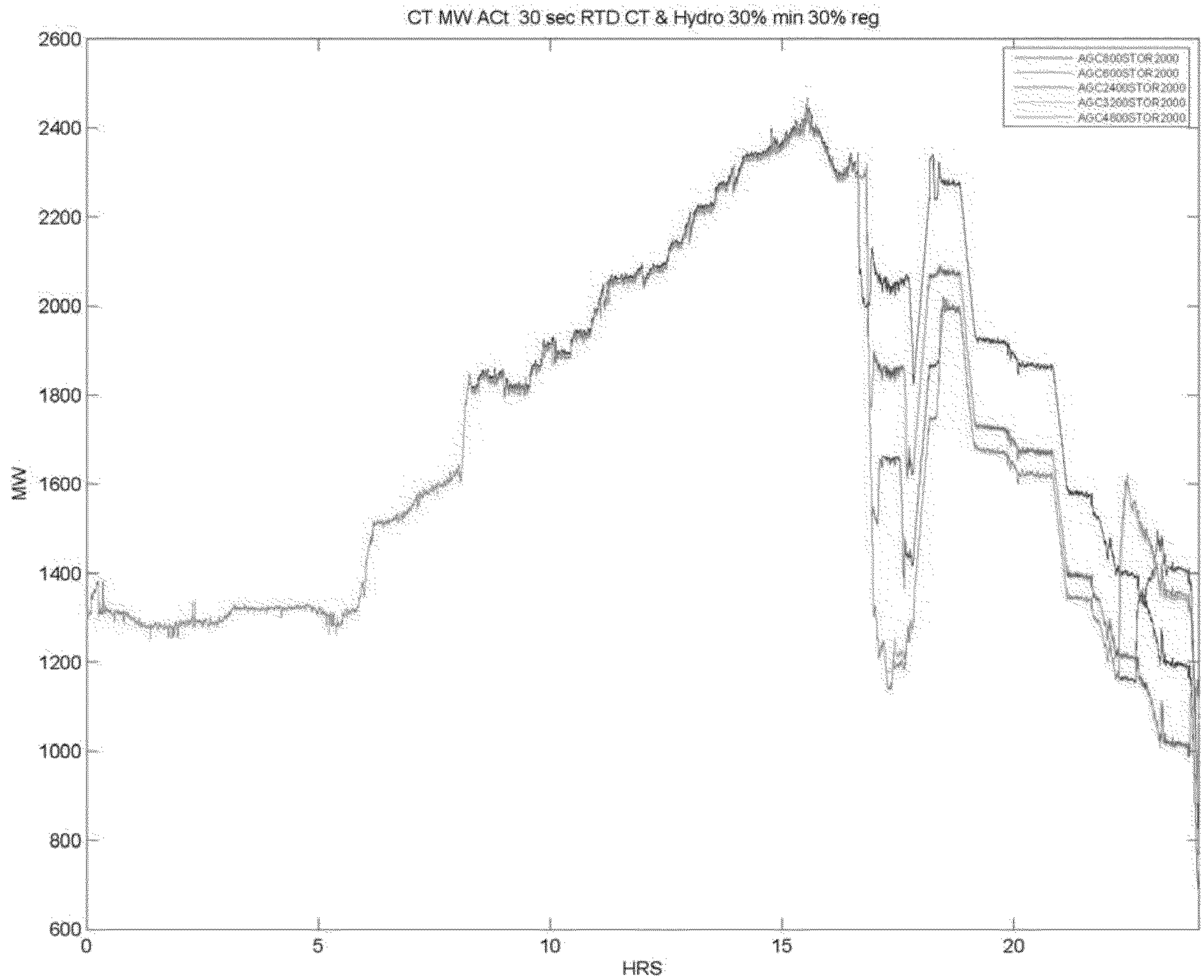

Figure 42. CT output at different levels of regulation
Source: model output

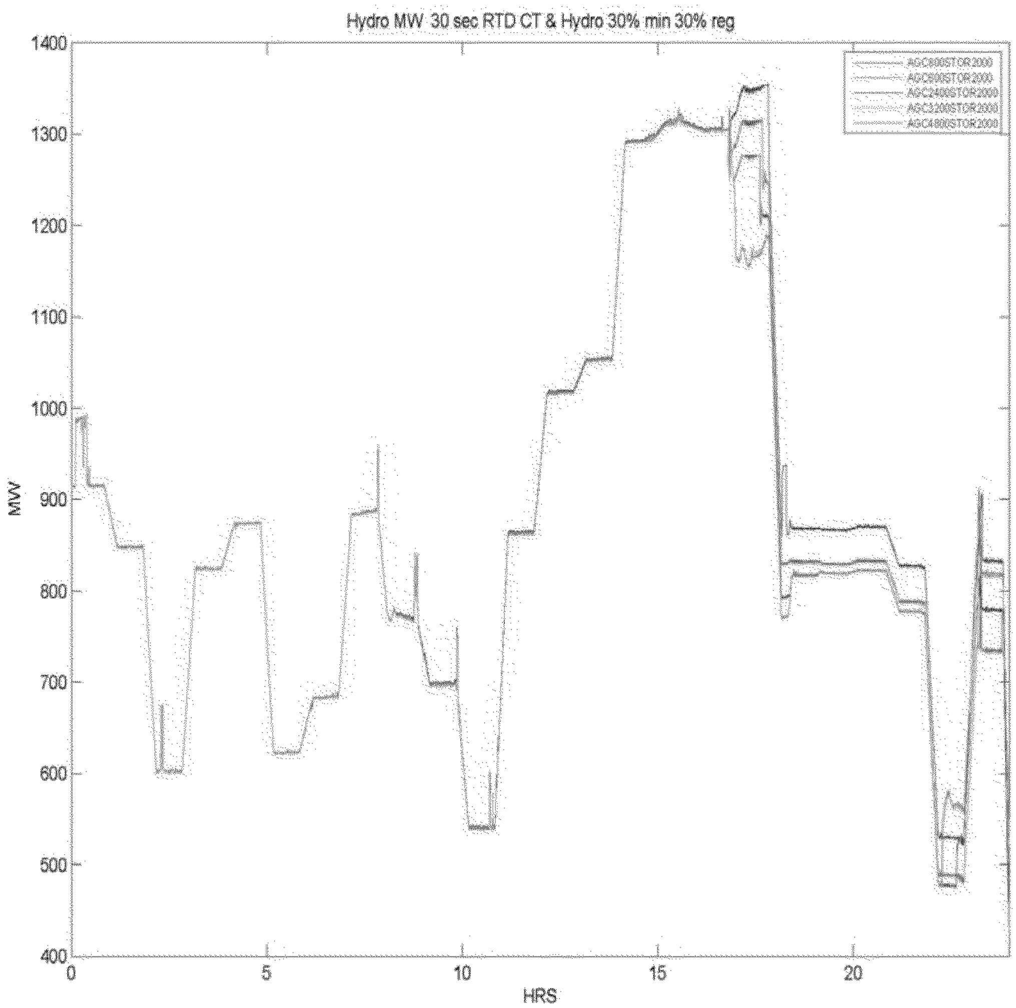

Figure 43. Hydropower output at different levels of regulation
Source: model output

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Excessive ramping up and down of hydro units has environmental implications for downstream water levels and may even by impractical in extreme cases.

Keeping the CT units on in order to provide regulation has an emissions impact. This is shown in Figure 44.

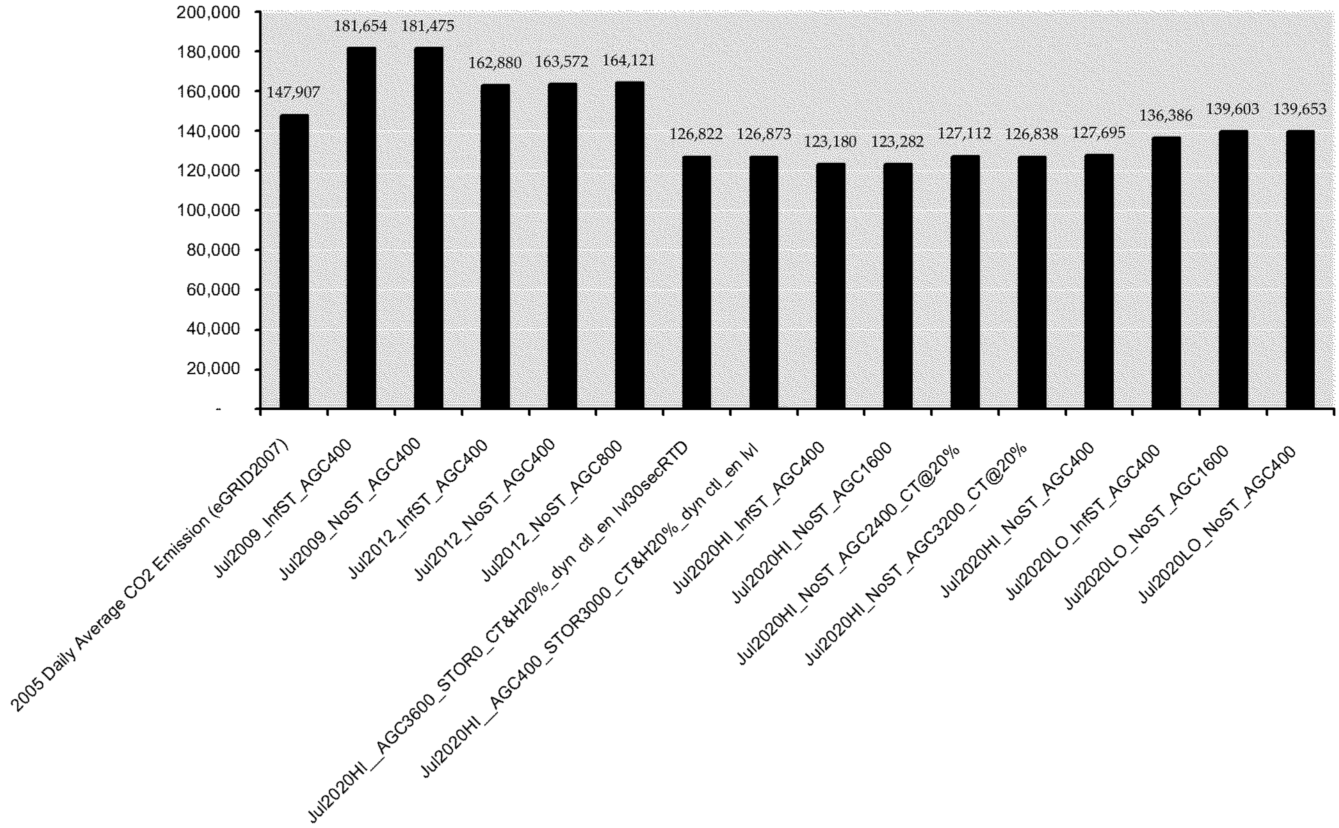

Figure 44. CO2 emissions in U.S. tons, by scenario
Source: model output

The most meaningful comparison of these many cases is the comparison between the no storage AGC 3,200 MW case in 2020 and the Infinite Storage case for that year. This shows that greenhouse gas emissions increase approximately 3 percent for that day – as a result of the forced dispatch of the combustion turbines to provide regulation in the first case.

The acquisition of regulation and ramping services from storage in the amounts identified will be a significant cost to the system. How these costs will be allocated – either to the entire market as an ancillary service or to renewable resources in effect by imposition of ramping rate limits has profound economic implications for renewable developers and the future economic viability of renewable resources.

4.0 Conclusions and Recommendations

4.1. Conclusions

There are five major conclusions from this research work:

- The California ISO control area will require between 3,000 and 4,000 MW of regulation / ramping services from "fast" resources in the scenario of 33 percent renewable penetration in 2020 that was studied. The large ramping requirement is driven by the combination of solar generation and wind generation variability that is forecasted for the 33% scenario. Some of this ramping requirement can be satisfied by altering the likely system commitment for conventional generation to maintain a large amount of gas fired combustion turbines on-line available for ramping. It also may be possible to alter the scheduling of hydroelectric facilities and pump-storage facilities so as to assure adequate ramping potential at critical periods, although there are environmental and operational difficulties associated with this.
- The moment by moment volatility of renewable resources will require additional AGC regulation services in amounts (up to doubling today's levels) that can be reasonably procured.
- The ramping requirements twice a day or more require much more response and will be the major operational challenge.
- Fast storage (capable of 5 MW/second in aggregate) is more effective than conventional generation in meeting this need and carries no emissions penalties and limited energy cost penalties.
- Use of storage also avoids greenhouse gas emissions increases associated with scheduling combustion turbines "on" strictly for regulation and ramping duty.

An alternative to providing large-scale fast system ramping is to constrain the ramp rates of wind farms and central thermal solar plants so as to reduce the need for system ramping resources. This is an interconnection requirement in some island systems today. Meeting ramp rate limits on *up* ramping is easy enough to do at some lost energy production; meeting down ramp requirements is more technically difficult.

Storage at the site of the renewable resources or as a market service that renewable producers can acquire is an alternative to a system ancillary service with identical benefits and results. There are a number of policy issues at the state and federal level around this concept today which are elaborated in the report. The most important is to determine if ramping restrictions and support are the financial responsibility of the renewables operator or the market; and related to that what storage investments will qualify for what investment tax credits and how these are linked to renewables facilitating increased renewable generation.

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The study identified some successful control algorithms and protocols to use for system storage resources for regulation and ramping. These can be evaluated by the California ISO for implementation if system storage is pursued as an ancillary service resource. This is not to say that these algorithms are definitively the optimum that may be developed; future R&D on advanced control strategies linked to wind and solar power forecasting is still very much worthwhile. Nevertheless, these algorithms imply that it is certainly worthwhile for the California ISO to explore implementing a new market product for fast storage services for regulation and load following.

