UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources	**)** **)**	**Docket No. RM10-11-000**

COMMENTS OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
TO NOTICE OF PROPOSED RULEMAKING

The California Independent System Operator Corporation hereby submits its comments in response to the Federal Energy Regulatory Commission's proposed reforms of the *pro forma* Open Access Transmission Tariff (OATT) contained in the notice of proposed rulemaking (NOPR) issued in the above captioned docket. The ISO supports the Commission's efforts to remove barriers to the integration of variable energy resources and to do so in a manner that aids in the reliable operation of the interconnected grid and recognizes the presence of such resources varies throughout the various regions of the country. The ISO faces increasing operational and reliability challenges resulting from thousands of megawatts of wind and solar facilities seeking to interconnect to to and/or be transmitted on the ISO's transmission grid over the next several years in response to California's renewable portfolio requirements.[1] The ISO is closely evaluating needed changes to its market rules, transmission planning process, and generator interconnection policies to facilitate the efficient and reliable integration of such resources within the ISO balancing authority area.[2] The ISO offers these comments to assist the Commission

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[1] California currently has a 33 percent renewable energy portfolio by 2020 standard, as reflected in a Governor's Executive Order. *See* http://gov.ca.gov/executive-order/11072/.

[2] As the Commission recognizes in paragraph 16 of its notice of proposed rulemaking, the ISO conducted a stakeholder process last year and proposed amendments to its large generator interconnection agreement to establish interconnection requirements for wind and solar photovoltaic resources. (*Cal. Indep. Sys. Operator Corp.*, 131 FERC ¶ 61,087 (2010), *rehearing pending* in Docket ER10-1706.) The technical requirements proposed by ISO for reactive power, automatic voltage control, and power management capabilities will

in fashioning a final rule that provides just, reasonable, workable, and operationally sound regulations that will assist the ISO in its efforts to support the reliable integration of variable energy resources on its grid in order to enable achievement of California's renewable portfolio requirements.

I. Executive Summary

The Commission proposes to eliminate and prevent operational procedures that have the *de facto* effect of unduly discriminating against variable energy resources as their presence on the transmission grid increases. These reforms include proposals to allow for intra-hour transmission, scheduling, power production forecasts, and recovery of charges for generator regulation service. The ISO generally supports and commends the Commission's efforts and proposes slight modifications for the Commission's consideration in fashioning the final rule that will enable the ISO to continue to work with its stakeholders in making appropriate market rule changes that can effectively address the specific market and operational issues posed by the increasing presence of variable energy resources in the ISO balancing authority area.

The ISO supports the Commission's direction to require greater intra-hour transmission scheduling flexibility. There are multiple ways in which the ISO's market based transmission service already provides intra-hour transmission service flexibility. Internally, under the ISO's nodal market, market participants are not constrained by hourly transmission service reservations. The ISO's market provides market participants the ability to reconcile hourly day-ahead schedules through the ISO's five-minute energy imbalance market, thereby enabling internal resources to

significantly enhance the ISO's ability to meet system reliability challenges without creating an undue burden on variable energy resources.

manage intra-hour changes in their output. The ISO's market also affords import resources with the same degree of intra-hour flexibility through the ISO's dynamic scheduling option for imports. The ISO is considering specific rule changes for dynamic schedules of imports to allow variable energy resources to utilize the dynamic scheduling functionality more effectively and to allow for dynamic exports. In addition, the ISO is coordinating with its neighboring balancing authorities to ensure sufficient intra-hour flexibility exists to facilitate the seamless transfer of variable energy in a reliable and efficient manner. For example, the ISO and Bonneville Power Administration (BPA) have already established a pilot program though which BPA will permit transmission reservations and intra-hour scheduling changes on a half-hour basis. The ISO asks that the Commission's final rule recognize that in certain areas transitional measures such as this pilot program may be necessary to ensure the adoption of more flexible transmission reservation rules.

The ISO also supports the Commission's proposal to require that variable energy resources provide meteorological data. The ISO's tariff (Appendix Q) already requires that all eligible intermittent resources (wind and solar) provide the same meteorological data the Commission is proposing to require through a generator interconnection agreement. Consistent with the ISO's tariff, the ISO recommends that the Commission extend its proposed requirement to resources below 20 MW in size and ensure the uniform availability of such data by disallowing grandfathering exceptions to such requirements. Setting the threshold at a high level may inhibit transmission providers from obtaining needed meteorological data from smaller size resources that individually do not make the threshold but in the aggregate resulting in a lack of visibility that may impact system reliability.

Finally, the ISO tariff provides a regulation product that captures both load and generator variability and does not pose any of the barriers to entry for variable energy resources that the Commission seeks to eliminate through the NOPR. However, the ISO recognizes the need to reevaluate cost allocation for regulation requirements, including the consideration of a volumetric rate, in the anticipation of an influx of additional variable energy resources. This increase in the presence variable energy resources may result in greater variability caused by generation as opposed to load as was the case when the ISO developed the existing ancillary services products in its market. As a result, the ISO is extending its current renewable integration market and product review stakeholder process to address these issues specifically. The final rule should retain the flexibility for parties to propose such possible market enhancements and propose cost allocation schemes that best address their market needs and realities.

The ISO believes the Commission's proposed reforms will provide greater system flexibility and help integrate variable energy resources into the transmission system. The Commission, however, must continue to balance the need for reforms with the need for transmission operators to have the latitude necessary to address the unique integration issues that exist in the various regions of the country. Effective and reliable integration of variable energy resources requires that the available "tools" be flexible enough to address the unique circumstances, resource mix, and particular operational concerns/problems existing in each region.

II. Background

In its NOPR, the Commission states that in response to the notice of inquiry issued last year, parties commented that the presence of variable energy resources is not uniform throughout the country and that there are significant industry efforts being undertaken in numerous regions that potentially could address issues pertaining to the integration of large concentrations of variable energy resources. Therefore, the NOPR proposes only a limited set of reforms to existing operational procedures that the Commission preliminarily finds to be necessary to eliminate unduly discriminatory practices that lead to unjust and unreasonable rates for transmission service.

More specifically, the Commission proposes to:

> (1) amend the *pro forma* OATT to require intra-hourly transmission scheduling;
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> (2) amend the *pro forma* Large Generator Interconnection Agreement to incorporate provisions requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting; and
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> (3) amend the *pro forma* OATT to add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service, in which public utility transmission providers will offer to provide regulation service for transmission customers using transmission service to deliver energy from a generator located within a public utility transmission provider's balancing authority area.

The Commission preliminary finds that the proposed rules will eliminate operational procedures that have the *de facto* effect of imposing an undue burden on variable energy resources. As the Commission notes, public utility transmission providers developed existing practices as well as the ancillary services used to manage system variability at a time when virtually all generation on the system could be scheduled with relative precision and only load exhibited significant degrees of within-hour variation. The Commission is not proposing to address the additional issues identified in its earlier notice of inquiry at this time. The NOPR recognizes that parties are actively developing solutions to address issues raised in the notice of inquiry.

The ISO submitted extensive comments in response to the notice of inquiry. Since then, the ISO has conducted additional analysis as part of its efforts to integrate and operate the ISO balancing authority area reliably as the nature and characteristics of its fleet changes in order to meet California's renewable portfolio requirements.[3] In concert with state agencies and policy-makers, and California's electric power industry, the ISO is preparing for the substantial planning, operational, technological, and market changes required for the integration of anticipated higher levels of renewable resources. The ISO has also established a renewable resources integration program, with the objective to provide operational assessments, technology evaluation and standards, and other needed capabilities as variable energy resource integration expands into and begin to affect the ISO's core functions. Analysis of future renewable resource investment scenarios has become a central component of the ISO's transmission planning process. The ISO also commented that one of the its primary goals is to integrate these resources through their participation in the ISO's day-ahead and real-time markets, which the ISO utilizes to allocate transmission service, manage congestion, enable spot energy trading, and operate the ISO controlled grid.

Below the ISO comments on the three areas of reform proposed by the Commission and offers, as appropriate, additional findings from its recently completed *20 Percent RPS Study* in support of the Commission's efforts.

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[3] CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION. INTEGRATION OF RENEWABLE RESOURCES: OPERATIONAL REQUIREMENTS AND FLEET CAPABILITY AT 20 % RPS. August 31, 2010. [available at: http://www.caiso.com/2804/2804d036401f0.pdf]. (hereafter referred to as the "*20 Percent RPS Study*"] [provided in Attachment A].

III. ISO Comments

A. Intra-Hourly Scheduling

The ISO supports the Commission's efforts to promote greater flexibility for transmission reservations in the *pro forma* OATT. In its NOPR, the Commission preliminarily finds that hourly transmission scheduling protocols and the default scheduling time periods required by the *pro forma* OATT are no longer just and reasonable and may be unduly discriminatory. Accordingly, the Commission proposes to amend sections 13.8 and 14.6 of the *pro forma* OATT to provide transmission customers the option to schedule transmission service on an intra-hour basis, at intervals of fifteen minutes. The Commission does not propose to eliminate the hourly transmission service reservations option provided in the *pro forma* OATT but instead proposes to require that all transmission providers offer a fifteen minute transmission scheduling option. The Commission's goal is to address purported discrimination perpetuated by the practice of requiring resources to match hourly transmission schedules in circumstances where supply resource variability increases substantially as a result of the presence of variable energy resources.[4] The Commission notes that this issue is particularly evident in non-market environments where transmission providers rely on the procurement of ancillary services on an hourly basis to balance the hourly schedules under rate schedules.[5]

The ISO agrees with the Commission's finding that practices requiring resources to match hourly transmission schedules creates inefficient and burdensome operational requirements, which are exacerbated in an environment with greater output from variable energy resources. In the recent *20 Percent RPS*

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[4] *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,149 at PP 38-39 (2010) ("VERs NOPR").

[5] VERs NOPR at P 39.

Study, the ISO determined that rigidity in energy schedules will undoubtedly inhibit the ISO's ability to manage increased variability.[6] While, as discussed further below, the ISO market does not restrict participants to hourly transmission service, this scheduling rigidity manifests itself in the ISO's market through the hourly self-schedules that the ISO cannot economically manage.[7]

1. The ISO's Single Daily Transmission Service and Energy Market Model Provides Multiple Opportunities for Providing Greater Scheduling Flexibility

The ISO itself does not operate pursuant to a *pro forma* OATT and, as the Commission has previously recognized, the ISO's market paradigm does not involve reservations of transmission service.[8] Under the ISO tariff, the ISO does not require hourly reservations for transmission service within the ISO balancing authority area, but instead operates a combined market for energy and ancillary services, through which the ISO is able to provide intra-hour flexibility for resources using the ISO controlled grid to serve their load or market their generation. Scheduling coordinators obtain access to the ISO controlled grid to serve load in or outside of

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6 *See 20 Percent RPS Study* at pp. *vii-viii*.

7 If provided with more economic bids, the ISO market optimization can achieve an efficient economic dispatch of those resources according to system and local needs rather than by cutting those self-schedules or by relying on out-of-market actions such as exceptional dispatch to manage congestion. While there may be legitimate reasons and even contractual obligations that require parties to submit self-schedules, as discussed in the *20 Percent RPS Study*, the ability to operate the system efficiently with the anticipated 20 percent renewable portfolio requirements requires sufficient market participation by both non-variable and variable resources. The *20 Percent RPS Study* recommended that the ISO should evaluate means to obtain additional operational flexibility from wind and solar resources. The simulations demonstrated especially the need for additional dispatchable capacity in the morning hours under certain conditions. The study authors recommended that the ISO explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch.

8 *See e.g., Cal. Ind. Sys. Operator Corp.*, 123 FERC ¶ 61,180 at PP 7-9, 18 (2008) (order accepting the ISO's filing in compliance with Order No. 890). In contrast to the *pro forma* OATT, the ISO does not offer transmission service under a physical rights transmission service model under which a public utility provides network and firm and non-firm point-to-point transmission service. Rather, the ISO offers a single "daily" transmission service that is available on a non-discriminatory basis to all eligible customers on a day- to-day basis. With the exception of certain transactions scheduled pursuant to grandfathered agreements, all energy transmitted under the ISO is treated as a "new firm use" and is scheduled on a day-to-day basis. Under the ISO's service model all users of the ISO controlled grid schedule their use each day and cannot reserve available transmission capacity beyond the day-ahead timeframe. This model ensures optimal flexibility and nondiscriminatory use of available capacity

the ISO balancing authority area through the applicable transmission access charge for internal load, or wheeling access charge for wheeling through or wheeling out service for external load. All resources are able to schedule in one-hour blocks in the day-ahead market. Once the operating day begins, the real-time market serves to adjust day-ahead schedules to account for imbalances due to forecast error, changes in system conditions, actual intra-hourly load and renewable energy production, and other factors that may result in deviations from scheduled amounts. Day-ahead schedules are settled on an hourly basis, and imbalances from such schedules, or lack thereof, for scheduling coordinators that do not submit day-ahead bids or schedules are resolved in the hour-ahead scheduling process and real-time market.

The hour-ahead process provides for settlement of non-dynamic intertie schedules for energy or ancillary services from external resources on an hourly basis. Imbalances for internal resources and dynamically scheduled intertie resources are cleared on a five minute basis and settled on a ten minute basis for energy, and are cleared and settled on a fifteen minute basis for ancillary services. This structure provides significant flexibility for dealing with intra-hour variability by providing the opportunity for both economic and non-economic adjustments.