The study examined the benefit of changing the periodicity of the real time dispatch function from 5 minutes to 30 seconds. This did not provide the benefits anticipated due the very high ramp rates experienced in the evening when central thermal solar ramps down very rapidly. Altering the droop settings of conventional generators was of no benefit to system regulation or ramping. A separate effort to assess the need for altered droop settings as a result of decreased conventional generation on-line may be in order, along with a study of system transient response due to lowered inertia. Neither of these is regulation or load-following effects.

The accommodation of 33 percent renewable generation resources is the goal established by the Governor for the state. To achieve this goal will require major alterations in system scheduling and operations under current paradigms, which will be costly in terms of energy costs and GHG emissions. The use of storage in conjunction with new control and ramping strategies offers a way to avoid these costs and provide current levels of system reliability and performance at lower risk. While it is yet to be investigated, storage also promises to be a useful tool in making use of DR as an additional ancillary service provider to facilitate renewable integration.

The 3,000 to 4,000 MW of storage which could be used to address renewables management requires a ramp rate capacity of 5 to 10 MW/second, or 0 to full power charging / discharging in 5 minutes. This equals or exceeds the ramping capabilities of most conventional generating units, and particularly the larger combustion turbines. Smaller combustion turbines in the California ISO database can meet this ramp rate requirement, but there are insufficient quantities of such units to provide the required 3,000 to 4,000 MW of fast ramping. Hydroelectric units are capable of changing output levels at these rates. However, it is unclear if the hydroelectric units have sufficient range available for regulation at these levels without having to operate in hydraulic forbidden zones. The hydro units also have very limited amount of water available in the fall and winter months, so they are not available as a regulation resource during a number of months. A parallel 33 percent renewables study is investigating the scheduling and dispatch implications of providing sufficient ramping and reserved requirements, and its results should be integrated with the results of this study for further analysis.

A duration of two hours for the storage systems was found to be sufficient for the regulation, ramping and load following applications.

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The measurement of the relative effectiveness of storage to a combustion turbine demonstrates that, depending upon system conditions and other factors, a 30 to 50 MW storage device is as effective as a 100 MW CT used for regulation and ramping purposes. This is an incremental figure measured across a range of system scenarios; that relative performance figure of merit would not obtain across the entire range of regulation resources 0 – 5,000 MW of course.

4.2. Recommendations

This section outlines recommendations resulting from the analysis described above. The research team recommendations fall into two categories: additional research growing out of this study and policy issues.

4.2.1. Recommendations on Additional Research

Table 7 summarizes additional research recommended by the project team. The following text describes this in detail.

Table 7. Additional research recommendations by project team

Research Recommendation	Rationale
Add additional days to the sample	Obtain results that reflect a larger sample of days to understand the statistical behavior and extremes in renewable volatility and ramping.
Examine geographic and temporal diversity of renewables	Understand the statistical behavior and extremes in renewable volatility and ramping.
Assess the impact of external renewables	- The analysis made no assumption about external renewables or behavior. - The characteristic of renewable imports may impact frequency deviation.
Develop dynamic models for CS plants including gas co-firing, thermal storage, and electrical storage possibilities	- CS ramping was identified as a major challenge. Understanding how it may be managed is central to understanding the tradeoffs involved in addressing ramping.
Develop dynamic models for other types of solar plants including Sterling Engines and Large PV installations.	- New types of solar plants will have different ramp up and down characteristics and operating characteristics. These models should be included in the build out scenarios for 33 percent renewables.
Validate ancillary service protocols for storage	- Future R&D on advanced control strategies linked to wind and solar power forecasting is worthwhile. - This will affect the R&D and engineering directions taken by the grid storage industry.
Assess the market implications of procuring very high levels of regulation/reserves as may be required	Changes to market protocols may be advisable.
Continue Development of the California ISO AGC algorithms for Storage and real-time demand response.	The algorithm developed considers a single aggregated storage resource. At a minimum, a simple algorithm to allocate regulation/load following to individual resources using that signal, and to update the status of each individual resource (energy level) into that algorithm, is required.

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Research Recommendation	Rationale
Conduct a cost analysis for solution alternatives.	This report looked at the technical potential of storage only. Cost considerations will weigh into how to balance different options.
Examine the use of DR as an additional ancillary service to facilitate renewable integration, and potentially the use of storage.	- It is not yet apparent that DR programs could provide the high-speed response required to manage renewable ramping that grid connected storage can. If it turns out that the benefits of rapidly responding DR are important in making DR useful for accommodating renewables, then that knowledge will be important in the design of smart grid capabilities for DR and the associated protocols.
Conduct a WECC-wide study and include the impact of the proposed changes to the NERC BAL standards and the potential approval of a Frequency Response Requirement (FRR) for WECC Balancing Areas.	- It may be that NERC will have to re-examine CPS criteria in light of high renewables levels and establish new goals appropriate to the interconnections and the anticipated geographic diversity of renewables as well as what frequency deviation and tie deviation the interconnection can tolerate. - This research maintained control area performance at today's levels. - What realistic limitations on system performance (ACE, frequency deviation, NERC CPS) should be considered in developing protocols and needs for storage and renewables balancing.

Source: Authors

The study did not examine the potential to use DR as an ancillary service associated with the ramping phenomenon as another means of mitigating the impact of renewables. While it seems intuitively obvious that DR could provide similar benefits as storage, it is not apparent that DR programs can meet all the requirements of the ISO to provide the high-speed response required to manage renewable ramping similar to grid-connected storage. A second phase to this study is recommended to investigate DR in conjunction with storage and to examine the response rate potential of DR under different smart grid strategies. If it turns out that the benefits of rapidly responding DR are important in making DR useful for accommodating renewables, then that knowledge will be important in the design of smart grid capabilities for verifying the DR response. It should be noted that the greatest need for DR occurs at times of the day when economic and domestic activities are themselves *ramping up* and that achieving the needed levels and responsiveness of DR may be challenging. This is not DR for peak shaving to reduce peak energy prices but is DR for ramping mitigation with different time frames and ISO performance requirements.

The acquisition of regulation and ramping services from storage in the amounts identified will be a significant cost to the system. How these costs will be allocated – either to the entire market as an ancillary service, or to renewable resources in effect by imposition of ramping rate limits, has profound economic implications for renewable developers and the future economic viability of the renewable resources. Development of the business and regulatory models for this problem are not part of this study but need to be examined so that an informed policy

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debate can take place. The development of the ancillary service protocols for storage will definitely affect the R&D and engineering directions taken by the grid storage industry and need to be validated and made known as soon as practical. For instance, the two-hour duration requirement is a significant parameter that will affect which storage technologies are *in play* or not. Similarly, the ramp rate requirements for grid storage in this application will have implications for the technologies developed and deployed. A careful study of the implications of acquiring very large amounts of regulation / reserves / load following via the market is in order. A careful analysis of how deep the regulation market is and whether units capable of fast regulation should be treated as having market power may also be in order.

The California ISO is considering changes to the market and the energy management system to integrate several hundred MWs of limited energy storage resources such as flywheels and batteries in the regulation market. These devices typically have very fast response rates and can switch between charge and discharge modes within 1 second. They also have very limited amount of energy storage capability, typically 15 minutes of energy, and therefore require constant monitoring to ensure they can continue to provide their full regulation range and are energy-neutral over a 10 to 15 minute period. The proposed AGC dispatch algorithm changes should also include models for these devices and include an energy replacement control loop.

There are a number of secondary results from the study – investigation of control algorithms for instance, which also need to be subject to broad industry review and validation and then developed appropriately by the California ISO for implementation. Where appropriate, market products have to be designed and tariffs filed.

The study was *optimistic* in one critical way – the impact of large forecast errors for renewable production, especially forecast errors associated with wind production, was not studied. The wind forecast errors assumed in the scheduling and dispatch were as actually observed on the studied days in 2008-2009 and were not significant. Addressing larger wind power forecast error problems will further emphasize the benefits of storage as compared to conventional generation used for regulation as these units would have to be kept on for longer periods in order to provide against forecast error.

The study observed wind, PV, and CS production for simulated days across the seasons and then scaled these up for the 2012 and 2020 renewable scenarios. This methodology was the only practical approach in the time frame with the data available to the California ISO. As such, it tends to reduce the impact of geographic diversity on the renewable ramping characteristics. While data across the West Coast seems to indicate that this geographic diversity is not as large a factor as might be thought, it will be an important point of discussion with the renewable community and needs further analysis. The California ISO is conducting an analysis of the correlations of wind power geographically today. The results of this could be used in another phase of this project that examines most or all of the days in a year so as to understand the statistics of system ramping requirements. Note that the system has to be able to withstand the expected worst case scenario for coincident ramping seasonally – it cannot be designed and operated for *averages* if there are significant probabilities of reliability-threatening coincident ramping.

Literally hundreds of second-by-second simulation of the California power system were performed for each of the four days and four renewable scenarios developed. These simulations produced the conclusions and results described above. The conclusions and recommended control algorithms and dispatch protocols need to be validated across a much larger sample of days than the four seasonal typical weekdays chosen.

The California ISO did not have available projected hourly schedules for the conventional generation against the different renewable scenarios nor could those have been practically adapted to various reserve and regulation levels studied were they available. As the projected hourly schedules for conventional units become available, these can be iteratively combined with the hypothetical storage and renewable ramping solutions to further validate and refine both the production costing and dynamic performance conclusions. The limited investigations that the project made of this topic showed that system performance varies with the allocation of regulation to conventional units in ways that vary from one day to the next, not always intuitively apparent. The interaction of energy scheduling, reserve and regulation allocation, and system performance when very high levels of regulation are procured is extremely complex.

The study used assumptions by the California ISO about how much of the state wind power would actually be purchased from wind developers located within the Bonneville Power Administration control area and how much of those resources would be *levelized and balanced* by BPA versus the California ISO. These assumptions will greatly affect outcomes and thus need to be monitored and adjusted as contracts are negotiated. Related to this is the conclusion in the study that the WECC system frequency is not at risk as much as the California ISO ACE, due to the size of the interconnection. However, if significant additional renewable resource penetration is assumed across the WECC, this result will be optimistic. Therefore, the extension of the study to broader WECC issues (where geographic diversity will have a larger favorable impact) is probably a topic for discussion between the California ISO and WECC.

Finally, the study scope did not include examination of the costs of either greatly increasing procurement of ancillary services or of deploying large amounts of grid connected storage. Such a cost benefit tradeoff requires forward projection of these costs, which is somewhat speculative. These cost benefit tradeoffs can be developed for hypothetical future developments on the economics (including carbon cap and trade) of conventional generation and of storage technologies. A commitment by the state to a single strategy using today's economics will not be as wise as a continuous adoption of strategies as costs and technologies evolve.

This research maintained control area performance at today's levels. It may be that NERC will have to reexamine CPS criteria in light of higher penetration of renewables and establish new goals appropriate to the interconnections and the anticipated geographic diversity of renewables as well as what frequency deviation and tie deviation the interconnection can tolerate. Towards this purpose, a WECC-wide study similar to this one is an advisable next step.

4.2.2. Policy Recommendations

There are three major policy recommendations that should be considered as a result of this study and several secondary issues are raised.

First, the likely resolution of how to manage the operational challenges of renewables will have four elements:

- Imposition of ramp rate limits on renewable resources on some basis.
- Utilization of fast storage for regulation and ramping either as a system resource or as a resource utilized by renewables resource operators.
- Procurement of increased regulation and reserves by the California ISO.
- Utilization of DR as a ramping / load following resource, not just a resource for hourly energy in the day-ahead market.

This study primarily investigated the first two of them. Follow-on efforts are recommended to study the effectiveness of ramp limits on renewables and the effectiveness of DR for load following are required before firm policy decisions can be taken. Also, introducing the need for these latter two elements will stimulate the market debate among parties affected. While the study does not offer research to support this assertion, it seems that ramp limiting renewables, if feasible, will be a key element.

Second, the use of fast storage as a system resource for renewables management appears to require technical performance characteristics of the storage, in particular ramp rate limits. If these are to be imposed as requirements for a new regulation ancillary service then the storage development community needs to be aware before large investments are made in technologies that are not capable of this performance.

Secondary policy issues are:

- Will storage be a resource tied to renewable installations; available as a merchant function in the market available to the renewable operator, or available only to the California ISO as an ancillary service provider? This question is linked to the question of whether to ramp limit renewables.
- As indicated by this study, procurement of very large amounts of regulation and reserves from conventional units may cause market distortions. If so, new market and regulatory protocols may be required.
- What incentives at the federal or state level are indicated to support storage resource development? And how should these be linked to renewable facilitation? It seems that storage should meet the technical performance characteristics identified in this report as validated and amended by the California ISO in order to qualify. The state may wish to communicate this concept to the U.S. Congress which is contemplating investment tax credits for storage.

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- This study used existing California ISO system performance criteria as the benchmark and developed regulation and load following requirements on the assumption that any significant degradation of these is unacceptable. However, NERC and/or WECC may establish new performance criteria developed with high RPS operations in mind.

Third, the Energy Commission should fund additional research on new energy storage technologies that can be integrated with large concentrated solar and PV installations. The goal is to reduce the variability of the solar energy production and to reduce the rapid and large ramp ups in the morning and ramp downs at sunset. Existing molten salt thermal storage is both expensive and operationally challenging. New technologies are needed now before the large solar plants are all designed and built.

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5.0 Benefits to California

The prospective benefits to California from the development of fast electric storage resources for use in system regulation and renewable ramping mitigation are significant. Specific benefits of fast storage include:

- Management of large renewable ramping as well as increased minute to minute volatility without degrading system performance and risking interconnection reliability.
- Management of renewable volatility and ramping without having to procure very large amounts of regulation and reserves, which may be either very expensive or infeasible.
- Reduced breakage and maintenance of the thermal and hydro generation fleet as they will be subject to less volatility and stress as the energy storage resources will absorb a lot of the rapid changes in energy production.
- Avoidance of keeping combustion turbines on at minimum or midpoint power levels to support regulation and load following.
    - Avoids increased GHG emissions.
    - Avoids higher energy costs due to combustion turbine energy displacing lower cost CCGT and/or hydroelectric energy.

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7.0 Glossary

ACE	Area Control Error
AGC	Automatic Generation Control
CAES	Compressed Air Energy Storage
California ISO	California Independent System Operator
CCGT	Combined-cycle gas turbine
CPS	Control Performance Standard
CPUC	California Public Utilities Commission
CS	Concentrated solar
CT	Combustion turbine
EAP I	*Energy Action Plan I*
EAP II	*Energy Action Plan II*
Energy Commission	California Energy Commission
GW	gigawatt
GWh	gigawatt-hour
IOU	investor-owned utility
kW	kilowatt
kWh	kilowatt-hour
MRTU	Market Redesign and Technology Upgrade
MW	megawatt
MWh	megawatt-hour
PIER	Public Interest Energy Research
NERC	North American Electric Reliability Corporation
T&D	transmission and distribution
VAR	volt-ampere reactive
WECC	Western Electricity Coordinating Council

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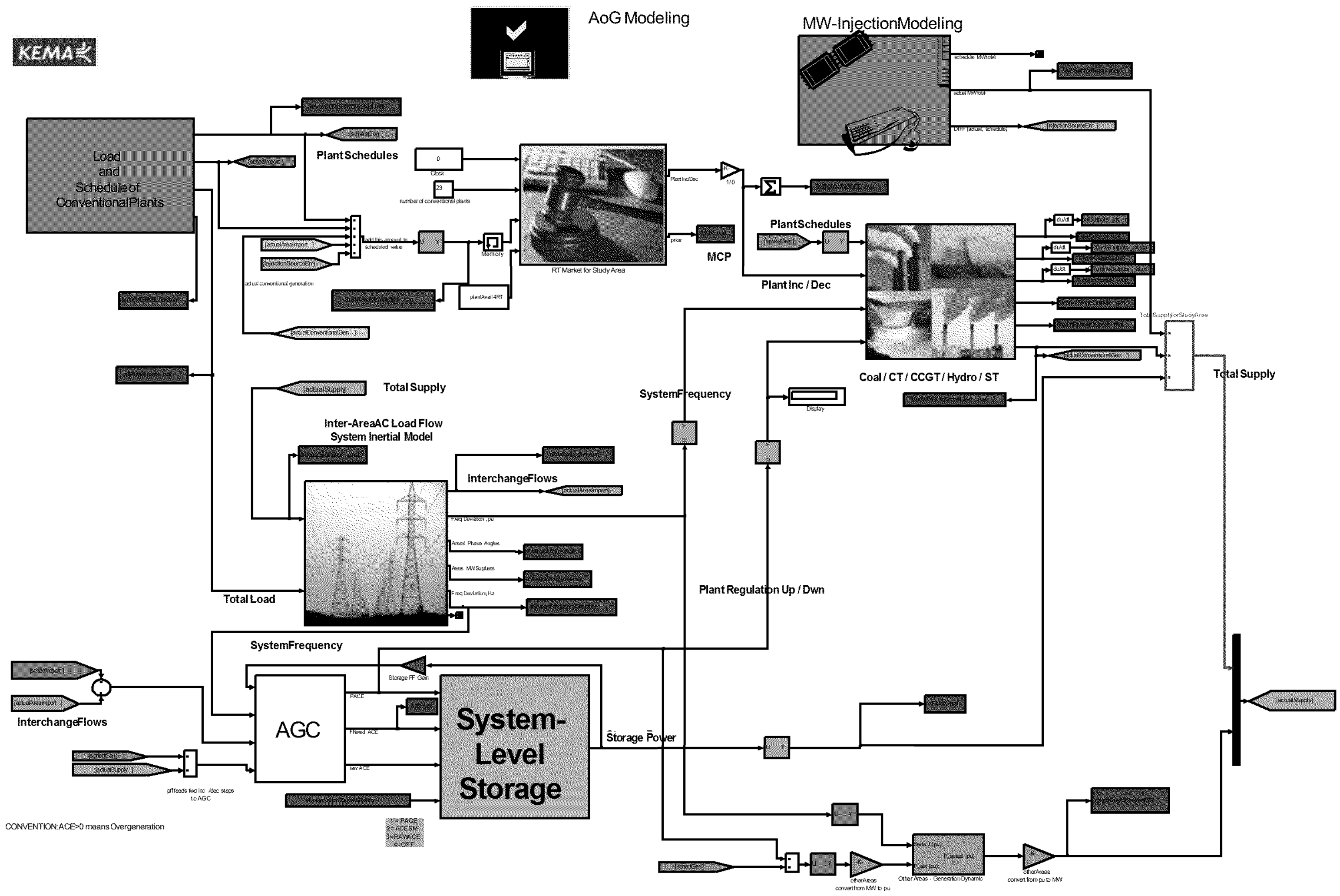
Appendix A: KERMIT Model Overview

The key elements of the simulator are shown in and include the following:

- Detailed IEEE standard dynamic models of a variety of generation types – including steam (coal or gas fired), CCGT, CT, hydro, and general distributed generation resources. These models include governor and plant controls, combustion systems and controls, steam and hydraulic effects, and turbine dynamics. The model incorporates wind farms and storage facilities.
- Models of generation company portfolio dispatch and scheduling.
- Representation of the dynamic frequency response of system load.
- Power system inertial response to generation-load imbalance and simulation of system frequency.
- Model of the interconnected control areas including a DC change to AC losses, load flow and swing angle simulation, control area AGC, dynamic load models, and interchange scheduling. The DC load flow dynamically simulates transmission path flows among control areas as the relative phase angles of the interconnected control areas respond to local and system generation – load imbalance.
- A generic AGC system that incorporates typical regulation services in a market environment, including various algorithms for regulation and control exploiting grid connected storage which are used to examine controls design.
- Representation of day – ahead hourly interchange and generation scheduling, load forecasting, and forecast errors. Hourly ramping behavior is also captured.
- Real time dispatch for balancing energy incorporating a market clearing function based on hour ahead bid stacks for inc/dec supply. The real time dispatch model is capable of look-ahead behavior using short-term load forecasting and anticipated generation response to inc/dec instructions.
- Settlements of real time energy based on inc/dec instructions and actual generation.
- Forecasting of distributed generation resources and forecast errors.
- Forecasting of wind velocity and direction and forecast errors. Wind *noise* is correlated in time and space across different wind farm locations. The incorporation of wind farm forecasting and actual production in generation company operations is represented. (Note: For this project this feature was not used as second by second wind farm production was available from the California ISO as a starting point.)
- Wind fall-off behavior and storm shut-off behavior of turbines. (Note: For this project this feature was not used as second by second windfarm production was available from the California ISO as a starting point.)
- Velocity to power conversion of typical wind turbines and turbine grid interconnection, although without fast electrical transient effects. (Note: For this project this feature was not used as second by second windfarm production was available from the California ISO as a starting point.)

A more detailed portrayal of the high level block diagram of KERMIT is shown in figure APA 1.

Figure APA 1. KERMIT diagram



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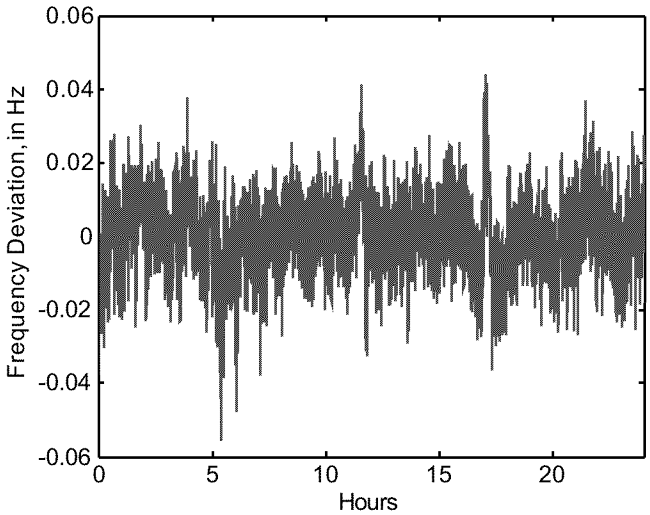
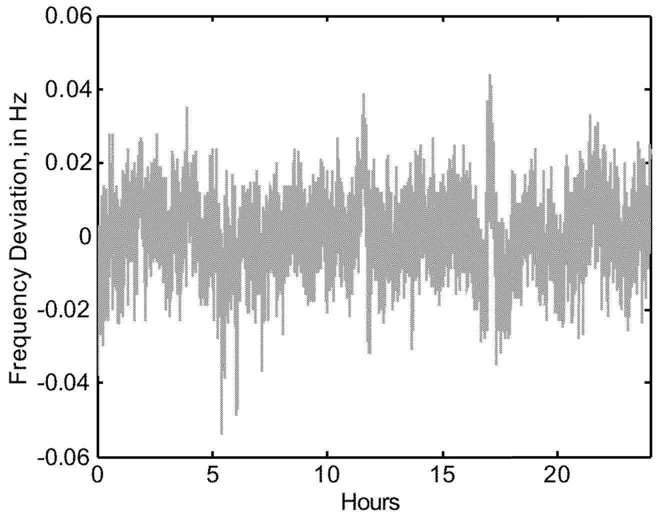
Appendix B: Calibration Results

This appendix contains calibration results for each of the days modeled. The graphs compare modeled versus historical data for frequency deviation and ACE. Figures on the left are the model outputs and those on the right are historical data.