The ISO also manages ancillary services through this process. The ISO attempts to procure all of its ancillary services needs in the day-ahead market on an hourly basis. In the real-time, the ISO accounts for intra-hour variability through its fifteen minute procurement process conducted in the real-time unit commitment process. The real-time unit commitment process re-optimizes ancillary services procurement taking into consideration changed system conditions on a fifteen minute increment basis. The ISO continues to procure ancillary services from the interties on an hourly basis for non-dynamic services, which are also scheduled and cleared on an hourly basis. Under this construct, the ISO and market participants can take advantage of the shorter intervals and more accurate intra-hour schedules.

In developing its nodal market, the ISO adopted the hour-ahead scheduling process for the purposes of clearing intertie schedules, which as a result of hourly transmission reservation requirements of the ISO's neighboring balancing authority areas, are established and processed prior to the operating hour. The hourly imports or exports are settled as hourly imbalances from day-ahead schedules and are static for the applicable hour. Bids for the real-time imbalance energy markets both at its interties and for internal locations are accepted seventy-five minutes prior to the applicable hour. Bids for the five-minute real-time imbalance energy market are submitted at the same time for the applicable hour. While bids and self-schedules are established hourly, the real-time market optimizes and clears submitted bids every five minutes allowing the ISO to issue feasible dispatches to resources in the real-time. Imbalance energy from resources that deviate from schedules or dispatches is settled at real-time market prices. Currently, the ISO does not apply any uninstructed deviation penalties for such deviations.

2. Additional Scheduling Flexibility is Possible for External Variable Energy Resources under the ISO's Dynamic Transfers Paradigm

The same transmission scheduling flexibility afforded to internal resources under the ISO transmission service model is afforded to imports at the interties if the import resource is dynamically scheduled into the ISO balancing authority area. Dynamically scheduled resources are able to deviate from any hourly schedule either as a result of an ISO dispatch or on its own initiative, despite the hourly reservation. For dynamically scheduled imports into the ISO balancing authority area, the transmission reservation consists of the ISO awarded schedule and dispatch.

Over the past two years, independent power project developers of external conventional and variable energy resources expressed interest to participate in various ISO markets and renewable energy programs, including the ISO's participating intermittent resource program. ISO load serving entities expressed a concern that dynamic transfers are essential for incorporating out-of-ISO balancing authority area variable energy resources into their portfolios, because in some cases they have already contracted outside the ISO balancing authority area to meet their renewable portfolio requirements.

As variable energy resources begin to increase their utilization of the dynamic transfer feature, parties have raised concerns regarding the ISO's ability to maintain full transmission utilization, while recognizing the variability of intermittent resources' output. A fundamental difference between scheduling generation within the ISO balancing authority area and scheduling dynamic transfers is that dynamic transfers must cross interties. These interties are subject to specific scheduling constraints that are not necessarily the same as constraints on the thermal capacity of the transmission lines and are not determined solely by conditions within the ISO balancing authority area. Intertie schedules are also subject to certain NERC and WECC standards that do not apply to schedules within the ISO balancing authority area.[9] For example, NERC electronic tags (e-tags) for dynamic scheduling contain capacity values for both expected delivery and maximum delivery.

[9] Under Section 6.1 of Appendix X (Dynamic Scheduling Protocol) of the ISO tariff, "a firm (or non-interruptible for that hour) matching transmission service must be reserved across the entire Dynamic Schedule transmission path external to the CAISO Balancing Authority Area" for any hour for which energy and/or ancillary services (and associated energy) is scheduled dynamically to the ISO from an external resource, However, Section 6.11 of Appendix X, further states that "In Real-Time the Dynamic Schedule may not exceed the maximum value established by the sum of the Day-Ahead Market and HASP/RTM accepted Energy and Ancillary

Over the past year, the ISO has evaluated its current dynamic scheduling tariff rules to clarify tariff provisions for conventional resources, extend the existing use of dynamic scheduling for imports of conventional resources to include dynamic transfer of variable energy resources from other balancing authority areas as well as dynamic exports from the ISO balancing authority area, and incorporate pseudo-tie service in the ISO tariff.

Initially, stakeholders raised concerns regarding the ISO's ability to extend the dynamic scheduling functionality to variable energy resources and argued that extending this functionality to resources outside of the ISO balancing authority area or introducing dynamic exports would require the imposition of additional limitations at the interties due to transmission capacity limitations. In response, the ISO published a study (prepared by GE Energy) of the ISO's transfer capability for supporting dynamic transfers of variable energy resources, entitled "Final Report on Impact of Dynamic Schedules on Interfaces."[10] Based on this study, the ISO concluded that no additional limits (beyond the existing path limits for the California-Oregon Intertie and West of Colorado River interties that were studied) are required at this time on dynamically scheduled variable energy resources from the perspective of the ISO balancing authority area. The ISO will monitor its operating conditions as variable energy resources become more prevalent and may reevaluate this conclusion if conditions change. If questions arise concerning limitations on specific interties where there are specific proposals for dynamic transfers of variable

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Services Bids plus any response to the CAISO's Real-Time Dispatch Instructions. The composite value of the Dynamic Schedule derived from the Day-Ahead and HASP/RTM accepted Bids plus any Dispatch Instruction response represents not only the estimated Dynamic System Resource's Energy but also the transmission reservation on the associated CAISO Scheduling Point." Requiring dynamic transfers to be supported by firm transmission only for each operating hour avoids the need for long-term transmission contracts outside the ISO balancing authority area, which would further limit availability of transmission to get to the ISO boundary.

[10] This report is available at http://www.caiso.com/2aff/2aff9e9150530.pdf.

energy resources, the ISO will work with the affected neighboring balancing authority to examine the potential limitations on dynamic transfers.

An energy schedule or ancillary service award at an intertie automatically carries a transmission reservation in the existing ISO markets. Both must be confirmed using an e-tag. There is currently no ability to acquire transmission across an intertie into the ISO market separately from the energy and ancillary services schedules, for which the transmission reservation in the ISO market exactly equals the energy and ancillary services schedule. It would not be meaningful for a static energy schedule to reserve additional transmission capacity because a scheduling coordinator cannot increase the static energy schedule during the operating hour (except for the defined inter-hour ramping). The issue of establishing additional transmission reservations therefore arises only for dynamic transfers, which receive dispatches within the operating hour to follow the ISO's system conditions or a variable energy resource's availability.

Dynamic resources are modeled as internal generation and the ISO's market software manages dynamic schedules using only the value for expected delivery. This value represents the transmission reservation for purposes of the ISO market. However, if a dynamically scheduled intermittent resource were to schedule its average expected delivery and other interchange schedules were accepted up to the intertie's full capacity, the intermittent resource may be unable to deliver more than its initial expected energy schedule. Alternatively, external variable energy resources could over-schedule at the intertie in an attempt to ensure that sufficient capacity is available. In such situations the ISO's market systems could expect that it would receive more energy from the intermittent resources than such resources would actually be expected to produce, and may fail to commit sufficient dispatchable capacity to maintain the required energy balance. Excessive scheduling for the purpose of obtaining flexibility for intermittent deliveries could also result in unused transmission capacity that could have been used by other market participants. As the use of dynamic transfers grows, management of the interties becomes more important to ensure full and reliable utilization of the ISO's import capacity.

To resolve these concerns, the ISO is considering proposing new rules that would treat the capacity values for expected delivery and maximum delivery (*i.e.,* "energy profile" and "transmission profile") as separate values in market bids and schedules. In the day-ahead market and hour-ahead scheduling process, both the maximum delivery and expected delivery would be subject to the intertie scheduling constraint. Depending on environmental conditions (*e.g.*, wind speed or cloud cover), a variable energy resource's potential output may vary between its installed capacity and zero. Thus, the ISO would limit the variable energy resource's transmission reservation to no more than the maximum capacity stated in its dynamic transfer agreement. A resource that is not a variable energy resource cannot be dispatched above the higher of its self-schedule or maximum capacity offered in its economic bid. For such resources, the ISO proposes to limit the transmission reservation (*i.e.*, the sum of the resource's initial energy schedule and ancillary service awards, plus any additional capacity to allow for a real-time increase in output as sent in dispatches) to no more than the highest offered capacity in its submitted bid. Schedules for dynamic transfers are not required to submit transmission reservations that exceed their expected actual delivery. However, in recognition that a variable energy dynamic resource's maximum delivery can exceed its average delivery, the ISO is proposing to offer the flexibility to schedule the additional transmission capacity that the variable energy dynamic resource chooses to reserve.   When a variable energy dynamic resource does schedule additional capacity beyond its expected average delivery, doing so reduces the transmission capacity that is available to other market participants, and it is appropriate to pay for the transmission reservation.

The scheduling flexibility afforded to variable energy resources under both the existing dynamic scheduling functionality and the proposed enhanced framework discussed immediately above offer as much or more intra-hour flexibility at the ISO's interties than would fifteen minute static schedules. The ISO's dynamic scheduling paradigm essentially makes static fifteen minute schedules unnecessary given that variable energy resources deviations are afforded the ultimate degree of flexibility for deviation. While the ISO's dynamic scheduling option does not permit scheduling coordinators to submit intra-hour schedule changes in economic bid prices, the ISO will accommodate deviations from their initially submitted availability based on the full availability of an intertie's capacity. These features enable the ISO to incorporate greater intra-hour scheduling flexibility at the ties without making significant modifications to ISO's existing market structure.

3. The Commission's Final Rule Must Recognize and Support Efforts to Promote Greater Transmission Scheduling Flexibility Already Underway

Recognizing the need for greater flexibility of hourly intertie schedules, the ISO is engaged with its neighboring balancing authority areas to develop transmission scheduling practices that will provide greater intra-hour scheduling flexibility on a half-hour basis at first. This effort can serve to ultimately transition to fifteen-minute transmission reservation increments as proposed by the Commission. For example, BPA and the ISO are currently evaluating the use of intra-hour scheduling on the California-Oregon Intertie through a joint pilot program intended to facilitate the export of energy from wind resources located in BPA's balancing authority area into the ISO balancing authority area and provide better scheduling and balancing flexibility for variable energy resources. The ISO expects the BPA/ISO pilot will commence on or about October 1, 2011 and last at least one year. During the pilot, BPA and the ISO will conduct an evaluation to confirm whether to extend intra-hour scheduling between BPA and the ISO, through the mechanism of dynamic scheduling to all customers.[11] The final rule must support such efforts, recognizing that the transition to more timely transmission scheduling practices will require significant system and personal changes in the varying regions.

This pilot will use dynamic e-tagging and communication to facilitate intra-hour schedule changes. Participants will submit dynamic e-tags hourly to export power from their wind projects to the ISO balancing authority area. It is the ISO's understanding that BPA will use the dynamic e-tag to create a schedule with the ISO. During the operating hour, participants will update the second half hour of the e-tag to reflect an intra-hour change in schedule through BPA's system (either to increase or decrease) and BPA will adjust the schedule accordingly.

Also, participants under the pilot will be able to schedule in the ISO's day-ahead market, and the ISO will establish the transmission profiles of their dynamic e-tag by pre-scheduling through either the day-ahead market or the ISO's hour-ahead scheduling process. Participants will then establish updated half-hour schedules with BPA, which BPA will communicate electronically to the ISO ten minutes before

[11] The qualifications for participation include, but are not limited, to: (1) a participant must have control over the output of a wind project located within the BPA's Balancing Authority Area; (2) a participant must be a certified scheduling coordinator in the ISO (see http://www.caiso.com/docs/2005/10/28/200510281214421255.pdf to determine eligibility); and (3) a participant must be willing to execute a pilot participant agreement with the ISO and with BPA.

the start of the top-of-hour and bottom-of-hour ramping periods (20-minute ramp between hours, and 10-minute mid-hour ramp). The ISO will electronically confirm the half-hour schedules, which are not expected to be limited by congestion unless derates occur after the pre-scheduling processes have established the transmission profiles of the e-tags. BPA will maintain telemetry to the ISO of each schedule's current delivery, which will reflect static values between ramping periods and then follow the ramping between half-hour schedules. The ISO will echo back the current delivery values, and a final e-tag update at the end of each hour will report the cumulative hourly delivery for interchange accounting. This is a flexible mechanism that the ISO can readily adapt to other intra-hour scheduling periods as balancing authority areas in the western interconnection move from half-hour periods to more granular periods. The ISO believes this mechanism will create a variety of opportunities for flexible scheduling between itself and other balancing authority areas and complement the ISO's five-minute energy dispatch within the ISO's balancing authority area.

The benefits of the ISO and BPA pilot project will include, but are not limited to, sharing in the firming required for variable energy resources that are produced in one balancing authority area, but serve load in another. Currently, the output of variable energy resources outside the ISO balancing authority area are imported only through static hourly schedules, which must be firmed up by the host balancing authority area. The ISO recognizes that the burden associated with firming variable energy resources outside of the ISO area and the associated operating reserve requirement can be significant and can pose a barrier for such imports to the ISO. The ISO is proposing to clarify that variable energy resources can also schedule into the ISO balancing authority area as dynamic transfers, thereby alleviating some of this burden.

While the ISO supports the increased flexibility provided under the fifteen minute intra-hour changes proposed by the Commission, all entities operating in the western interconnection will need to adopt mechanisms to achieve this change. The ISO supports the Commission's efforts to increase transmission service flexibility but it is crucial that the Commission's final rule allow an adequate transition period and permit entities to fashion transmission scheduling reforms that accommodate their particular regional requirements without creating burdensome transition requirements.