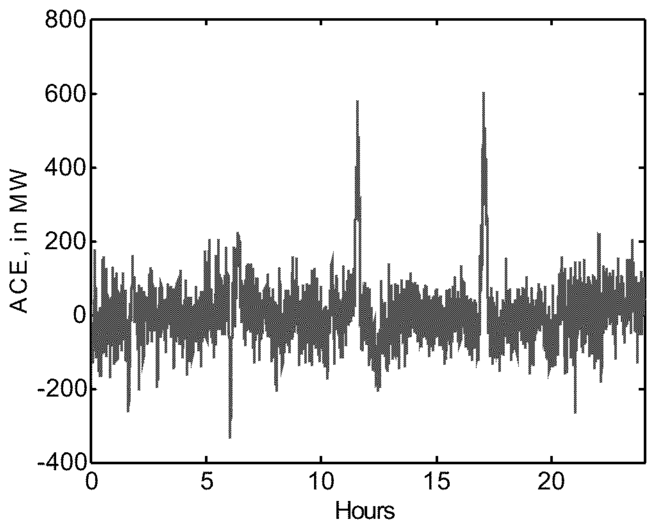
B.1 Monday February 9, 2009

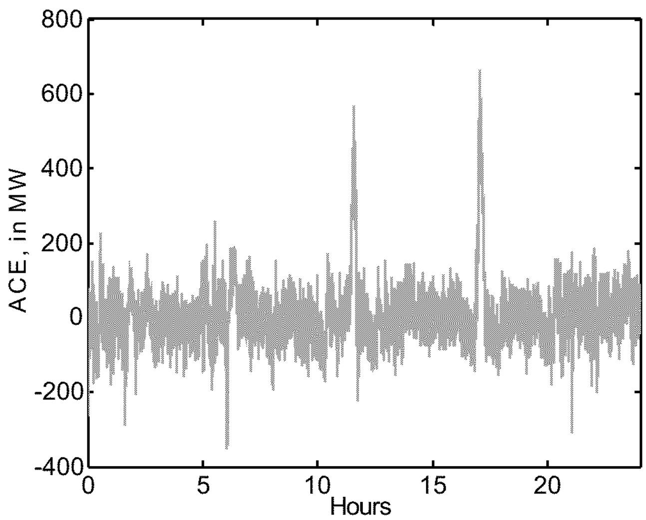
B.1.1 Frequency Deviation





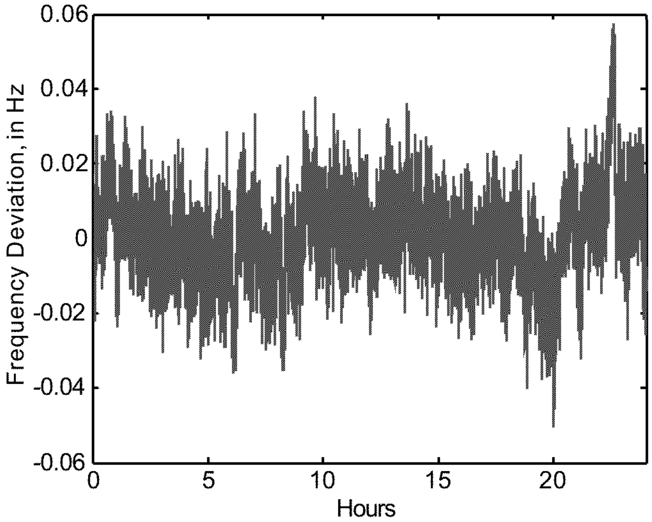
B.1.2 Area Control Error

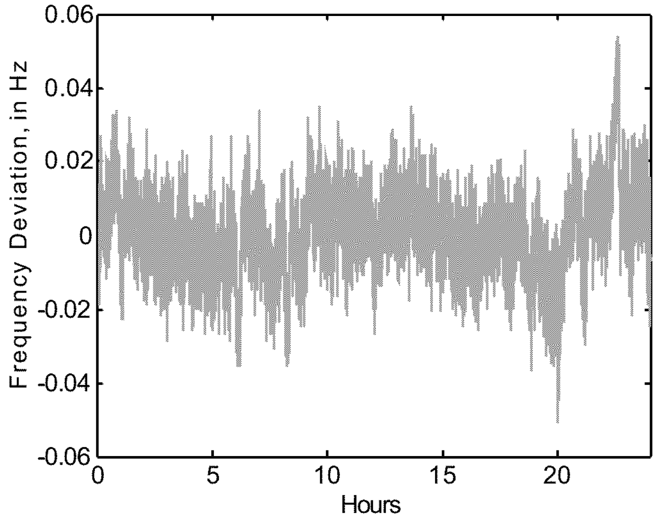




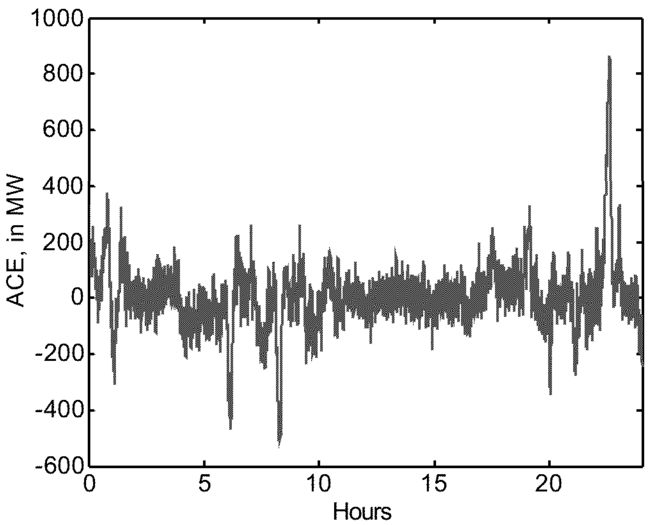
B.2 Sunday April 12, 2009

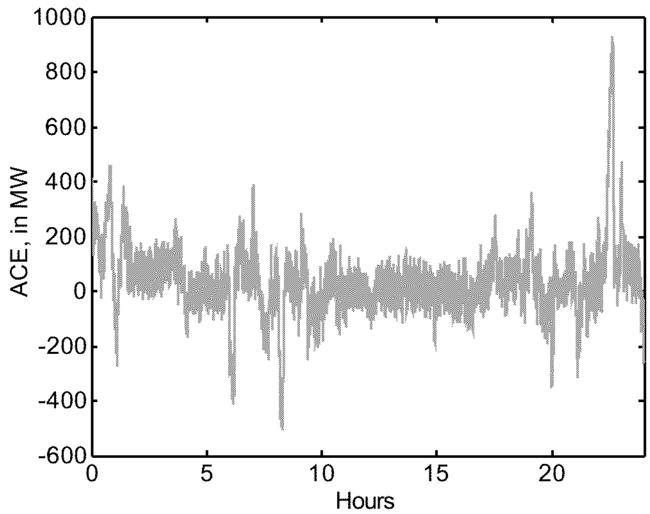
B.2.1 Frequency Deviation





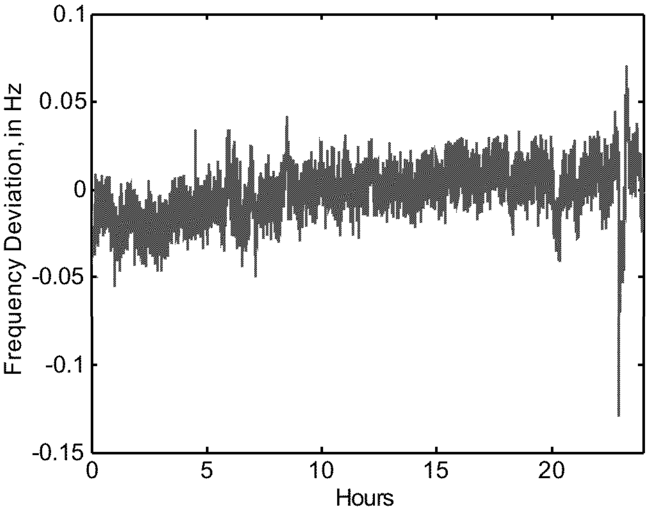
B.2.2 Area Control Error

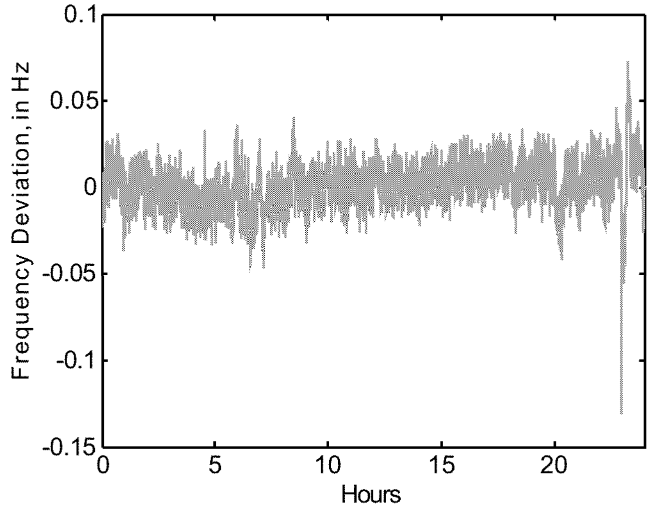




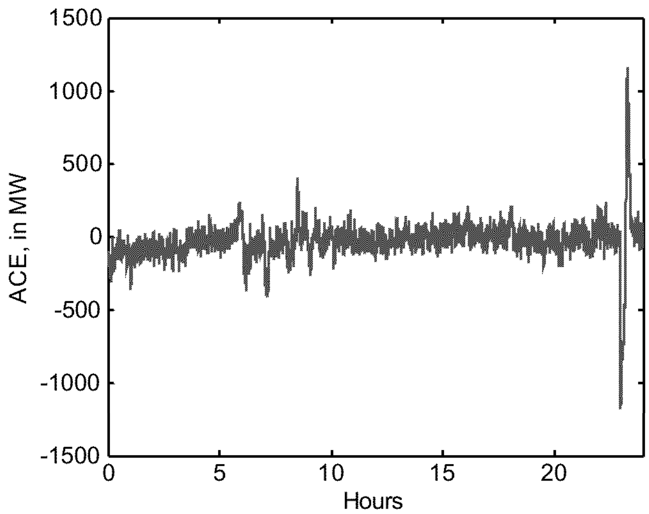
B.3 Monday June 5, 2008

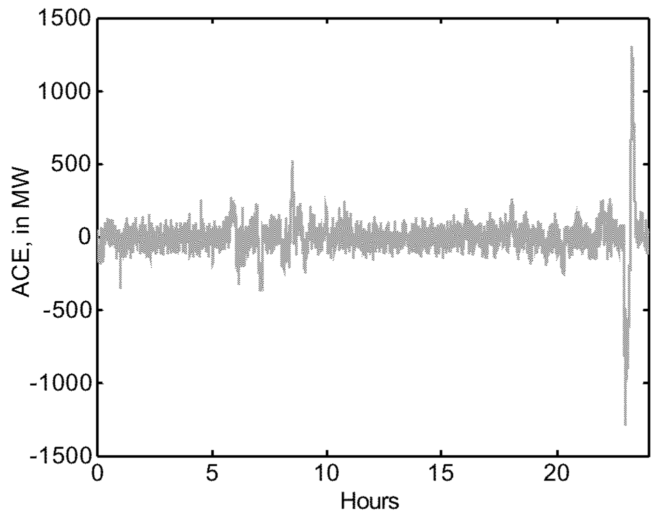
B.3.1 Frequency Deviation





B.3.2 Area Control Error

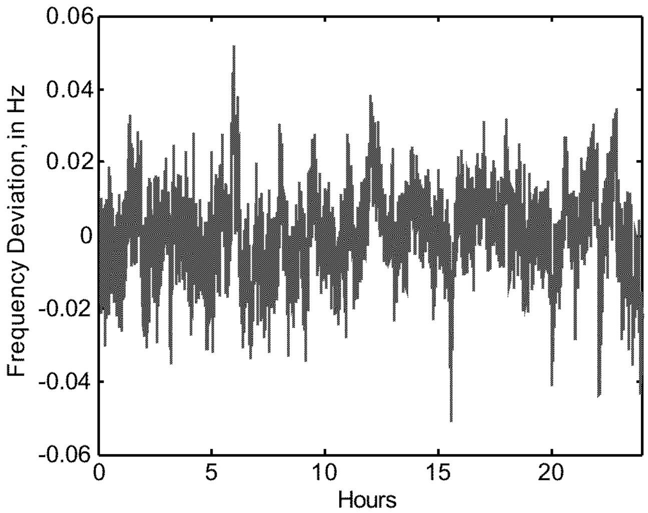


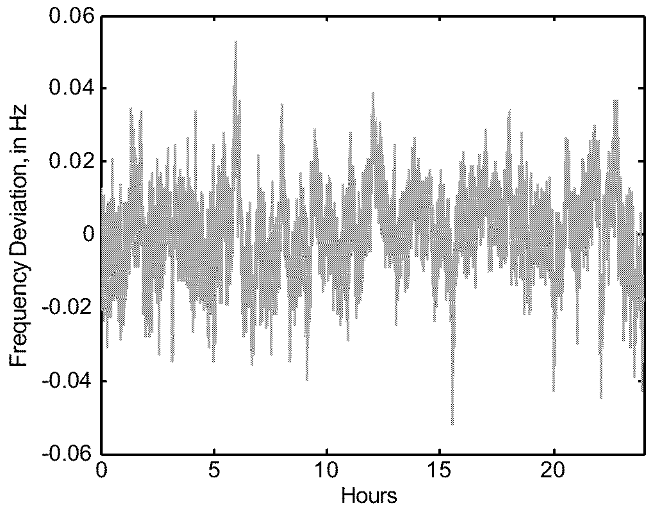