However, the Commission's final rule should continue to require all transmission parties to demonstrate their efforts towards identifying and addressing issues posed by any existing transmission scheduling rigidities in their area, which may vary from region to region. In the western interconnection, the delivery and use of power from both existing variable energy resources and new interconnections will require exchanges across many balancing authority area boundaries. Therefore, the western parties must continue in their coordinated efforts to find reasonable solutions that can be implemented equally without undue burden to the neighboring parties. As part of its directive, the Commission should consider whether or not a regional technical conference or conferences may be an appropriate procedural mechanism to facilitate resolving technical issues and developing compliance timelines.

B. Power Production Service-Capacity

The ISO supports the Commission's effort to require power production forecasting from variable energy resources. This proposed reform is limited to those public utility transmission providers seeking to require a subset of transmission customers to purchase, or otherwise account for, different volumes of generator regulation reserve service under proposed Schedule 10 (discussed below in part III.C). The Commission asserts that this proposed reform recognizes that variable energy resource power production forecasting may not be necessary in all parts of the country at this time (*e.g.*, those regions with limited production from variable energy resources). The Commission proposes to revise the *pro forma* Large Generator Interconnection Agreement (LGIA) to require interconnection customers whose generating facilities are variable energy resources to provide certain meteorological and operational data to the public utility transmission providers with whom they are interconnected.[12]

The ISO supports the Commission's proposal to require interconnection customers whose generating facilities are variable energy resources to provide certain meteorological and operational data to the public utility transmission providers with which they are interconnected. As part of its final rule, the Commission should clarify that while the proposed LGIA amendments reflect a mechanism in which the data requirements may be met under the *pro forma* OATT, public utility transmission providers may demonstrate that the requirements may be met through alternative tariff-based means. For example, the Commission recently approved ISO tariff provisions that require all eligible intermittent resources to provide to the ISO real-time operational and meteorological data necessary to forecast variable energy resource power production over a variety of time periods.[13] Previously, only variable energy resources participating in the ISO's participating intermittent resource program were required to submit a power production schedule.

[12] VERS NOPR at P 60.

[13] *Cal. Ind. Sys. Operator Corp.*, 131 FERC ¶ 61,087 (2010); compliance filing accepted by letter order issued on January 19, 2011 in Docket No. ER10-319.

The Commission's April 30, 2010 order authorizes the ISO to extend these requirements to all wind and solar resources larger than 1 MW.[14] These data requirements are contained in Appendix Q and sections 9.3.10.3 and 9.3.10.3.1 of the ISO tariff and consist primarily of (1) the obligation to install specified forecasting and telemetry equipment and to communicate relevant data to the ISO and (2) a reduction in the threshold for reporting a forced outage of an eligible intermittent resource with total capacity of greater than 10 MW from the current outage capacity level of 10 MW to 1 MW. The Commission must not undo these recently approved data submission requirements in the final rule. The Commission found these requirements to be just and reasonable, and the NOPR does not identify any changed circumstances or offer any new rationale as to why these data submission requirements would no longer remain just and reasonable and appropriate for variable energy resources in order to support effective and reliable integration of variable energy resources.

As explained by the ISO in its March 1, 2010 submission to the Commission, poor data quality and missing turbine availability information degrades forecast accuracy in both the day-ahead and hour-ahead time frames by approximately 20 percent. Moreover, the algorithms and neural networks of many forecast service providers engage in a training period to correlate the characteristics of an intermittent resource to its fuel source. Once the forecast service provider's algorithm has "learned" the resource's characteristics, undisclosed changes to the energy availability will affect the forecast. Accordingly, the use of a threshold reporting

[14] In its order accepting the proposed tariff provisions, the Commission required the ISO to make the following further revisions, which the ISO made in its compliance filing on May 27, 2010 and which the Commission accepted by letter order on January 19, 2011: (1) exclude small conduit hydroelectric facilities from the definition of eligible intermittent resources; (2) make clear that only intermittent resources subject to the ISO's participating generator requirements are subject to the expanded data requirements; (3) defer the effective date for the requirement for expanded forced outage reporting from the ISO's requested date of February 1 to July 1, 2010; and (4) incorporate proposed exemptions into the tariff rather than the ISO's business practice manuals.

obligation less stringent than 1 MW would increase the likelihood that the forecasting algorithm would accumulate inaccurate data (*i.e.*, undisclosed outages) in its knowledge base, which would lead to additional errors in energy forecasts.[15]

While the ISO's data requirements for eligible intermittent resources are not tied to the provision of *pro forma* OATT Schedule 10 services as discussed by the Commission in its NOPR, the ISO's market structure already provides the flexibility for obtaining regulation services. The increased situational awareness provided by the power production forecast requirements is used in the ISO markets through unit commitment and dispatch processes, which leads to more efficient dispatches and the procurement of reserve products in a more reliable and efficient manner. This data has benefited the ISO's system operations by improving the ISO network and market model. Forecasts from renewable resources now serve as key elements to the ISO's network and production modeling efforts both in the days prior to the operating day and during the operating day. In the real-time, forecast data is crucial to account for increases or decreases in anticipated production. The ISO manages forecast variability from renewable resources based on five major areas of wind farms and major solar fields in the balancing authority area rather than by specific resource. The ISO then biases load forecast information net of variable energy resource generation to account for the expected variability. The ISO's real-time unit commitment and real-time dispatch process this information to award ancillary services and dispatch resources for energy. With the increased presence and accuracy of power production data from variable energy resources, the ISO will be able to refine its efforts in production modeling.

[15] *See, Cal. Ind. Sys. Operator Corp.,* 131 FERC ¶ 61,087 (2010).

The ISO also implemented a renewable desk on its control room floor on November 29, 2010. Using available data and forecast capabilities, the renewable resource coordinators have been able to forecast in some instances when the ISO will be losing over 100 MW of wind or solar generation and thereby allow the real-time generation dispatcher to procure more energy in that period to avoid use of operating reserves and then recovering those reserves.

In the NOPR, the Commission states that it does not propose to require retroactive changes to large generator interconnection agreements that are already in effect.[16] However, the Commission seeks comment as to whether this approach would prevent public utility transmission providers from effectively implementing power production forecasting. The ISO believes that, in areas where there is a significant presence of variable energy resources, the meteorological data requirements imposed on generators should apply uniformly with no exemptions for existing generators. The benefits of of meteorological data to the transmission provider are diluted if only a smaller portion of the population has the necessary technology in place. Especially in areas such as California where already faced with a 20 percent renewables portfolio requirements, a rule that only applies prospectively will eliminate the ability to obtain visibility into a substantial portion of the variable energy fleet. It is possible that at the early stages of penetration of variable energy resources in a given region may not have a need for meteorological data from the early entrants. However, over time, the increase in presence of such resources will pose operational challenges if the transmission provider lacks visibility out of a significant portion of the fleet. The lack of visibility into the existing fleet would prevent the ISO from dispatching its resources optimally to meet the operational

[16] VERS NOPR at P 64.

challenges posed by all its variable energy resources, thereby potentially unfairly providing disparate treatment to similarly situated variable energy resources simply because of the lack of visibility. From an operational perspective, the fact that a variable energy resource entered the grid earlier does not mean that there is any less of a need for tools to better predict their performance. The ISO must be able to apply forecasting and data production tools to all its variable energy resources in order to operate its grid optimally and reliably on any given day. Therefore, there should be no grandfathering of the existing fleet and all meteorological data requirements should apply to all existing and new entrants.

The ISO also believes that restricting these data requirements to generators that are 20 MW or above is not reasonable in all areas of the country. The final rule should therefore allow for parties to propose a lower threshold, whether the threshold is maintained in the tariff or in the LGIA as proposed by the Commission. This flexibility is necessary because if the threshold is set too high, information regarding significant capacity on the system will be missed, thereby rendering the requirement ineffective and jeopardizing any effort to address problems in a comprehensive and effective manner. A substantial part of wind and solar resources consist of aggregations of smaller sized individual resources as low as 1 MW or less that comprise larger wind or solar farms. Currently the ISO has 92.72 MW of wind (2.5% of installed capacity) and 90.7 MW of solar (18% of installed capacity) that are 20 MW of less. The 20 MW resource specific proposed thresholds would preclude the collection of such data from a large amount of resources. As such, the ISO would lack visibility from over 20 percent of the current variable energy resources fleet. As the fleet expands with greater number aggregations of smaller resources, the ISO would lose visibility of a greater and greater portion of its variable energy resources fleet. This would undermine the ISO's ability to incorporate uniform production data into its market systems creating greater unexpected upward or downward swings in output that could not be adequately addressed. The Commission's final rule should therefore allow parties to demonstrate that, based on their existing and expected configuration of the variable energy resources fleet, a lower threshold is necessary to ensure adequate visibility is afforded to the transmission provider.

The Commission also seeks comment on whether public utility transmission providers should be allowed or required to share variable energy resource related data received from interconnection customers with other entities, like the source or sink balancing authority area for a transaction, or a government agency, such as NOAA, assuming confidentiality is protected.[17] The ISO believes the sharing of such data, subject to proper measures to protect the confidentiality of the data, with government agencies that have similar mandates for the integration of variable energy resources is both crucial and appropriate. Devices such a hub height meteorological tower could be developed out of such collaborative efforts that will provide better ability to forecast accurately boundary layer conditions for all wind resources participating in the effort. Similarly, the development of a solar data collection network would help with the advancement of solar energy forecasting at surface level.

The ISO also understands that other market participants may benefit from forecasts of variable energy resource production. However, the ISO has found that sharing specific production data with other customers raises concerns that the data are commercially sensitive as they effectively provide the expected output of a specific facility. Because of the direct relationship between the weather and the

[17] VERS NOPR at P 63.

production of the resource, in essence, the meteorological data provided by a specific resource are viewed to be similar to the production data of other generator resources, which the ISO does not share with other market participants. Therefore, in order to balance the competing interest of protecting the confidential data, yet provide sufficient information on the expected variability of generation resources, the ISO is in the process of preparing for the release of aggregate level data on the forecast of variable energy resources (Data Release Phase 3) The ISO will utilize the meteorological data provide by individual resources to develop a wind and solar forecast for each of its three trading hubs. The trading hub forecast will not simply be the sum of all individual resources rather the trading hub forecast will take into consideration diversity benefits. As a result, the ISO will release to market participants a supply forecast that more accurately reflects the system level impact of wind and solar supply, while also not sharing commercially sensitive data from individual resources. The final rule should not preclude the ISO's proposed approach to addressing this issue.

The Commission also proposes to amend the *pro-forma* LGIA to add a new definition of Variable Energy Resource to Article 1, add a new Article 8.4, Provision of Data from a Variable Energy Resource, and amend the table of contents. (P 64) The proposed definition is:

> a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. [18]

The ISO believes this definition properly captures characteristics of the renewable resources that should be subject to the Commission's proposed reforms.

[18] VERS NOPR at P 64.

However, the ISO proposes that the Commission should clarify the definition by replacing the phrase "by an energy source that" with the phrase "by a~~n energy~~ fuel source that." This change would clarify that the three conditions that follow that statement pertain to the fuel source and not the nature of the facility itself. With this change it would be clear, for example, that the definition does not describe the storage facility itself, but rather the variable energy fuel source that may be stored by a storage facility. The ISO also believes that the definition appropriately does not distinguish between solar thermal and other solar facilities. While solar thermal resources store the solar thermal heat they do not store the solar irradiance itself, which is the fuel source for the solar thermal facility. As such, the solar thermal facility would appropriately fall under this definition. The Commission's final rule should clearly stipulate that the definition captures such facilities.

The Commission also proposes to revise the *pro forma* LGIA to require interconnection customers whose generating facilities are variable energy resources to report to the public utility transmission provider any forced outages that reduce the generating capability of the resource by 1 MW or more for 15 minutes or more. The Commission states that this proposal is similar to a recent ISO proposal accepted by the Commission on April 30, 2010. The ISO agrees with the Commission that the provision of variable energy resource outage data to this level of granularity will allow a public utility transmission provider to ascertain the extent to which variable energy resource current power production is a result of unit availability as opposed to changing weather conditions.[19] The ISO requests that the final rule not disturb the ISO's tariff requirements.

[19] VERS NOPR at P 62.

C. Generator Regulation Service-Capacity

In the NOPR, the Commission also seeks to bring consistency to the manner in which transmission providers carry out their obligation to offer transmission customers with the capacity reserves associated with the provision of generator imbalance service. In Order 890-A, the Commission clarified that transmission providers can propose on a case by case basis the ability to assess regulation charges to *generators* selling in the balancing authority areas as well as generators selling outside of the balancing authority area.[20] However, having reviewed a number of proposals to address this issue and only accepting a few, the Commission seeks to bring consistency to the manner in which utilities carry out their obligation to provide generator regulation service.

The Commission's proposed prescriptive regulation is targeted to non-market regions that operate pursuant *pro forma* OATT transmission tariffs by proposing the inclusion of Schedule 10—Generator Regulation and Frequency Response Service into the *pro forma* OATT. The Commission recognizes that on many transmission systems, especially those that do not have a significant number of transmission customers that export energy, public utility transmission providers already recover the costs of providing regulation service to transmission customers serving load on their systems through Schedule 3 of the *pro forma* OATT. The proposed reform would require public utility transmission providers to file the additional Schedule 10, setting forth the transmission provider's obligation to offer generator regulation service and the rate at which the service would be provided.[21]

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[20] VERS NOPR at P 70.

[21] VERS NOPR at P 85.

The ISO operates a comprehensive energy and ancillary services market that provides the flexibility sought by the Commission in requiring the adoption of Schedule 10 in non-market regions. The proposed Schedule 10 complements the series of schedules offered under the *pro forma* OATT for the provision of ancillary services, energy imbalance for load serving entities, and generator imbalance to recover energy costs for dealing with generator imbalances. As discussed in the ISO's compliance filing to Order No. 890 and as approved by the Commission,[22] the ISO's energy and ancillary services market meets or exceeds these requirements.

In the case of generator regulation service, the ISO maintains sufficient resources immediately responsive to the ISO's energy management system control to provide sufficient regulation service to allow the ISO balancing authority area to meet NERC and WECC reliability standards, including any requirements of the Nuclear Regulatory Commission, by continuously balancing resources to meet deviations between actual and scheduled internal load and exports, and to maintain interchange schedules. Under the ISO's comprehensive energy and ancillary services markets, the ISO's regulation service already accounts for any variability in load and generation to ensure that sufficient immediately responsive capacity is online to meet whatever variability should arise. As the Commission recognized in *Westar*, the enhancements offered through the proposed Schedule 10 already exist in fully developed energy and ancillary services markets.[23]

Under the ISO's ancillary services market structure, the ISO allocates costs associated with regulation only to load and exports. This cost allocation structure was developed at a time when most of the variability was triggered by load forecast

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[22] *See e.g., Cal. Ind. Sys. Operator Corp.*, 123 FERC ¶ 61,180 (2008).

[23] *Westar Energy, Inc.*, 130 FERC ¶ 61,215 at P 35 (2010).

error. However, as discussed in the NOPR, the increased penetration of variable generation challenges this assumption and elicits an analysis of whether the existing ancillary services products and cost allocation methods are sufficiently robust to address the increased generation variability anticipated with increased variable energy resource penetration. The ISO is engaged in a two-phase stakeholder process to consider any market enhancements necessary for integration of increased variable energy resources on its system. In the first phase currently underway, the ISO is examining market enhancements necessary for the integration of additional variable energy resources. The ISO is planning to address the adequacy of its ancillary services products and cost allocation in Phase 2 of its stakeholder process that will commence soon. During that process, the ISO anticipates that stakeholders and the ISO will discuss whether the design of its ancillary services products account for the different amounts of overall variability between load and generation and among the different types of generation resources.

The Commission recognizes in its NOPR that as a general matter regulation reserve costs should be allocated to transmission customers consistent with cost causation principles, but it does not propose to mandate a particular method for apportioning the volume of regulation reserves of proposed Schedule 10. The ISO requests that the Commission continue to allow each transmission provider to determine a cost allocation that is suitable for its specific market structure and the facts circumstances conditions and resource mix in its region.

Finally, the Commission seeks comments from NERC and industry stakeholders on the steps needed to resolve the confusion regarding the use of contingency reserves to manage extreme ramp events of variable energy resources. The Commission seeks to understand better the extent to which some additional type of contingency reserve service (beyond the services provided under Schedule 5 and 6 of the *pro forma* OATT) would ensure that variable energy resources are integrated into the interstate transmission system in a non-discriminatory manner while remaining consistent with NERC Reliability Standards.[24] The current procurement target for spinning and non-spinning operating reserves defined by WECC is set at the greater of the most severe single contingency or 5% of load served by hydro generation plus 7% of load served by thermal generation. It is unlikely that wind or solar farms would reach the threshold of the most severe single contingency and thus set the ISO procurement requirement. Moreover, the ISO cautions against the expansion of contingencies to such events as it may result in the overuse of contingency reserves potentially impacting reliability as such crucial resources are exhausted.

Moreover, the ISO's recent *20 Percent RPS Study* demonstrates that while additional ramping or load following products may be necessary in the ISO market, additional operating reserves that are ten minute ramp products will not suffice. The increased variability posed by wind and solar resources requires more timely flexibility that and faster ramping requirements to meet the operational requirement.[25]

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[24] VERS NOPR P 100.

IV. Conclusion

The ISO appreciates this opportunity to comment on the Commission's proposed reforms to eliminate barriers that may impede the reliable and efficient integration of variable energy resources into the electric grid. The ISO respectfully requests that the final rule reflect the flexibility requested by the ISO in its comments.

Respectfully submitted,

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March 2, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 2nd day of March, 2011.

/s/ Susan L. Montana

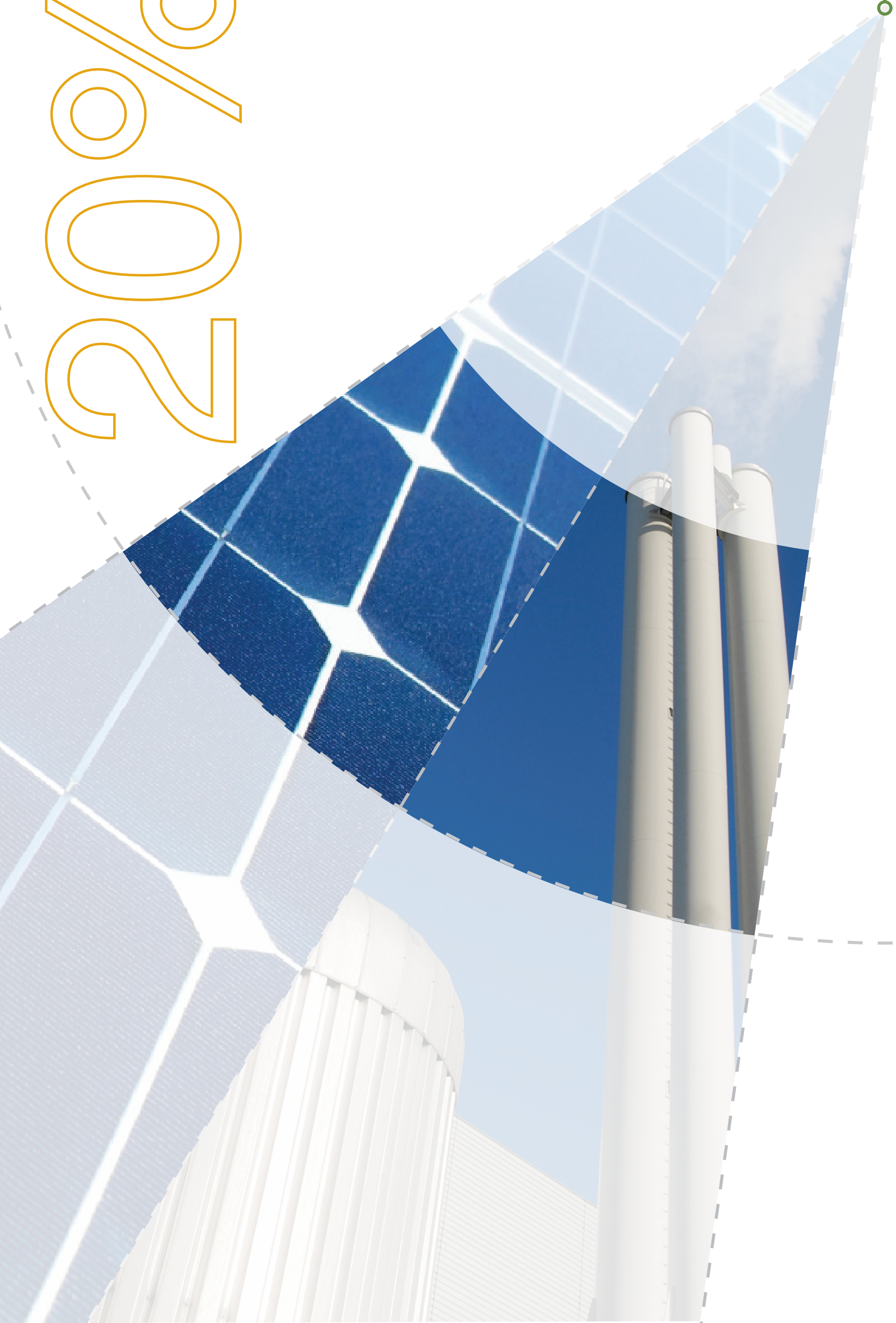
Susan L. Montana

20% RPS

INTEGRATION OF RENEWABLE RESOURCES

Operational Requirements and Generation Fleet Capability at **20% RPS**

August 31, 2010



California ISO
Your Link to Power

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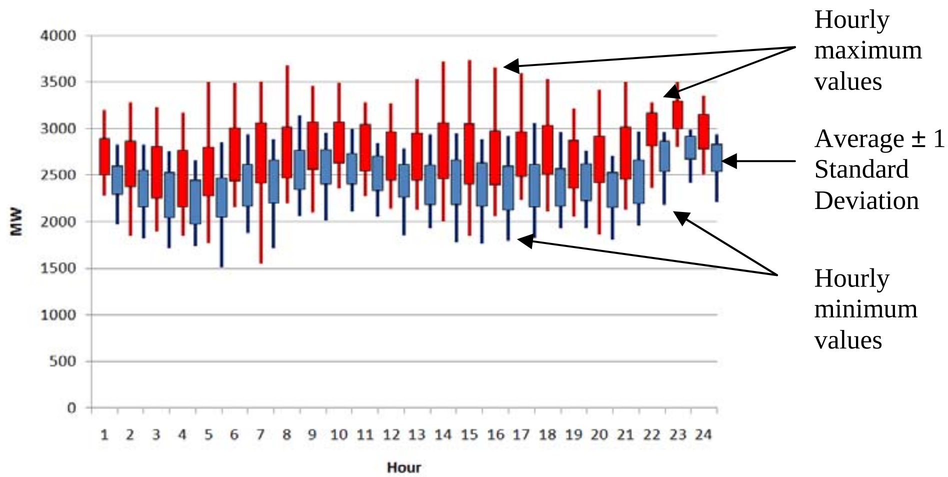
Preliminary Notes and Key to Figures

1. A number of the technical terms in this report refer to market products and market scheduling or operational procedures used by the ISO. Typically, such references are capitalized in ISO papers and reports to indicate that they are a defined term in the ISO Tariff. In this report, most technical terms are not capitalized and the use of acronyms is minimized to facilitate reading. For example, Regulation Up and Regulation Down are ancillary service products procured in the ISO markets, but are not capitalized in the report.

2. Many of the figures in the report represent data in the format of a “stock chart” or “whisker chart” that shows certain distribution statistics for a sample of simulated values or actual market results, typically shown by hour of season. In the example below, the top of the red or blue lines is the maximum data point in a sample, while the bottom of the red or blue lines is the minimum data point. The red and blue bars represent two standard deviations: the average plus one (1) standard deviation and the average minus one (1) standard deviation. Many of the figures, such as the one below, show these results for two simulated years that are being compared, in which case the results for each year are in different colors.



3. The figures in the report that use the format shown above are either measuring operational requirements in the upwards (positive) direction, which represent “incremental” energy or reserves, or in the downwards (negative) direction, which represents “decremental” energy or reserves. The figure above is for incremental energy, hence the vertical axis (or y-axis) is measuring positive values. For figures that show decremental energy or reserves, the y-axis shows negative values and the maximum and minimum of the sample data is reversed (i.e., the maximum requirement is the most negative).

4. In several sections of the report, readers need to distinguish between simulated results and actual results for the same or similar years. For certain simulations, the study benchmarks the results in the 20 percent RPS target year, assumed to be 2012, by simulation of prior years without the additional renewables, which in this study is 2006 and 2007. The study also includes analysis of actual ISO market and system conditions for selected periods up to 2010. The simulations of prior years, such as 2006, have been validated by comparison to actual conditions in those years, but there are differences due to modeling assumptions, as noted in the report.

Acronyms and Selected Definitions

ACE	Area Control Error
ADS	Automatic Dispatch Signal
AGC	Automatic Generation Control
BAA	Balancing Authority Area
BPM	Business Practice Manual
CEC	California Energy Commission
CPS	Control Performance Standard
CPUC	California Public Utilities Commission
DA	Day Ahead
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
FNM	Full Network Model
GW, GWh	Gigawatt, Gigawatt-hour (GW = 1,000 MW)
HA	Hour Ahead
HASP	Hour Ahead Scheduling Process
IFM	Integrated Forward Market
ISO	Independent System Operator
MW, MWh	Megawatt, Megawatt-hour (MW = 1,000 kW)
NERC	North American Electric Reliability Corporation
OTC	Once Through Cooling
PIRP	Participating Intermittent Resource Program
Pmin; Pmax	minimum and maximum operating level of a generator
PNNL	Pacific Northwest National Lab
PV	photovoltaic
QF	Qualifying Facility
RPS	Renewables Portfolio Standard
RT	Real Time
RTUC	Real Time Unit Commitment
WECC	Western Electricity Coordinating Council

Executive Summary

Under California's existing Renewables Portfolio Standard (RPS), utilities must supply 20 percent of all electricity retail sales from eligible renewable resources by 2010, with compliance expected in the 2011-2012 timeframe.[1] Much of the additional renewable generation to meet the RPS goal will be wind and solar technologies with variable operating characteristics that complicate electric system operations. As the entity responsible for the reliable operation of the bulk electric power system for most of the state, the California Independent System Operator Corporation (ISO) is focused on ensuring that the electric system is able to operate reliably with these additional renewable resources. This report represents an essential step in that effort. It describes the technical effects on system operations and wholesale markets of increases in wind and solar generation to achieve the 20 percent RPS target and evaluates the capability of the current generation fleet to maintain reliability under these changed conditions.