SB_GT&S_0130119

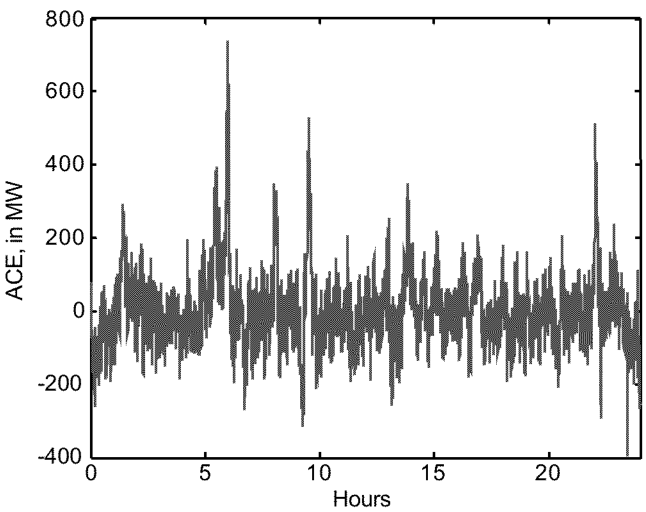
B.4 Monday July 7, 2008

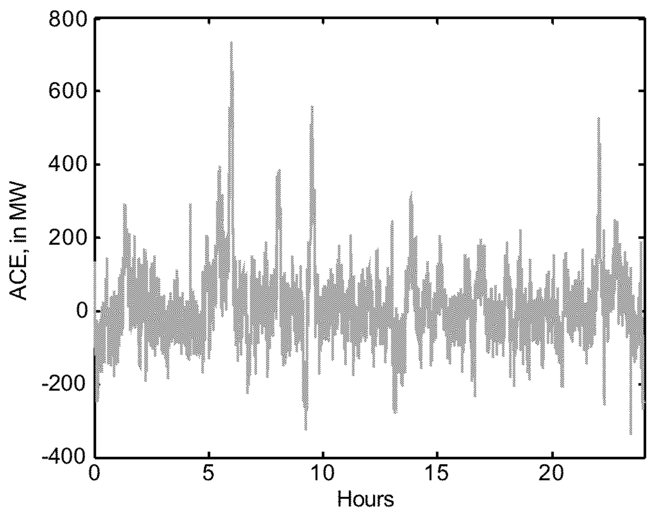
B.4.1 Frequency Deviation





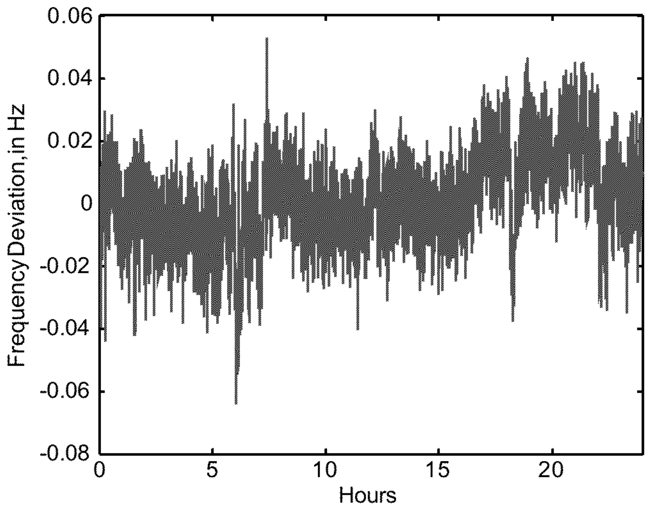
B.4.2 Area Control Error

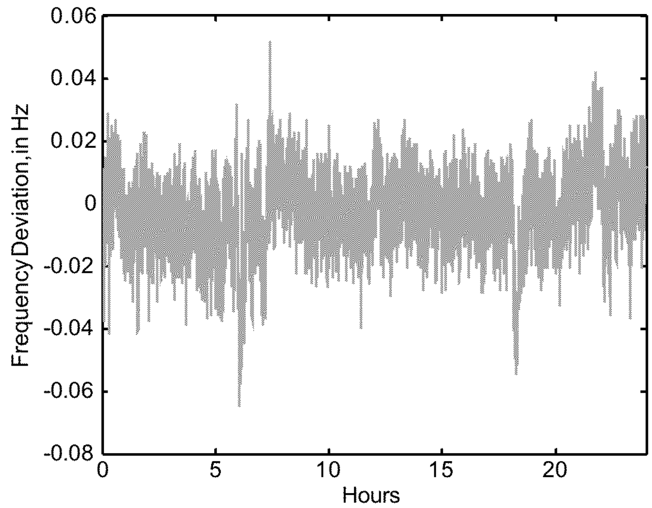




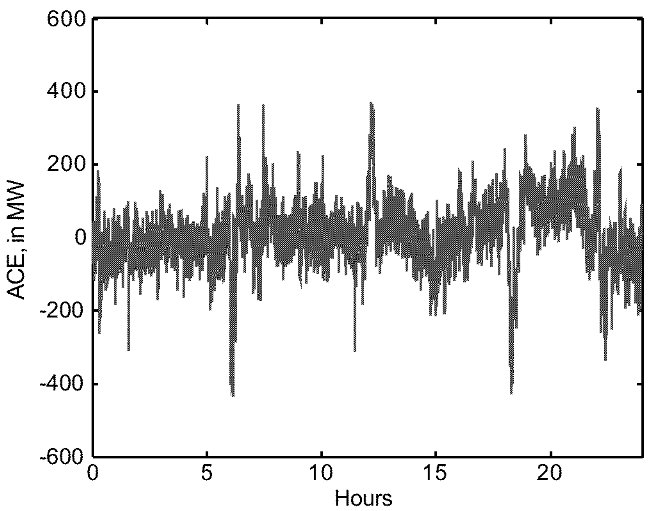
B.5 Monday October 20, 2008

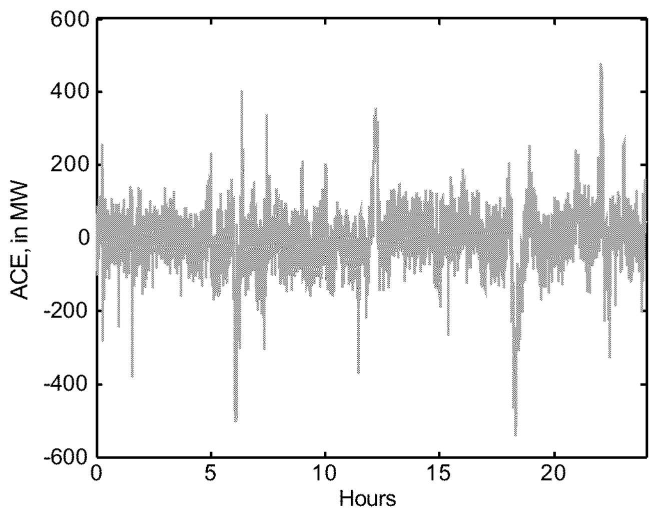
B.5.1 Frequency Deviation





B.5.2 Area Control Error



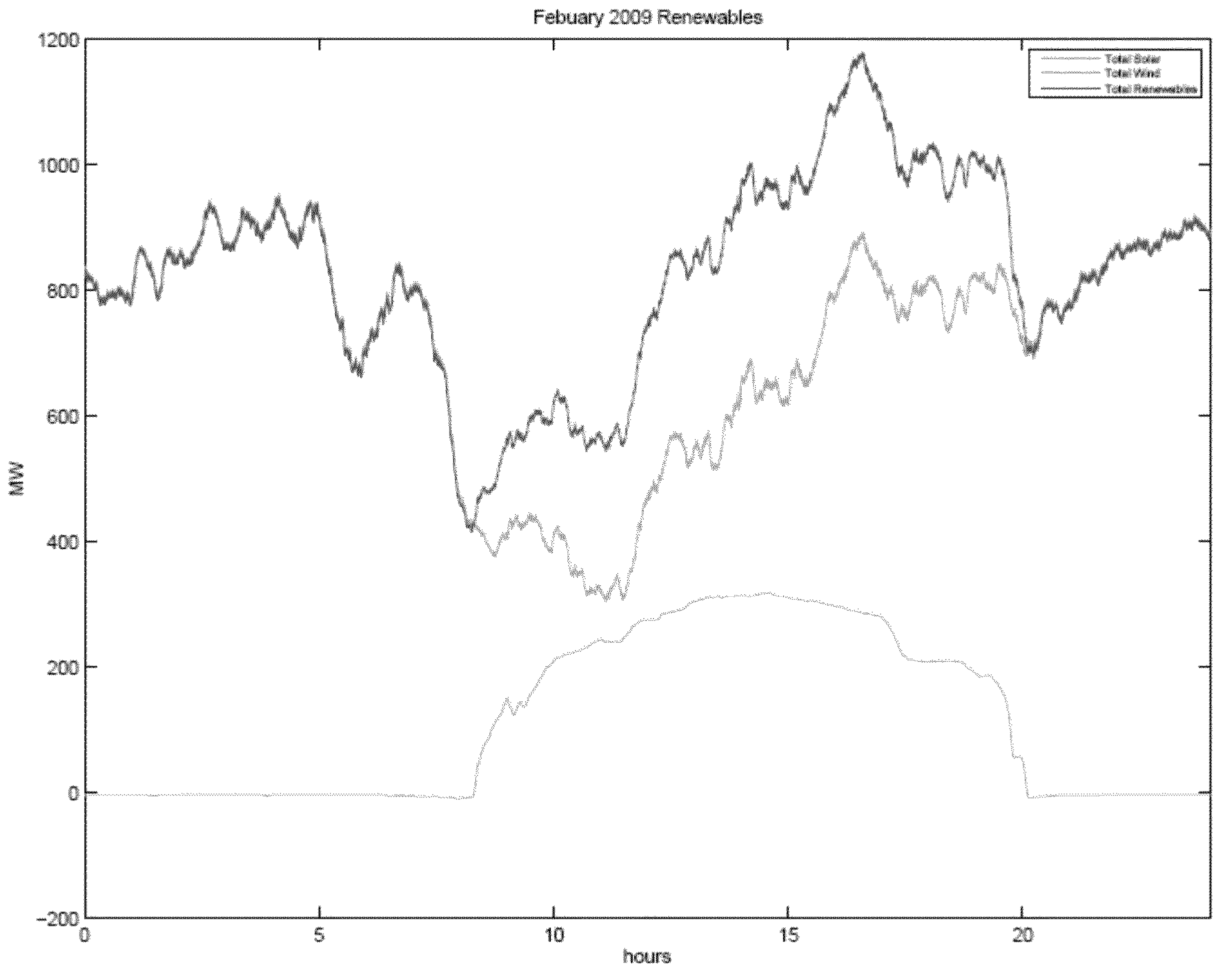


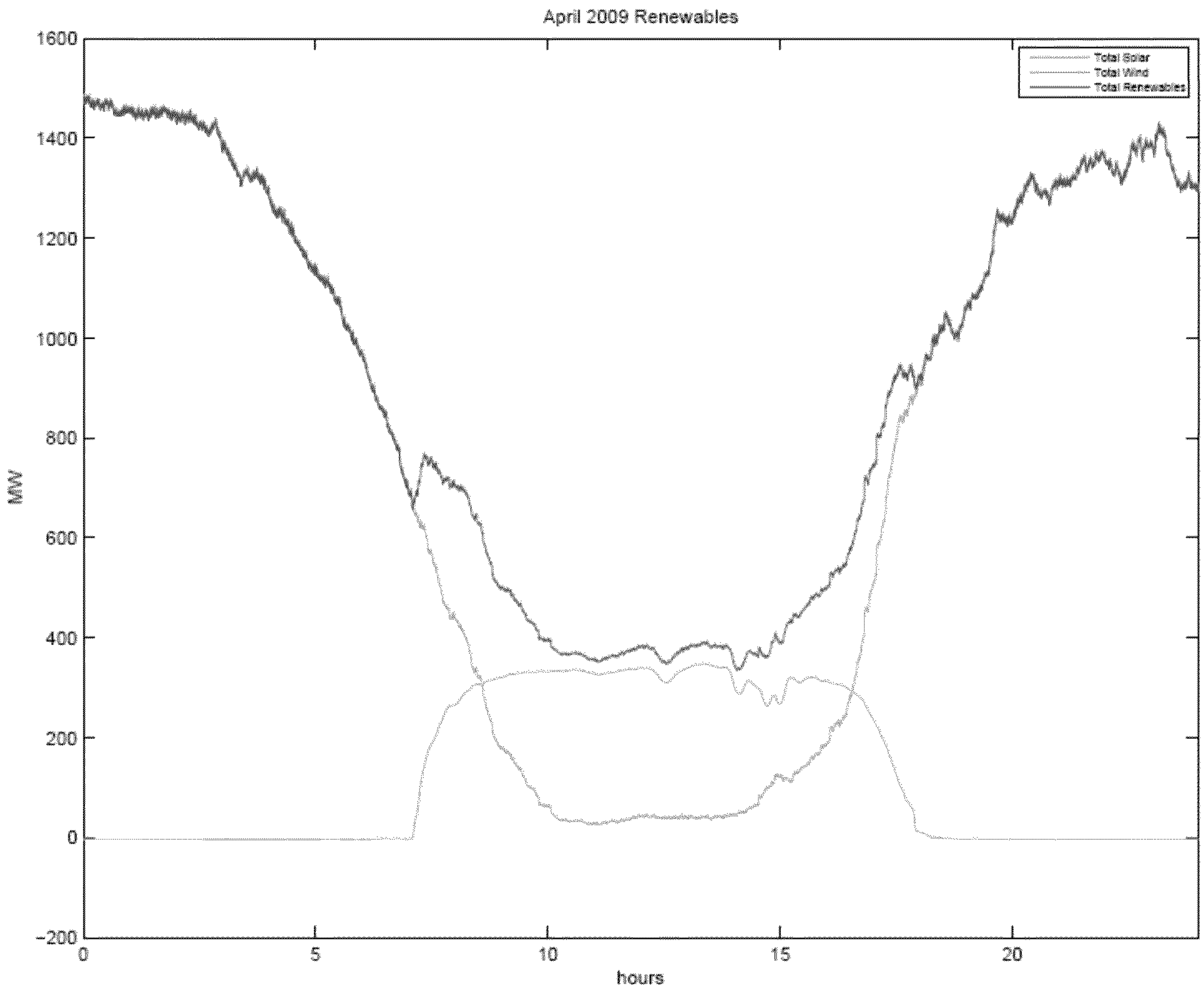
Appendix C: Base Day Characteristics

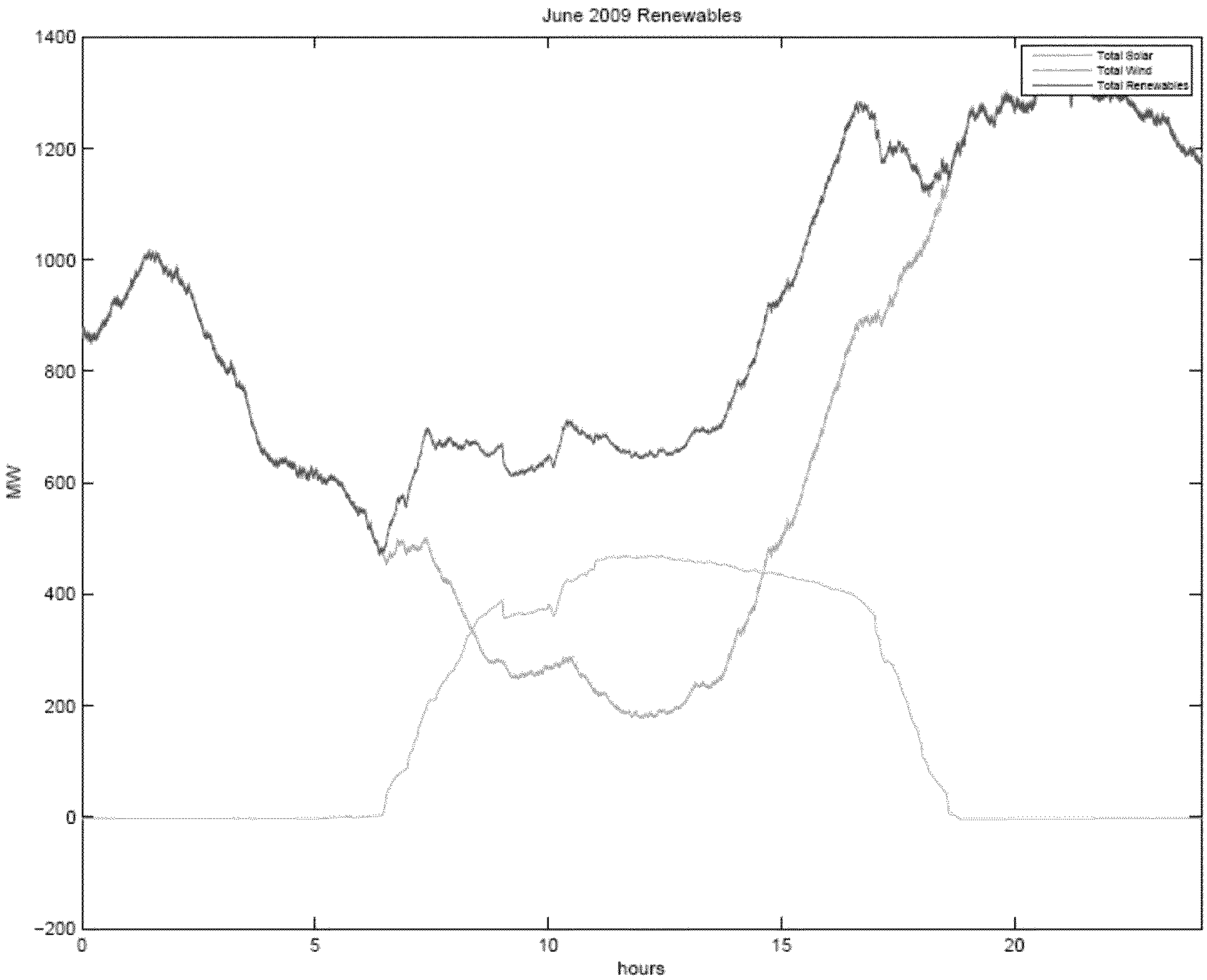
This appendix contains base day characteristics used as inputs to the model. Characteristics include daily load, renewable production, and dispatched generation by type.

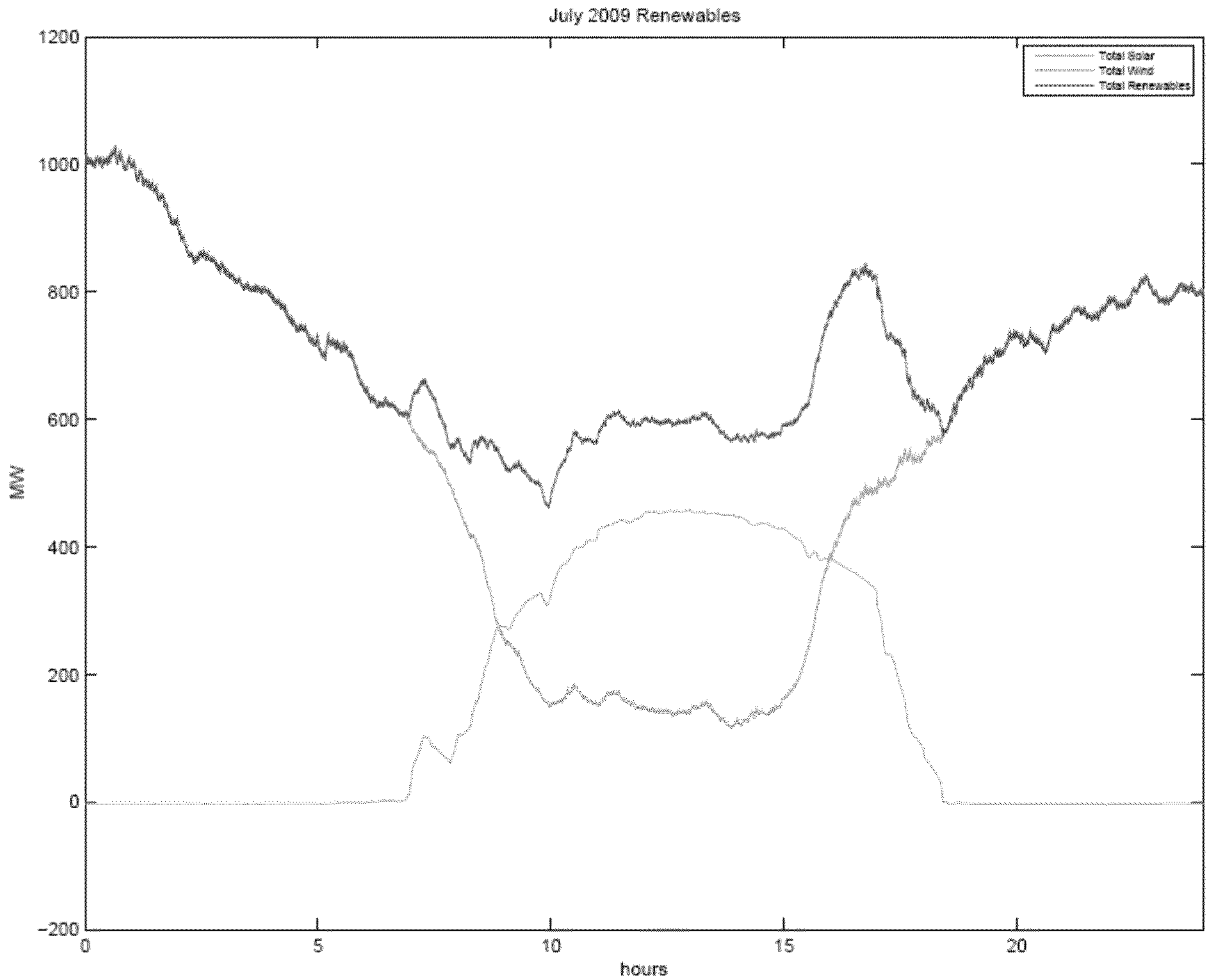
C.1 Renewable Production

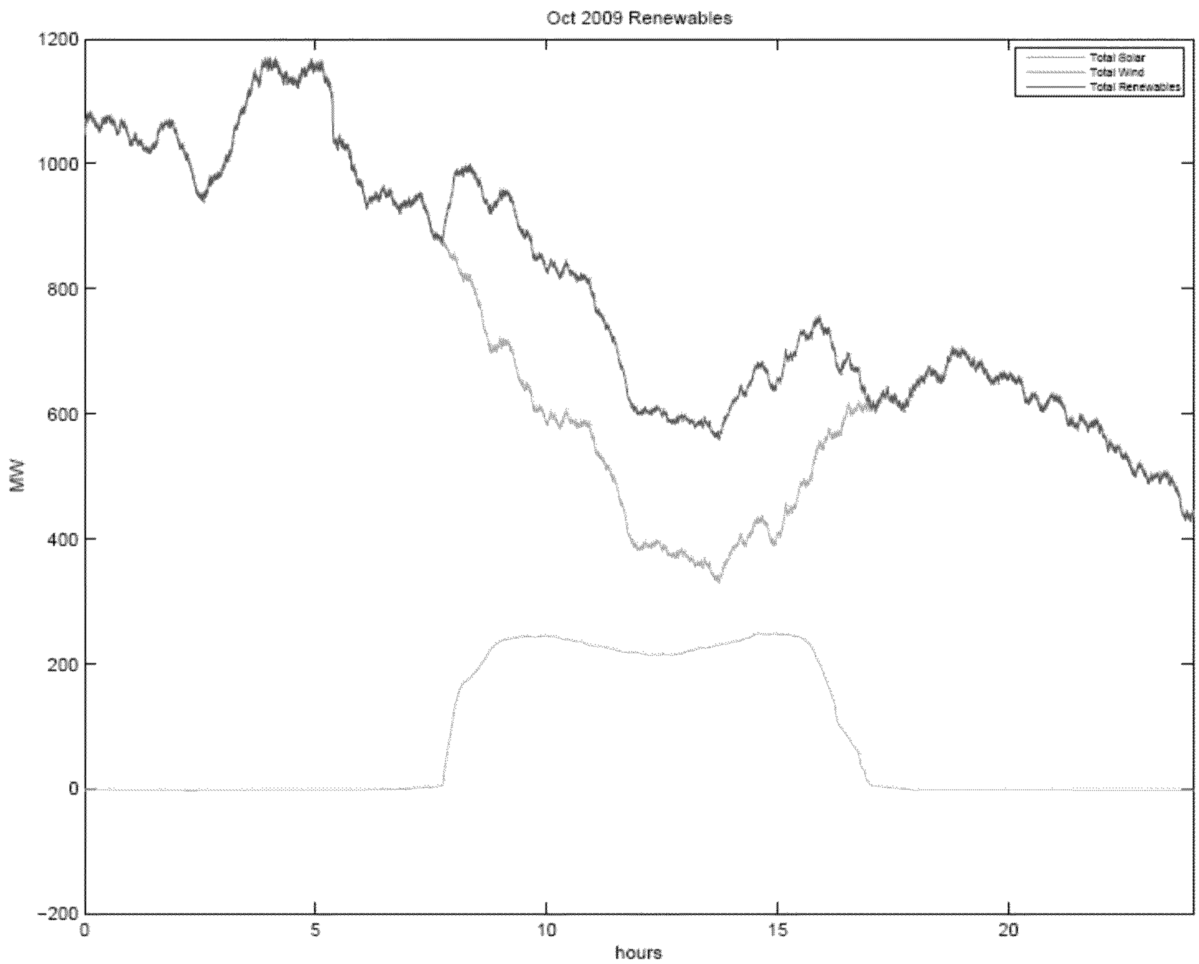
C.1.1 Base Cases




April 2009 Renewables
Total Solar
Total Wind
Total Renewables
MW
hours
1600
1400
1200
1000
800
600
400
200
0
-200
0
5
10
15
20


June 2009 Renewables
Total Solar
Total Wind
Total Renewables
1400
1200
1000
800
600
400
200
0
-200
MW
0
5
10
15
20
hours

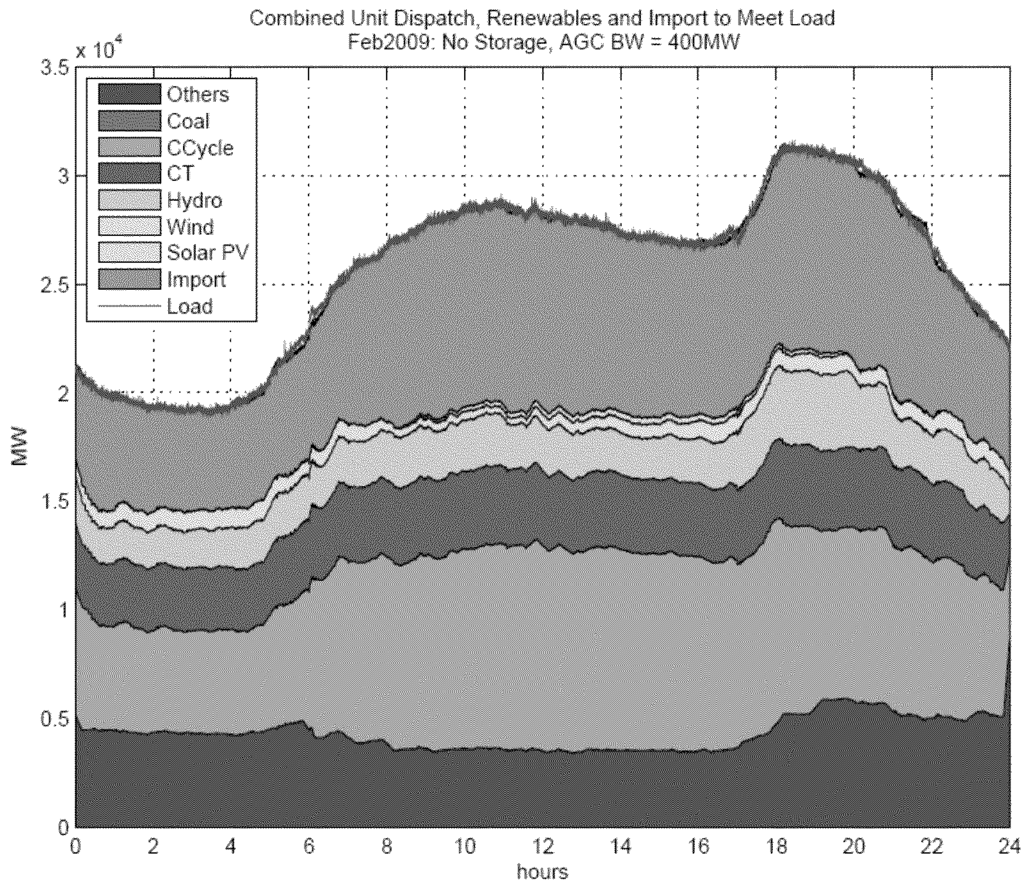

July 2009 Renewables
Total Solar
Total Wind
Total Renewables
MW
hours
1200
1000
800
600
400
200
0
−200
0
5
10
15
20