The chart below (Figure ES-1) shows the expected technology mix of renewable resource capacity assuming the 20 percent RPS is achieved in 2012 and compares it to the renewable resources in 2006, which is the year used to benchmark a number of study results.[2] Much of the expansion in renewable energy will come from variable energy resources, namely wind and solar technologies. The integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources, than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

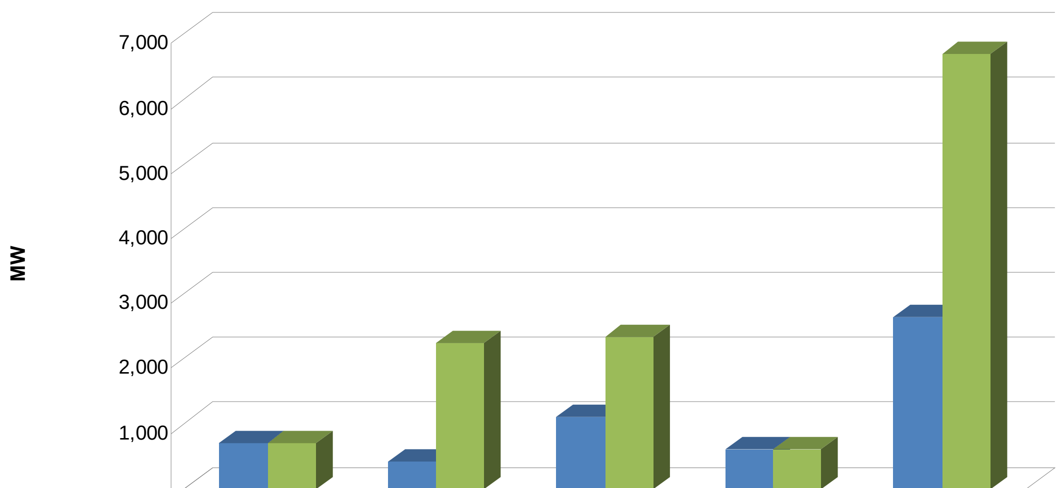
To understand the extent of these impacts at 20 percent RPS, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study released in 2007 that focused on the operational and transmission

[1] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[2] The year 2006 was chosen as the benchmark year to facilitate easier comparison with prior ISO studies. This year was both a high hydro year—hence is useful as a base-year to examine the interaction of hydro and higher levels of wind production in overgeneration conditions—and had the highest annual peak load to date.

requirements of wind integration ("2007 Report").[3] This study builds on those prior efforts. The purpose of this study is to assess the operational impacts of an updated renewable resource portfolio that includes 2,246 MW of solar and to evaluate in more detail the operational capabilities of the existing generation fleet, as well as changes to their energy market revenues. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

The results presented in this report have significant operational and market implications. From an operational perspective, the ISO is concerned with the extremes of potential impacts—in particular large, fast ramps that are difficult to forecast. A key purpose of the simulations in this study is to estimate the operational capabilities and clarify possible changes to market and operational practices to ensure that the system can perform as needed under these conditions, even if they rarely occur. Hence, the study identifies the maximum values of simulated operating requirements, such as load-following and regulation, by operating hour and by season. In addition, to clarify how more typical daily operations may change, distribution statistics are provided for most of the simulated requirements and capabilities to facilitate both operational and market preparedness.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure ES-1: Renewable Resource Capacity (MW) in 2006 and 2012 (expected)

[3] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007), available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

Key Findings and Results

- The modeling of 2,246 MW of solar resources under the 20 percent RPS changes the operational requirements, compared to the incremental wind-only results presented in the ISO's 2007 Report.

- The changes to the operational requirements due to additional solar resources take place in the mid-morning and early evening hours. The ramp up in solar generation in the mid-morning can increase the load-following down and regulation down requirements compared to the case with wind generation alone that was studied in 2007. Similarly, the solar ramp down in early evening can increase the load-following up and regulation up requirements compared to the case with wind alone.

- In other hours, the combination of solar and wind resources can lessen operational requirements, because solar resources are ramping up when wind resources are ramping down, and vice-versa.

- The combination of increased production of wind and solar energy will lead to displacement of energy from thermal (gas-fired) generation in both the daily off-peak and on-peak hours. Due to this displacement and to simultaneous reduction in market clearing prices, there may be significant reductions in energy market revenues to thermal generation across the operating day in all seasons.

Load-following Impacts

A core operational and market function of the ISO is to forecast system load and renewable production day-ahead and in real-time, and then to ensure that sufficient generation and non-generation resources are committed such that intra-hourly deviations from hourly schedules can be accommodated by those resources under ISO dispatch control. These deviations can take place in the upward or downward direction. Currently, the intra-hourly deviations are largely caused by changes in load, hence the term "load-following." With additional variable energy resource production, the *net* load-following requirement—i.e., the requirement due to load schedule deviations plus wind and solar schedule deviations—could increase substantially in certain hours due both to the variability of wind and solar production and forecast uncertainty. Unless otherwise indicated, all results on load-following requirements in this report are of net load following.

- The simulated maximum load-following up and load-following down ramp rates for 2012, by season in which they occur, are 194 MW/min (summer) and -198 MW/min (winter), respectively.[4] These represent possible increases at times in the range of ± 30-40 MW/min over the ramp rates simulated for the year 2006.

[4] The load-following ramp rate measures the change in energy requirements between 1-minute intervals within the 5-minute dispatch intervals in an operating hour. The details behind the calculation of load-following ramp rate can be found in Section 3.

- While the system must be capable of delivering these capabilities, such ramp rates will not be experienced in every operational hour, nor sustained over the entire hour.

- One measure of the upper bound on the duration of the increased ramp rates is the hourly load-following capacity requirement.[5] The maximum hourly load following up and load-following down capacity requirements for 2012 are 3737 MW and -3962 MW (both summer season requirements), respectively. For the summer months, the maximum increase in the hourly capacity requirement when 2012 is compared to 2006 is 845 MW for load-following up and -930 MW for load-following down. As shown in Figures ES-2 and ES-3, in the summer, the highest requirements are typically in the morning and evening wind and solar ramp periods.

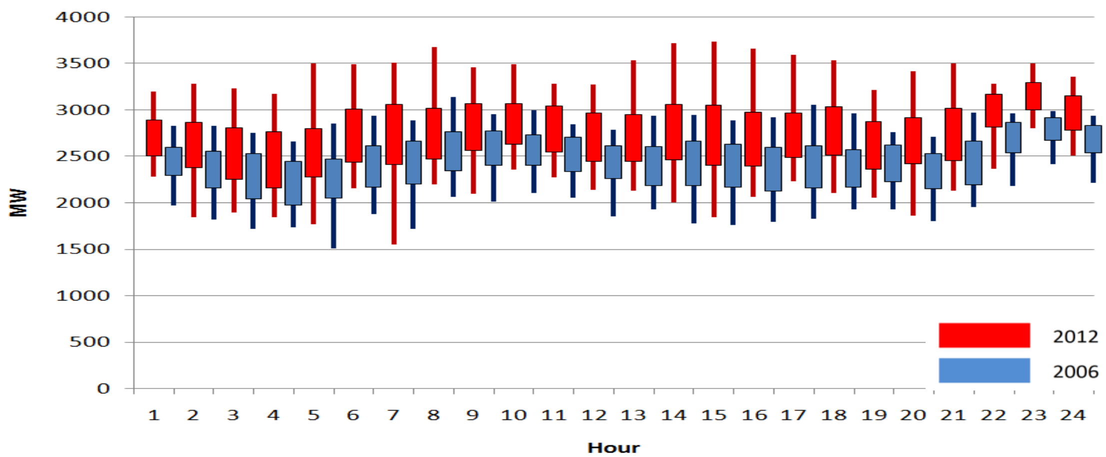


Figure ES-2: Simulated Load-following Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

[5] The hourly load-following capacity requirement is defined as the maximum difference between each hour-ahead schedule and the 5-minute real-time schedules within that hour. This can be measured in the upward or downward direction from the hourly schedule.

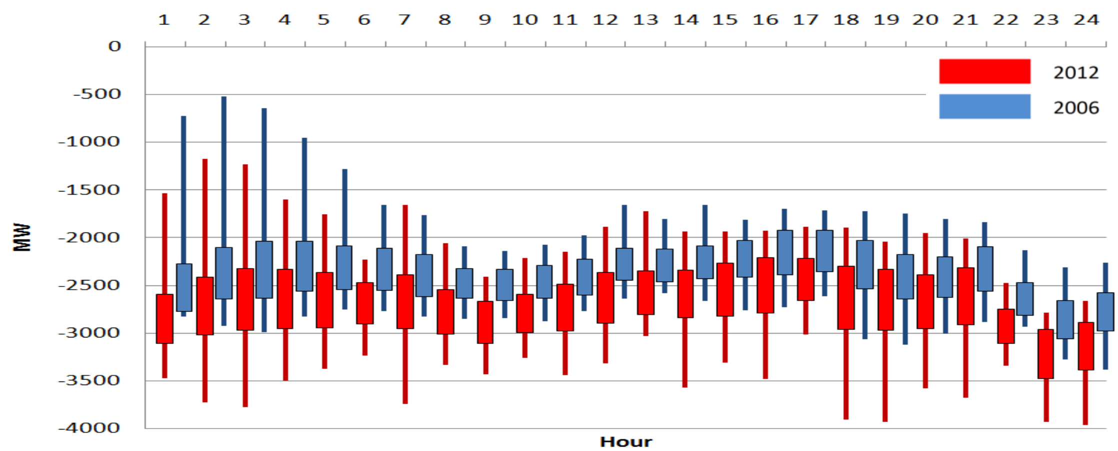


Figure ES-3: Simulated Load-following Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- When the simulated maximum requirements for all hours in the season are taken into account, the percentage increase in total load-following capacity requirements in the summer season between 2012 and 2006 is estimated at 12 percent for load-following up and 14 percent for load-following down; the results for all seasons are shown in Table ES-1.[6]

Table ES-1: Percentage Increase in Total Seasonal Simulated Operational Capacity Requirements, 2012 vs. 2006

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

- The historical 5-minute load-following capability[7] of the generation fleet, was measured for the period between April 1, 2009, and June 30, 2010. Figures ES-4 and ES-5 show the 5-minute load-following up and load-following down capability for units on 5-minute dispatch in the summer months during that period.[8] The results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up

[6] The total is defined as the sum of the maximum simulated load-following capacity requirement in each hour of the season (2160 hours = 90 days × 24 hrs./day for a 90 day season); see Section 3 for details.

[7] The 5-minute load-following up (down) capability for a dispatch interval is the *maximum* capability that is available in the up (down) direction in 5-minutes, subject to the ramp rates and operational constraints of the dispatched resources.

[8] In the figures, each bar corresponding to an operating hour represents 1080 measurements for a 90 day season; e.g., for hour 1, each 5-minute interval of that hour for each of the 90 hour 1s in the season.

requirements simulated for 20 percent RPS within 20 minutes or less.[9] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

- The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min, which is -845 MW/5 min. These high load-following down requirements are often for the mid-morning hours. Under the current practice of self-scheduling generation rather than allowing them to be operated through economic dispatch, the 5-minute downward ramp capability as shown in Figure ES-5 could be well below the requirement of -845 MW during some of the mid-morning hours.

- Figures ES-5 and ES-6 compare the 5-minute load-following down capability, limited and not limited by self-schedules, respectively. Figure ES-6 suggests that current load following down capability could be more than doubled in many hours if all thermal generation were fully dispatchable. The implication is that to accommodate the increased variability at 20 percent renewable energy, the level of self-schedules will have to decrease.

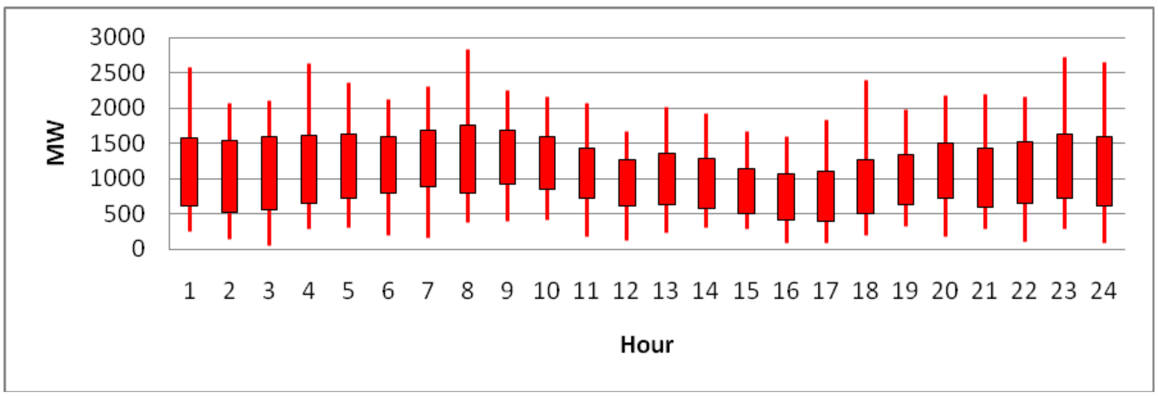


Figure ES-4: Summer 5-Minute Load-following Up Capability: June 2009-August 2009, June 2010

[9] For example, if the 3,737 MW maximum load-following up capacity has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

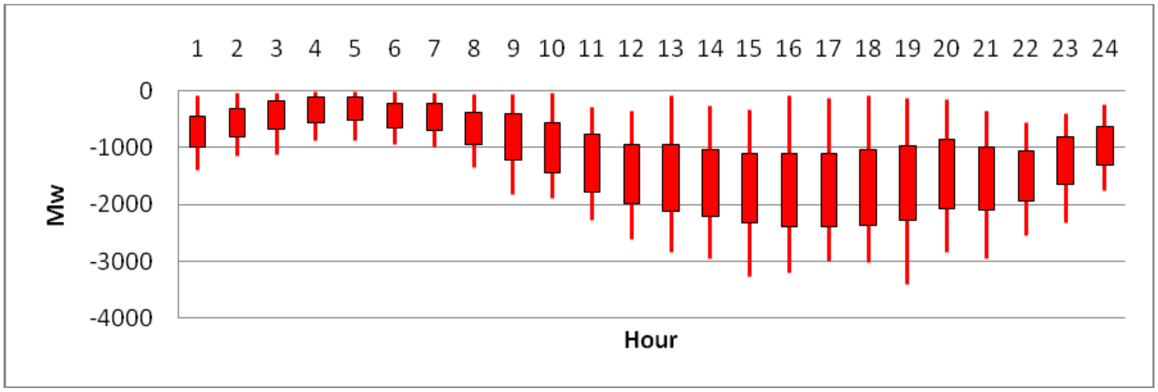


Figure ES-5: Summer 5-Min Load-following Down Capability (Limited by Self Schedules): June 2009-August 2009, June 2010

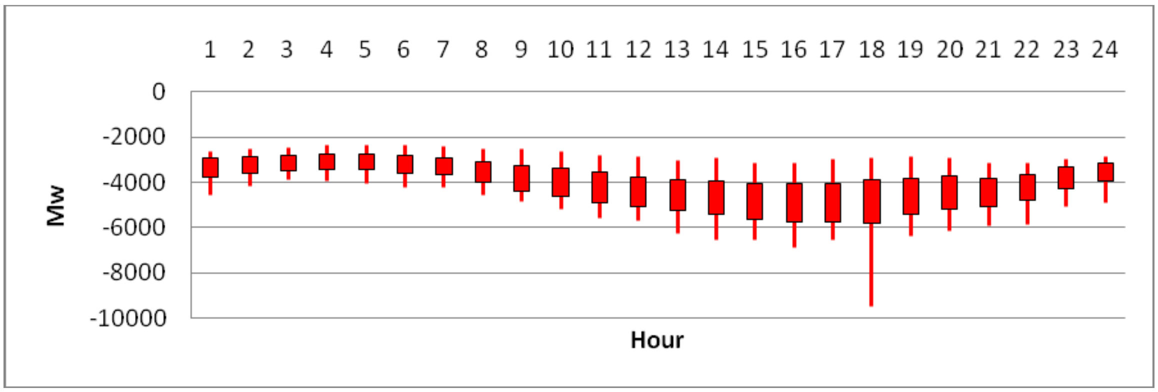


Figure ES-6: Summer 5-Minute Load-following Down Capability (not limited by Self-Schedules): June 2009-August 2009, June 2010

To further evaluate the load-following up and down capabilities of the ISO generation resources, the ISO also conducted production simulations for selected days that included simulation of 5-minute dispatch. The production simulation assumed that all thermal generation were fully dispatchable (i.e., maximum operational flexibility), but that all other classes of generation were following fixed schedules.

- Figure ES-7 shows the load-following capability over one such simulated day, May 28, 2012. This figure shows the capability of the dispatchable generators to move from one 5-minute dispatch to the next, subject to ramp and other operational constraints.[10] The 5-minute load-following down capability is at or

[10] It should be noted that Figure ES-7 shows the simulated load-following capability for each 5-minute period in the day, whereas Figure ES-5 shows the historical hourly distribution of 5-minute load-following capability.

close to zero during the morning hours from 4 a.m. to 10 a.m.[11] as shown. If current scheduling practices continue, this simulated capability would be further diminished due to self-scheduling. Production simulation results for additional days can be found in Section 5 and Appendix C.

- Figure ES-8 then shows the simulated overgeneration on May 28, 2012 due to the shortage of load-following down capability. Insufficient capability to ramp down manifests itself as overgeneration in the production simulations.[12] This figure also shows the regulation down procurement (green line) and the CPS2[13] violation threshold (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., for the other hours in the day, the overgeneration can be covered by the procured regulation down or allowed to result in an Area Control Error (ACE) violation, if it is not sustained. Only significant overgeneration sustained over 10 minutes is likely to result in the curtailment of generation.

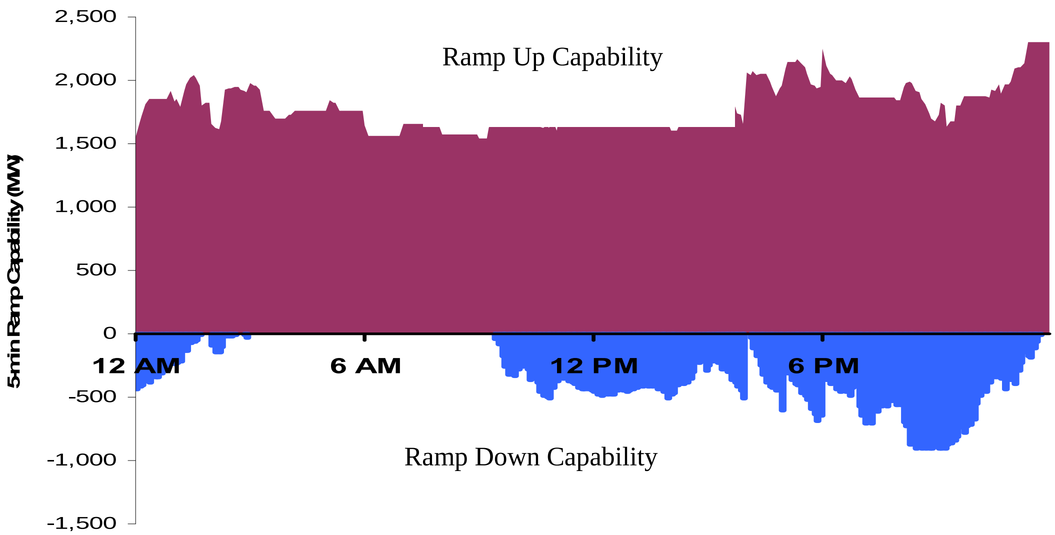


Figure ES-7: 5-minute ramp up and down capability for May 28, 2012

[11] The low load-following down capability in the simulation is because very few dispatchable generators are online and most are already operating at or close to their minimum load point. When operators can no longer dispatch resources downwards, the operating condition called overgeneration exists and is managed through additional measures, including curtailments of renewable resources.

[12] As discussed further in Sections 2 and 5, there were further constraints in the model that affected the overgeneration result.

[13] NERC Control Performance Standard 2.

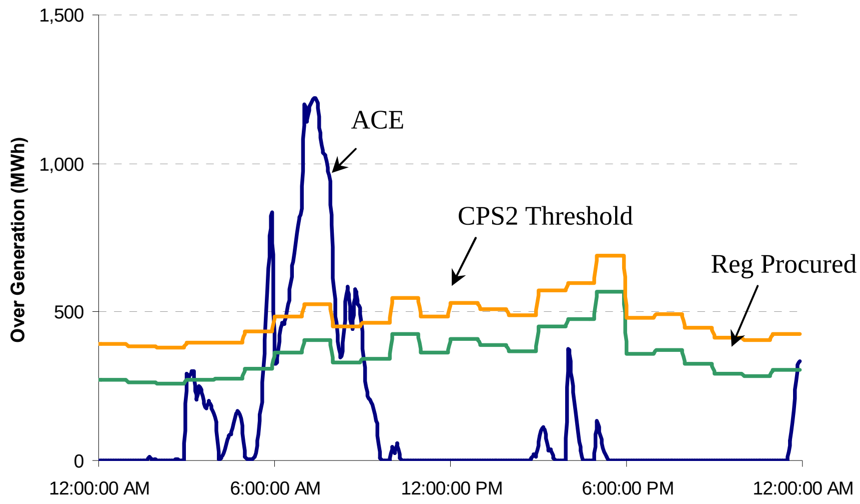


Figure ES-8: Detailed overgeneration analysis of May 28, 2012

- For the year, production simulations show that load-following down shortages will result in less than 0.02 percent of renewable generation (approx. 10 GWh) potentially needing to be curtailed under assumed conditions. The production simulations did not identify any load-following up shortages.

Regulation Impacts

In real-time, the ISO operators issue dispatch instructions to generators every 5 minutes based on forecasts of demand and supply that are available in the prior minutes. The second-by-second variability of load, net of wind and solar production, within those 5-minute intervals is balanced by units on automatic generation control (AGC) that can provide regulation as needed in the upwards or downwards direction.

- The maximum hourly regulation up and regulation down capacity requirements in 2012, which take place in different seasons, are 502 MW (spring) and -763 MW (summer), respectively. The largest increases in these requirements between the 2012 and 2006 simulations are 270 MW (spring) and -457 MW (summer). These results are found in Appendix A-1, tables A-1 to A-8.

- As shown in Figures ES-9 and ES-10 for the summer 2012 season, the highest regulation up requirements are typically in the morning and evening wind and solar ramp periods, while regulation down requirements are concentrated in the mid-afternoon hours. Hour 18 consistently results in very high regulation down requirements in the summer simulations, due largely to the consistently fast wind ramp up experienced in that hour.

- The maximum hourly simulated regulation up and regulation down ramp rates in 2012 are 122 MW/min (spring) and -97 MW/min (summer), respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

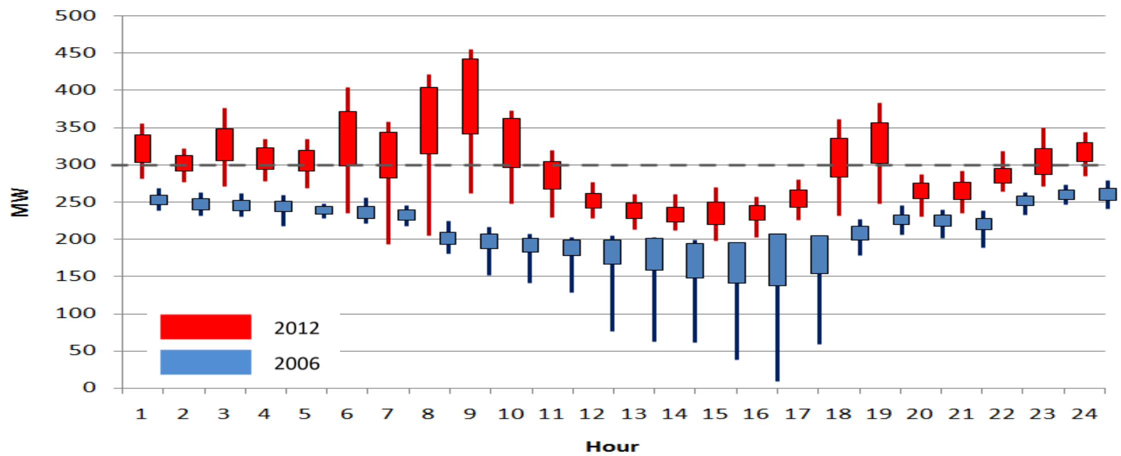


Figure ES-9: Simulated Regulation Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

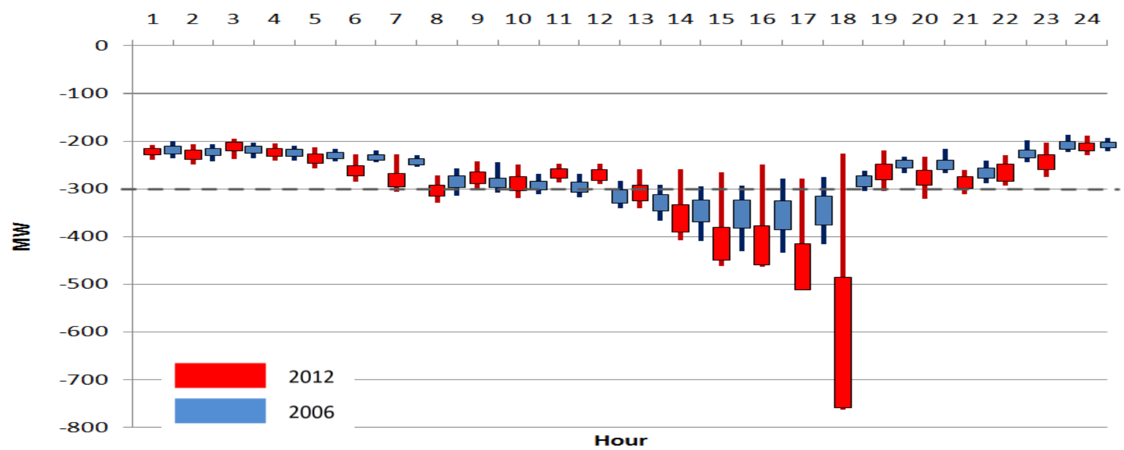


Figure ES-10: Simulated Regulation Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- The simulated percentage change in total regulation capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 37 percent for regulation up and 11 percent for regulation down (as shown in Figure ES-10, most of the regulation down increased requirement is concentrated in three afternoon hours); the results for other seasons are shown in Table ES-1.[14]

- The regulation results require several important clarifications. First, the ISO currently procures 100 percent of its regulation requirement in the day-ahead

[14] The total is defined as the sum of the maximum simulated regulation capacity requirement in each hour of the season; see Section 3 for details.

market, with a minimum requirement in the range of 300 MW in the upwards and downwards direction. First, the simulation does not consider the effect of day-ahead wind and solar production forecast errors on determining the forecast next day regulation need. Second, there are other uncertainties factored into regulation procurement, such as actual uninstructed deviations from dispatch instructions that are not considered in the simulation. Hence, the simulated results shown here may understate the ISO's actual regulation needs, but are indicative of future increases in regulation procurement.