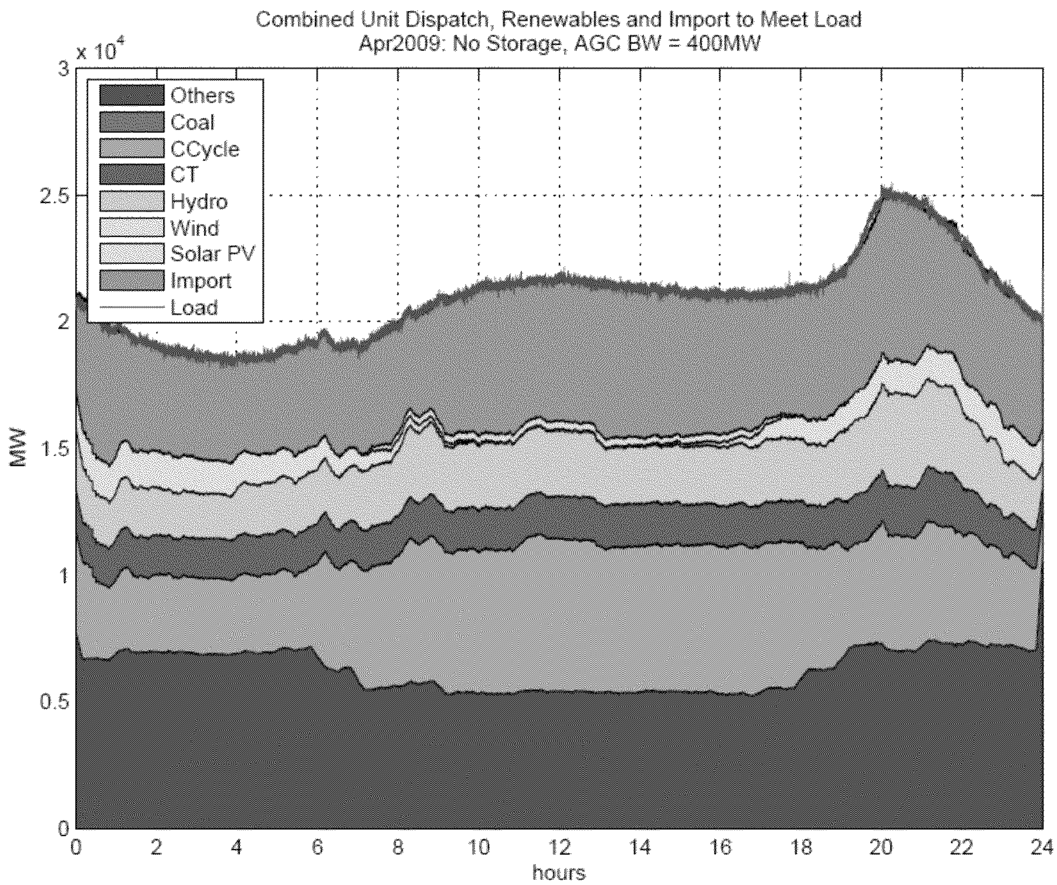


Oct 2009 Renewables
Total Solar
Total Wind
Total Renewables
1200
1000
800
600
400
200
0
−200
MW
0
5
10
15
20
hours

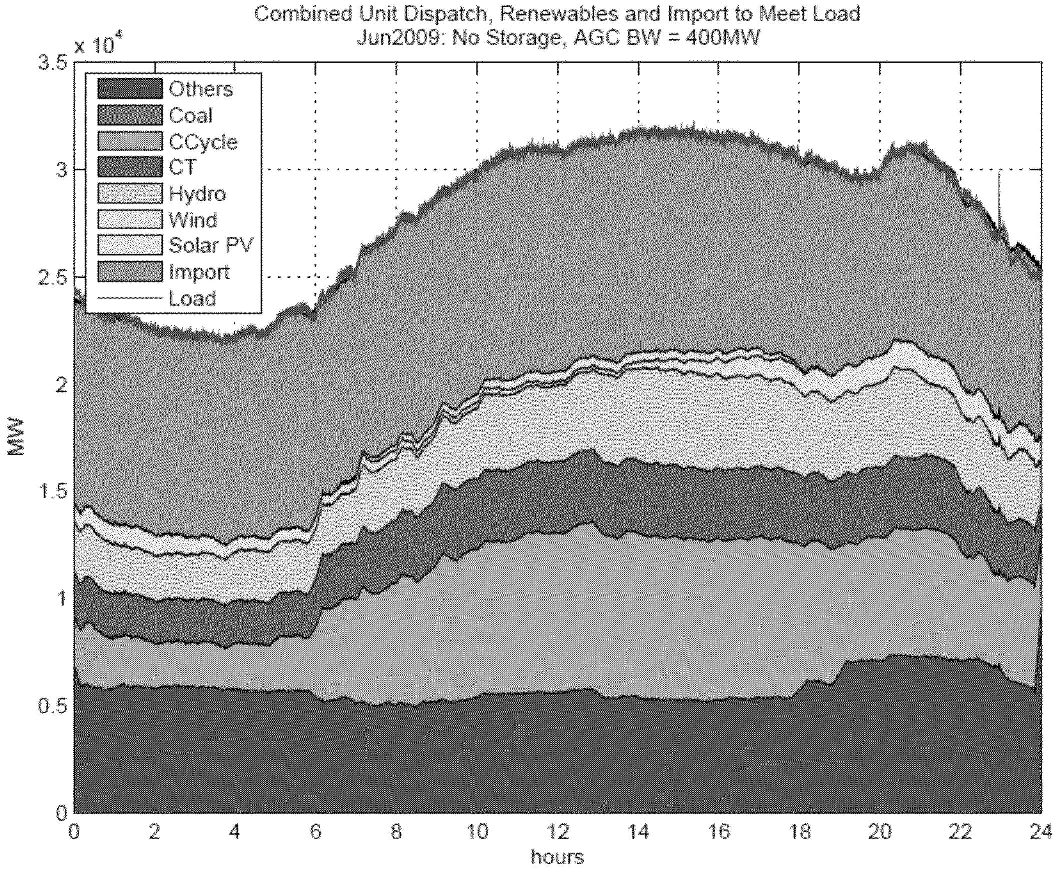
C.1 Total Dispatch

C.1.1 Base Cases

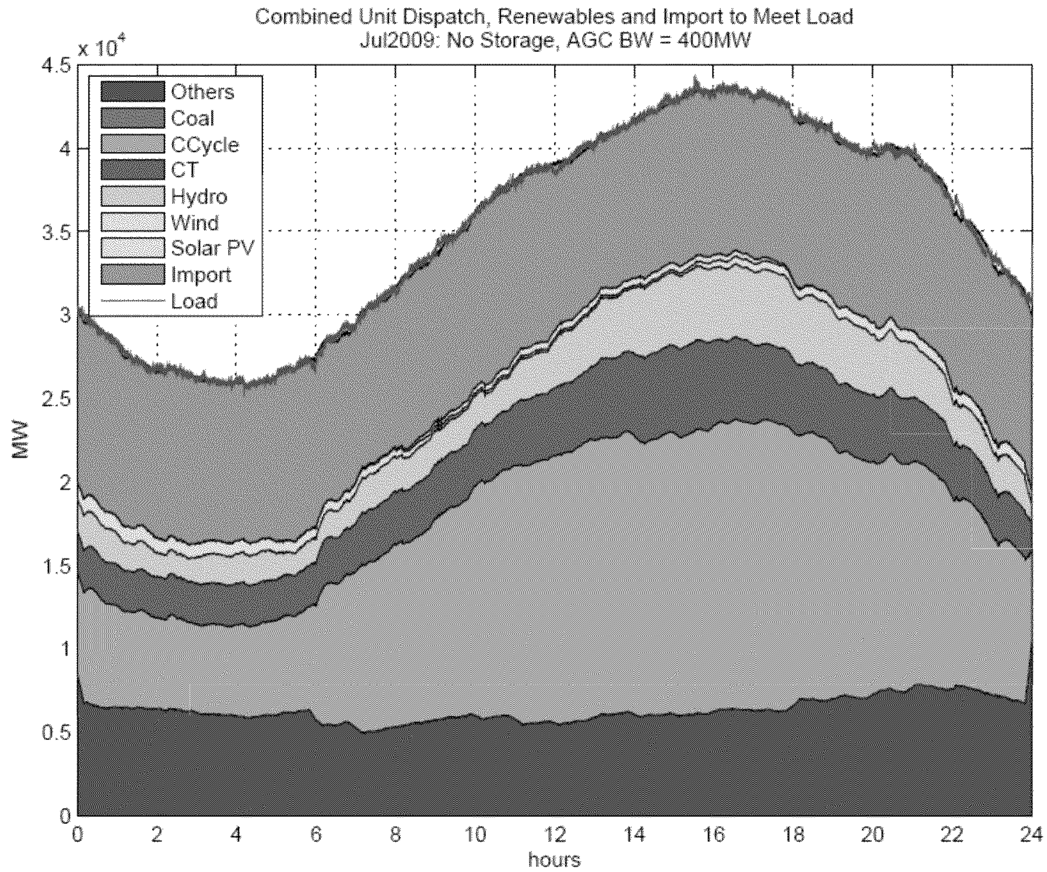




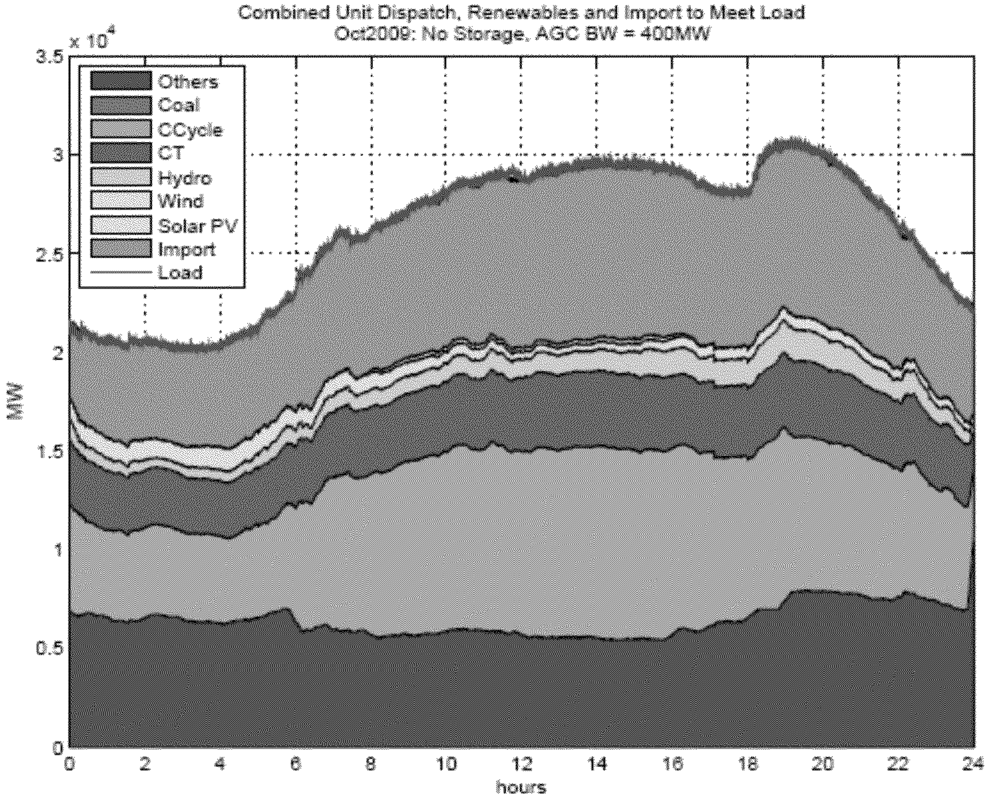
SB_GT&S_0130129



Combined Unit Dispatch, Renewables and Import to Meet Load
Jun2009: No Storage, AGC BW = 400MW
x 10^4
3.5
3
2.5
2
1.5
1
0.5
0
MW
Others
Coal
CCycle
CT
Hydro
Wind
Solar PV
Import
Load
0
2
4
6
8
10
12
14
16
18
20
22
24
hours



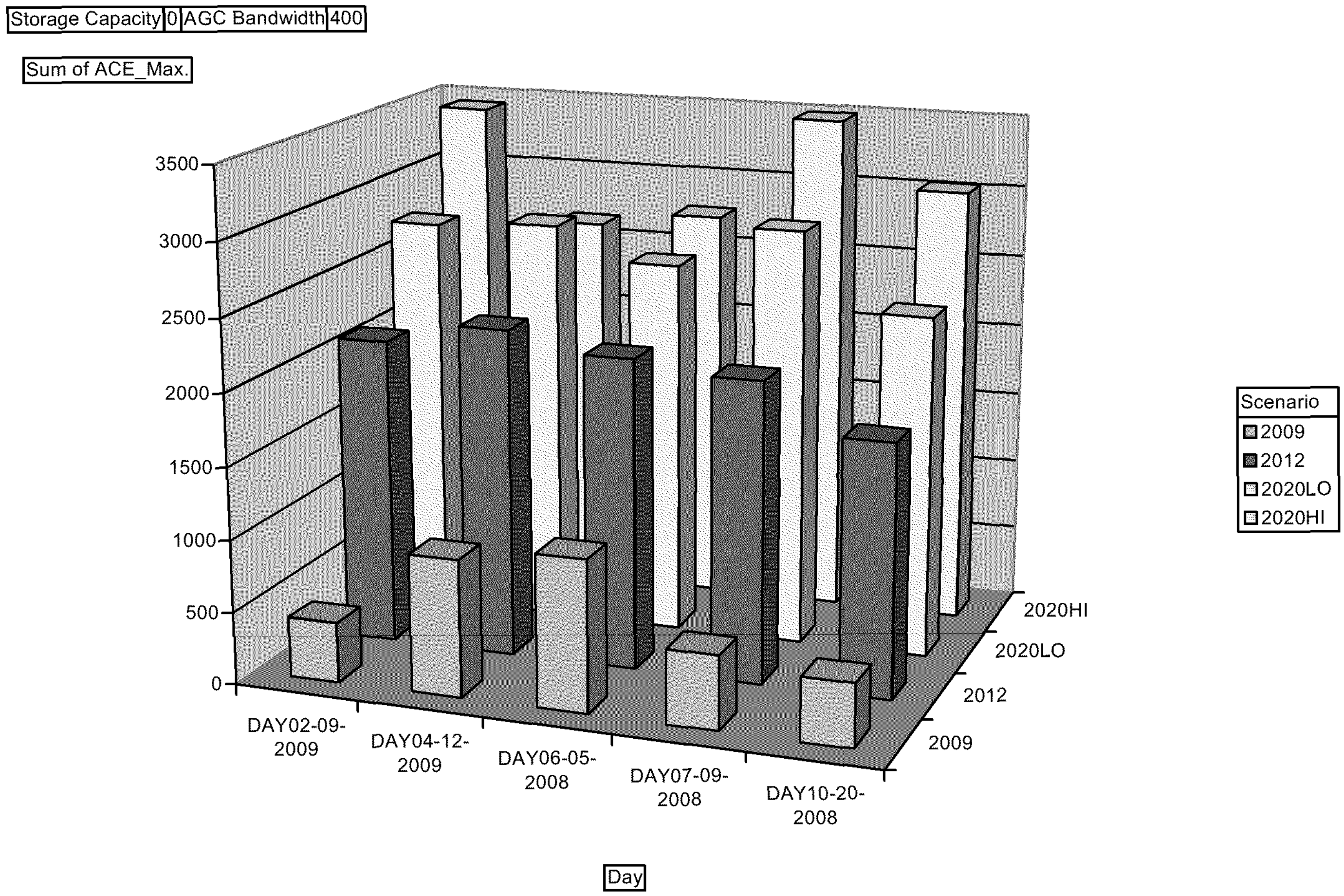
Combined Unit Dispatch, Renewables and Import to Meet Load
Jul2009: No Storage, AGC BW = 400MW
x 10^4
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
MW
Others
Coal
CCycle
CT
Hydro
Wind
Solar PV
Import
Load
0
2
4
6
8
10
12
14
16
18
20
22
24
hours