- The additional regulation requirements appear to be well within the capabilities of the existing generation fleet. The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced under 20 percent RPS.

- Moreover, as another indicator of current regulation capability, the 5-minute regulation ramp capability of the generation resources committed and dispatched in each hour of the day since April 1, 2009, has been measured and determined to be above the calculated regulation requirements under 20 percent RPS for most hours.[15] Hence, the empirical analysis suggests that deficiency of regulation capability should not be a problem except in the hours of overgeneration, when regulation down may be in shortage.

Overgeneration Impacts

- The production simulations analyzed both a high hydro year (based on 2006 hydro production) and a low hydro year (based on 2007 hydro production), as well as sensitivities to assumptions about load growth and firm imports, to evaluate their effect on overgeneration. The maximum overgeneration occurred in a scenario that assumed no load growth between 2006 and 2012. The overgeneration in this case was approximately 0.3% (150 GWh) of annual renewable generation.

- Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. In general, overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. There appears to be sufficient dispatchable generation available to operate if the ISO is not prevented from doing so due to an excess of non-dispatchable generation, including imports.

[15] This is a rough measure of how much additional regulation capacity could be procured if units were converted from providing energy or other ancillary services to regulation.

Fleet Operations and Economic Impacts

- The increased supply variability associated with the 20 percent RPS results in the dispatched gas-fired generators starting and stopping more frequently. In an hourly simulation of 2012, combined cycle generator starts increase by 35 percent compared to a reference 2012 case[16] that assumes no new renewable capacity additions beyond 2006 levels. Also, the energy from the combined cycle units reduces by roughly 9 percent on an average, with more reduction occurring during off-peak hours when there wind production is highest, indicating more cycling in the dispatchable fleet.

- The lower capacity factors combined with the reduced energy prices under 20 percent RPS may result in a significant drop in energy market revenues for the gas fleet in all hours of the day and in all seasons. Tables ES-2 to ES-4 show the change in simulated annual energy revenues for three types of gas resources: combined cycle units, simple cycle gas turbines, and gas-fired steam turbines. These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues.

Table ES-2: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table ES-3: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

[16] The only difference between the 2012 reference case and the 20% RPS case is the amount of renewable energy. Both cases use the same load and other assumptions.

Table ES-4: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

Study Recommendations

Based on the study results, the following recommendations are made.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility.** The study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets do not reveal that full capability due to self-scheduling. In particular, the empirical analysis demonstrated the shortage of the 5-minute load-following capability in the downward direction when resources are self-scheduled, as compared to offering their actual physical capabilities for economic dispatch. These results were further substantiated using production simulation. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfalls in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: (a) Develop a regulation prediction tool.** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a tool to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance market efficiency.

- **Improve day-ahead and real-time forecasting of operational needs: (b) Develop a ramp/load-following requirement prediction tool.** The ISO should accelerate the development of improved forecasting of operational ramps generally and load-following requirements on different intra-hourly time frames. This capability could be complemented by evaluation of whether to modify unit commitment algorithms and procedures to reflect those forecast ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact from changes in procurement and prices for wholesale energy and ancillary services as well as the implications for payments through resource adequacy contracts.

1 Introduction

California's existing Renewables Portfolio Standard (RPS) requires utilities to achieve their statutory obligation to supply 20 percent of all consumed electricity from eligible renewable resources by 2010. Compliance with this level is now anticipated in the 2011-2012 timeframe and will likely depend on load growth, contract implementation, and other factors.[17] The California Independent System Operator Corporation (ISO), along with the California state agencies and the electric power industry, is conducting the substantial planning, along with the operational, technological and market changes, needed in the power sector to accommodate this higher level of renewables.

The majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies.[18] The key operational characteristics of such resources are the variability of their generation over different operational time-frames (seconds, minutes, hours) and the uncertainty associated with forecasting their production (i.e., forecast error). As such, the integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

The ISO provides open access to the transmission system under its control while simultaneously operating the grid and markets for energy, ancillary services and

[17] California Public Utilities Code Section 399 requires that the RPS objectives be achieved by 2010, with some accommodation for deferred compliance under specified circumstances. In 2009, the California investor-owned utilities served 15.4 percent of their load with renewable energy eligible under the RPS. In late 2009, the California Public Utilities Commission (CPUC) estimated that the 2010 deadline would not be met and that 2013-14 was more realistic. However, in mid-2010, based on declines in electricity consumption, rapid growth in RPS contract approvals (including short-term contracts for out-of-state wind energy), and other factors, the CPUC estimated that the 20 percent target could be reached in 2011. In this study, the ISO models 20 percent renewable energy in 2012. See CPUC, Renewables Portfolio Standard, Quarterly Report (Q4 2009), at p.4, and CPUC, Renewables Portfolio Standard, Quarterly Report (2nd Quarter 2010), at p. 3, both available at http://www.cpuc.ca.gov/PUC/energy/Renewables/documents.htm.

[18] "Variable energy resources" is the term being used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is thus used here as an equivalent term to "intermittent resources". Not all renewable resources eligible under renewable portfolio standards are variable energy resources. For example, geothermal, biogas and biomass resources generally follow fixed hourly schedules.

congestion revenue rights. The design of the ISO's integrated wholesale market and system operations has the capability to significantly facilitate renewable integration. There are both day-ahead and real-time markets that optimize the utilization of system resources using state-of-the-art software, while accounting for key constraints on electric power production such as generation unit operating characteristics and transmission congestion and losses. During the operating day, the ISO now has more accurate procedures to adjust market resources in response to changing real-time conditions, with dispatch instructions sent every five minutes. This allows for more efficient use of system resources in following the output of variable energy resources, like wind and solar. As a result, the redesigned market will allow more renewable energy to be integrated into the system.

As the entity with primary responsibility for the continued reliable operation of the electric transmission, the ISO needs to evaluate the effects on system and market operations of integrating 20 percent RPS. If necessary, the ISO will take action to facilitate renewable integration and address any adverse effects on market functioning and reliability. In this regard, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study in 2007 focused on the operational and transmission requirements of wind integration ("2007 Report").[19] This report builds on those efforts. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

1.1 Report Organization

The report is organized as follows. The remainder of this section provides background on the impacts of generation from variable energy resources on operations and market functions and identifies the specific objectives of this study. Section 1.2 reviews the mix of resources projected to fulfill California RPS requirements by 2012. Section 1.3 discusses the characteristics of generation from variable energy resources and how they impact system operations. Section 1.4 sets forth the specific objectives of this study and also discusses how this study builds upon prior work.

Section 2 then provides an overview of the simulation methodologies and the scenarios that were modeled in this study. Section 3 discusses the results of the simulations that were used to determine the operational requirements, i.e., regulation and load-following requirements, under 20 percent RPS. Section 4 describes the results of the empirical analysis performed to assess the historical capability of the fleet and how it compares

[19] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007) at http://www.caiso.com/1ca5/1ca5a7a026270.pdf. Another recent report on renewable integration using ISO data by KEMA titled, "*Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid* (June 2010)" can be found at http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

with the future operational requirements. Section 5 presents the results of the production simulations used to test the capability of the fleet to meet the operational requirements with and without the 20 percent RPS in 2012. Finally, Section 6 provides recommendations.

Similar to the 2007 Report, this report includes a set of appendices that provide additional results and selected discussion of methodology. There is also a separate technical appendix that provides mathematical formulations of the models and other information on how renewable production profiles and forecast errors were developed.

1.2 California Renewable Portfolio Standards

After several years of fairly static energy production from renewable resources, the next few years could see a significant increase in production each year, with the great majority from variable energy resources. In 2009, California investor-owned utilities collectively served 15.4 percent of their load with renewable energy. In late 2009, the California Public Utilities Commission (CPUC) forecast that 20 percent RPS would be achieved by 2013-2014. More recently, the CPUC estimates that utilities are expected to have procured approximately 18 percent renewable energy in 2010 and over 20 percent by 2011 based on signed renewable resource contracts.[20]

Much of the incremental renewable deliveries anticipated over the next couple of years to achieve the RPS target will be from operational out-of-state resources, many of which have signed short-term contracts with California utilities. Under current scheduling practices, the Balancing Area Authority (BAA) exporting the renewable energy to California will be largely responsible for managing the variability and uncertainty of the renewable resources interconnected to its system. This has the potential to mitigate the integration requirements confronting the ISO in the near-term. However, as those short-term out-of-state contracts expire, they will generally be replaced by power purchase agreements with in-state renewable resources.[21] Existing out-of-state resources may also seek dynamic transfer arrangements with the ISO. Both of these circumstances will shift the integration requirements to the ISO.

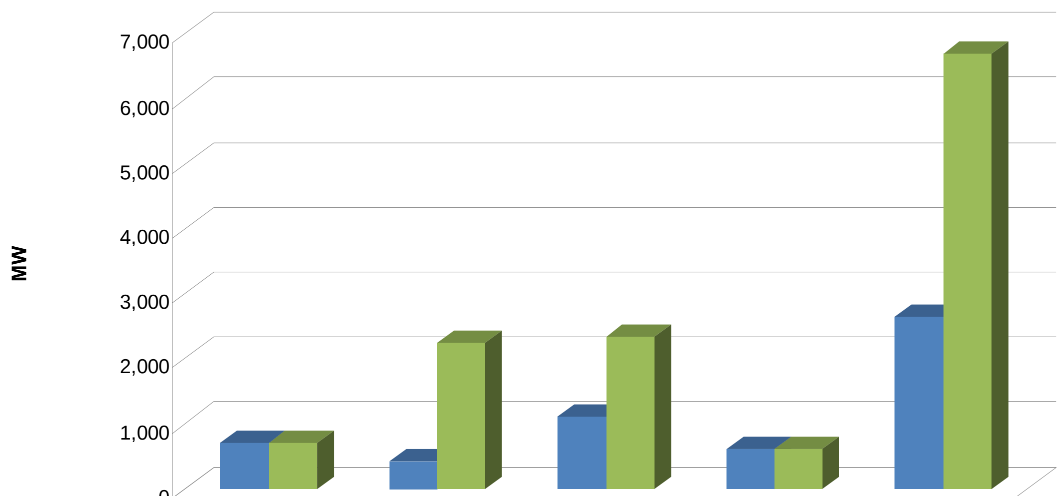
This study assumes that most of the renewable generation is in-state and within the ISO BAA – or equivalently that a high proportion of the in-state and out-of-state resources located outside the ISO BAA are dynamically transferred into the ISO. Such an assumption is not only consistent with the longer-term trend of the utility contracts, but also comports with the ISO's objective in this study to test the capability of the existing fleet to provide the integration requirements within the ISO BAA at 20 percent RPS.

The renewable resource portfolio includes a wind resource forecast developed by the ISO and consultants, and adapts a forecast of expected solar and geothermal capacity

[20] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[21] For information on the status of RPS procurement activity by California's investor-owned utilities see the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Renewables.

developed by the CPUC in 2009.[22] The renewable resource capacity (MW) and associated expected energy production (MWh) were adjusted, based on 2012 load forecasts, to provide approximately 20 percent energy from RPS-eligible resources. Figure 1-1 shows the renewable capacity modeled. The figure also shows the renewable generation portfolio modeled in the base-year of the study (2006). The year 2006 was chosen as the base year to facilitate easier comparison with the 2007 Report. Compared to the 2007 Report, this study evaluates an additional 1,826 MW of solar generation, comprised of 830 MW of solar photovoltaic (PV) and 996 MW of solar thermal resources, for a total of 2,246 MW of solar resources. Both the 2007 Report and this study assume 6,686 MW of wind resources by 2012.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure 1-1: Renewable Resources in the Base Case and under 20 percent RPS scenarios

1.3 Potential Impacts in System Operations

As noted above, the majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies. This section discusses the impact of the generation variability and forecast uncertainty on power system operations.

[22] The portfolio was the CPUC 20 percent RPS reference case developed for its 33 percent RPS Implementation Analysis. See http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

1.3.1 Variability of Wind and Solar Generation

The variability of wind and solar generation is measured over different time-scales. Beginning on the time-scale of minutes, Figure 1-2 shows the variability in wind and solar PV generation on a minute-by-minute basis over the full day. Figure 1-3 then shows those variations more closely on a sub-hourly basis. The implications for system operations are that, unless the variability is smoothed by the variable energy resource itself, other resources have to increment or decrement their generation on similar time frames (seconds, minutes, hours) to compensate for the supply variability. The ISO operational time frames and procedures by which this is done are discussed in the next section.