Combined Unit Dispatch, Renewables and Import to Meet Load
Oct2009: No Storage, AGC BW = 400MW
x 10^4
3.5
3
2.5
2
1.5
1
0.5
0
MW
Others
Coal
CCycle
CT
Hydro
Wind
Solar PV
Import
Load
0
2
4
6
8
10
12
14
16
18
20
22
24
hours

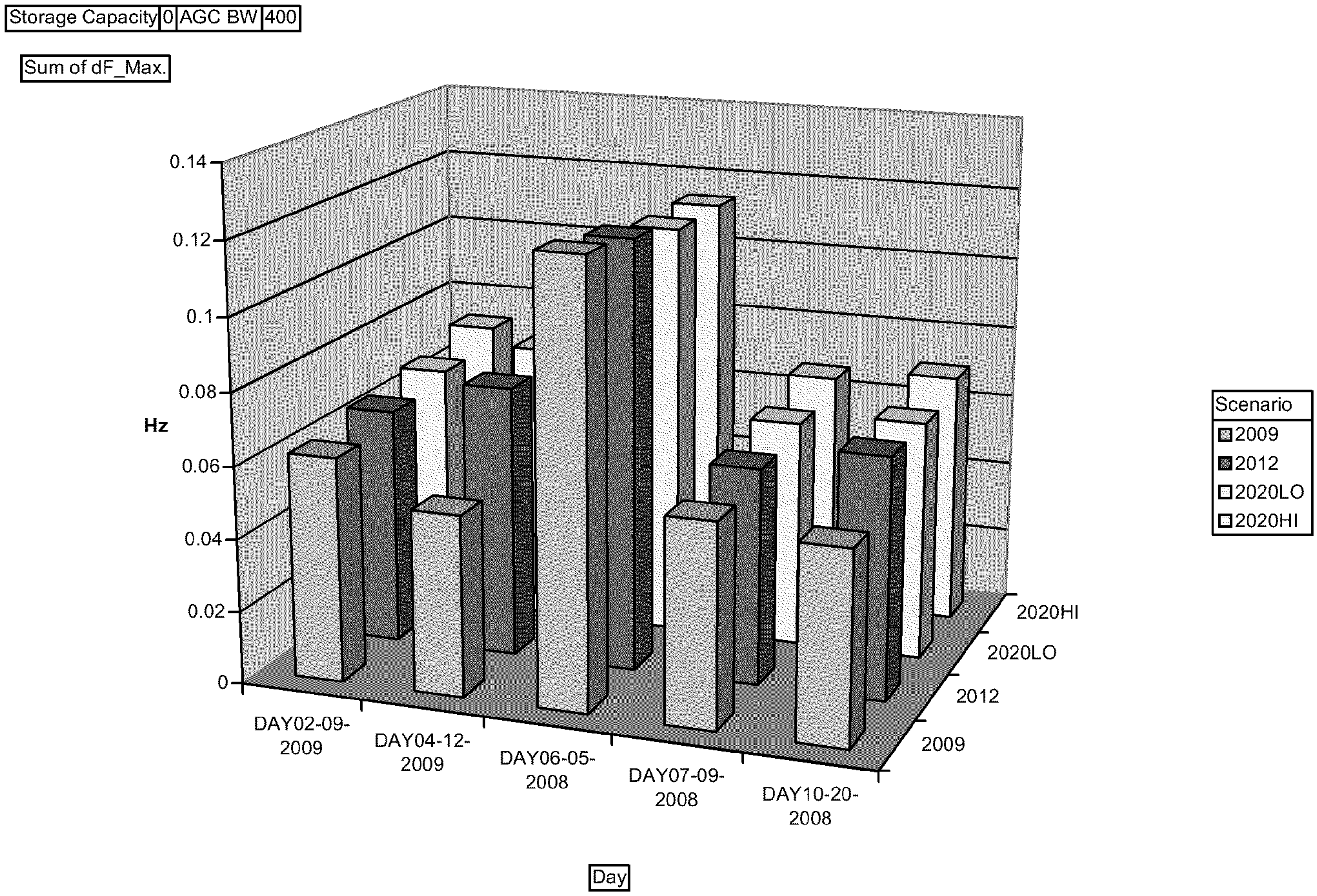
Appendix D: Results without Storage or Increased Regulation

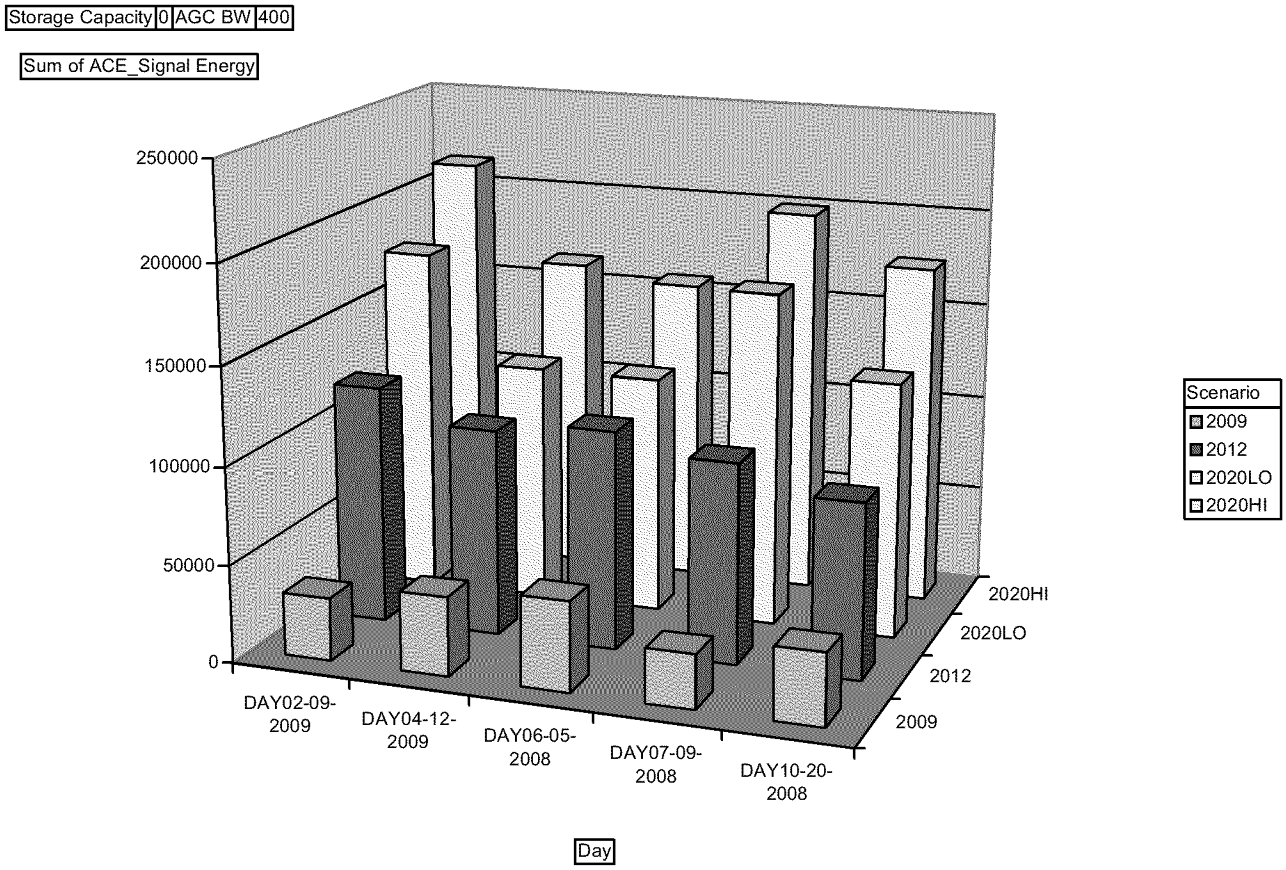
This appendix contains results for system metrics across all scenarios. Metrics include maximum ACE, maximum frequency deviation, and CPS1.

D.1 Summary Results

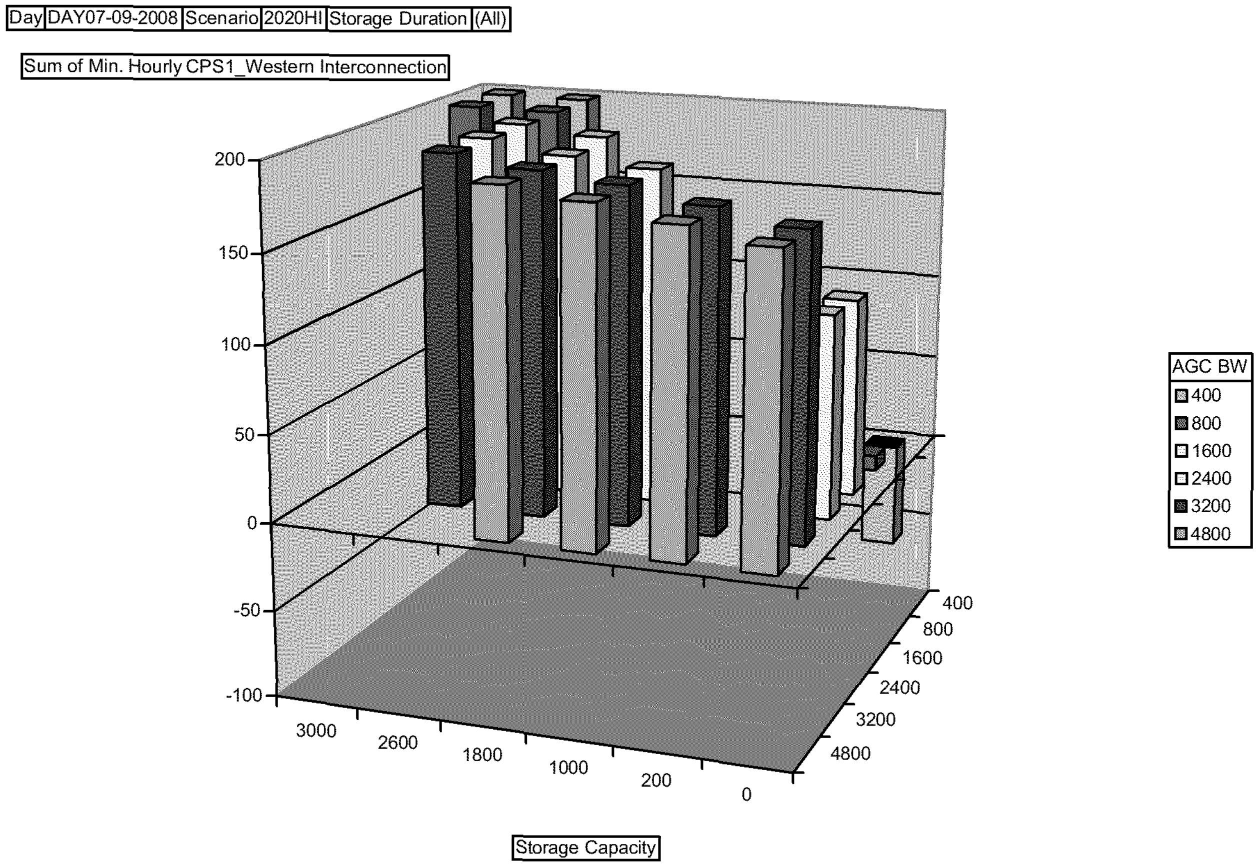


SB_GT&S_0130135


Storage Capacity 0 AGC BW 400
Sum of dF_Max.
Hz
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
DAY02-09-2009
DAY04-12-2009
DAY06-05-2008
DAY07-09-2008
DAY10-20-2008
2020HI
2020LO
2012
2009
Day
Scenario
2009
2012
2020LO
2020HI



SB_GT&S_0130137


Day DAY07-09-2008 Scenario 2020HI Storage Duration (All)
Sum of Min. Hourly CPS1_Western Interconnection
200
150
100
50
0
-50
-100
3000
2600
1800
1000
200
0
400
800
1600
2400
3200
4800
Storage Capacity
AGC BW
400
800
1600
2400
3200
4800