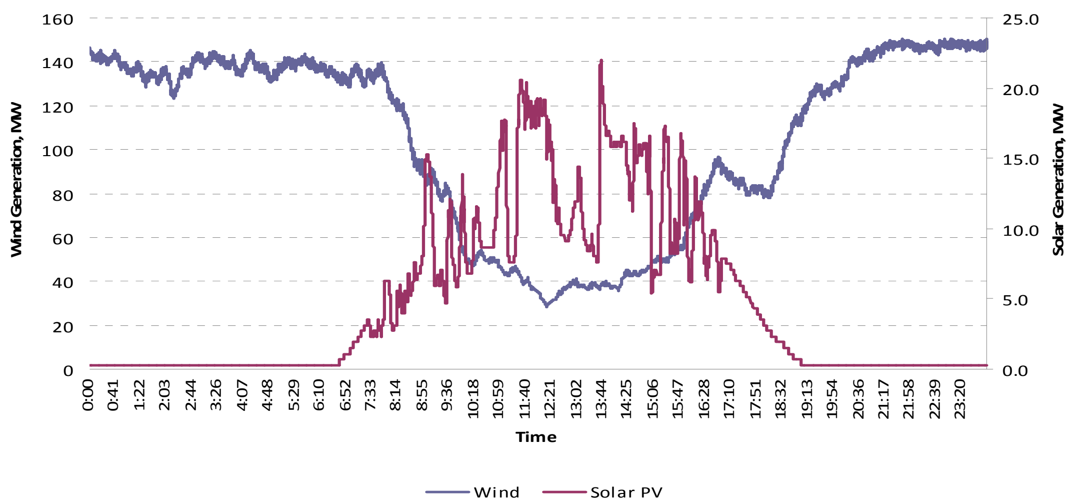


Figure 1-2: Sub-hourly wind and solar generation for a day for a 150 MW wind generator and a 24 MW Solar PV plant

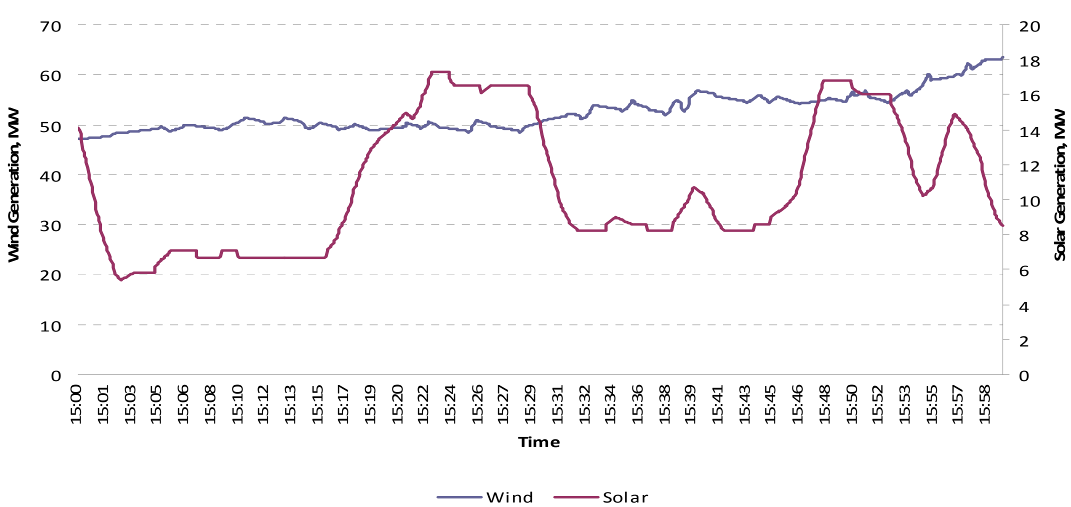


Figure 1-3: Sub-hourly wind and solar generation profiles for an hour

On any particular day, the multi-hour ramps associated with wind production, and the range of that production, can vary significantly. Figures 1-4 to 1-7 illustrate simulated high ramp days in every season in 2012 based on data on historical wind performance in California, in which total state-wide wind production can vary from almost full output to very low output in a few hours, and vice-versa. The simulated load and renewable energy production shown in these and subsequent figures are based on assumptions, data and methods described in Section 3.

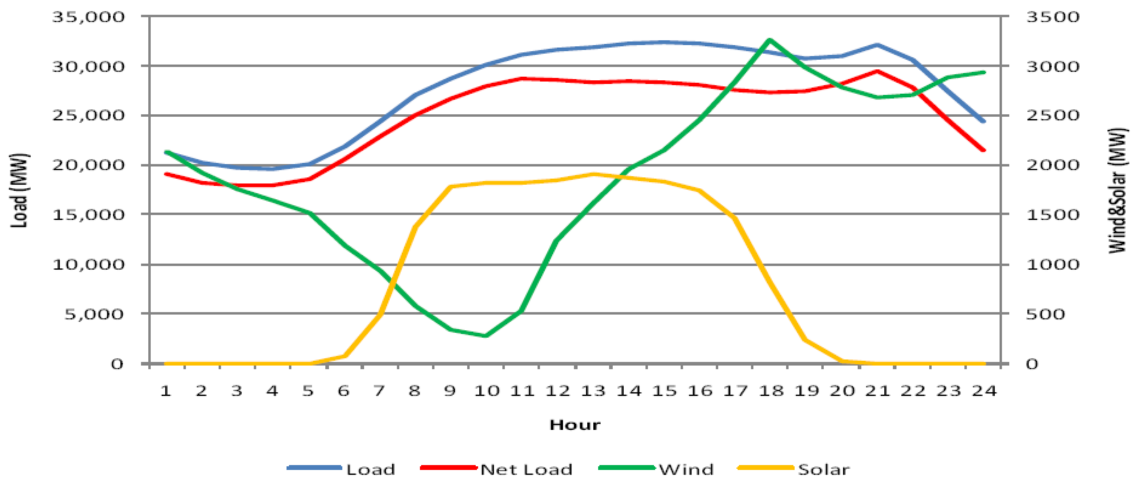


Figure 1-4: Simulated May 8, 2012

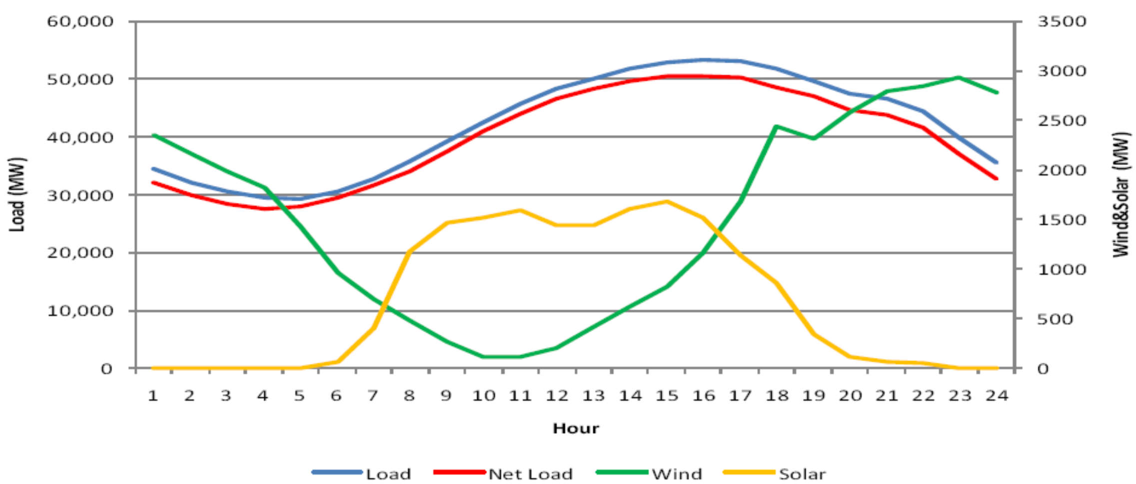


Figure 1-5: Simulated July 25, 2012

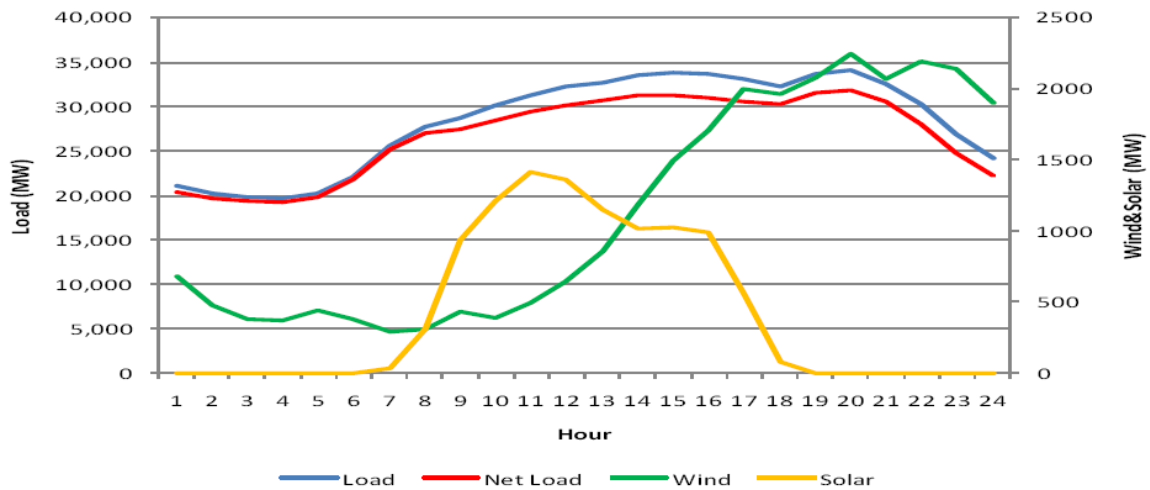


Figure 1-6: Simulated October 23, 2012

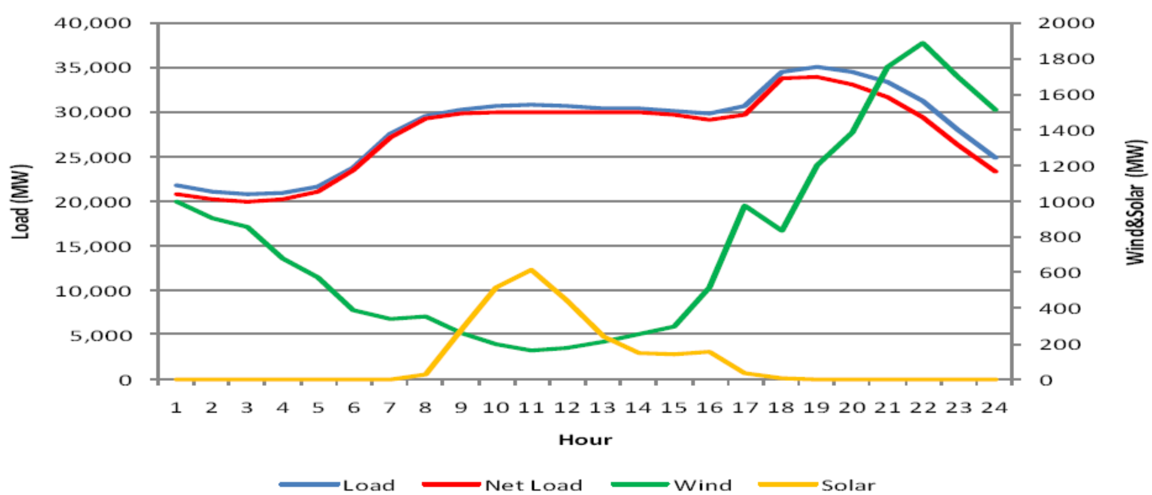


Figure 1-7: Simulated December 4, 2012

On the time-scale of multiple days, wind production will vary substantially across each day, regardless of the season. Figure 1-8 shows the daily wind pattern for May 2012 analyzed in this study. Each line of a different color represents a different day in the month. The monthly average hourly production shown by the thicker red line thus represents a wide range of actual daily production. Figures 1-9 to 1-12 show the dispersion of simulated wind production by operating hour in each season in 2012. These figures show that in almost every operating hour, wind could be producing across the full range of its potential production, from close to zero to almost maximum output.

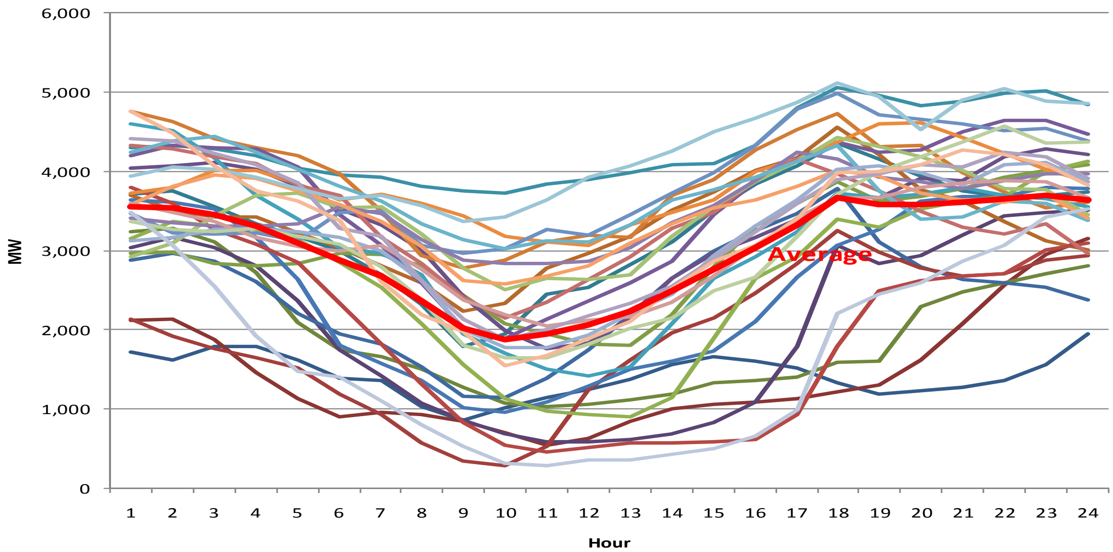


Figure 1-8: Wind Production in May 2012 based on 2005 production patterns

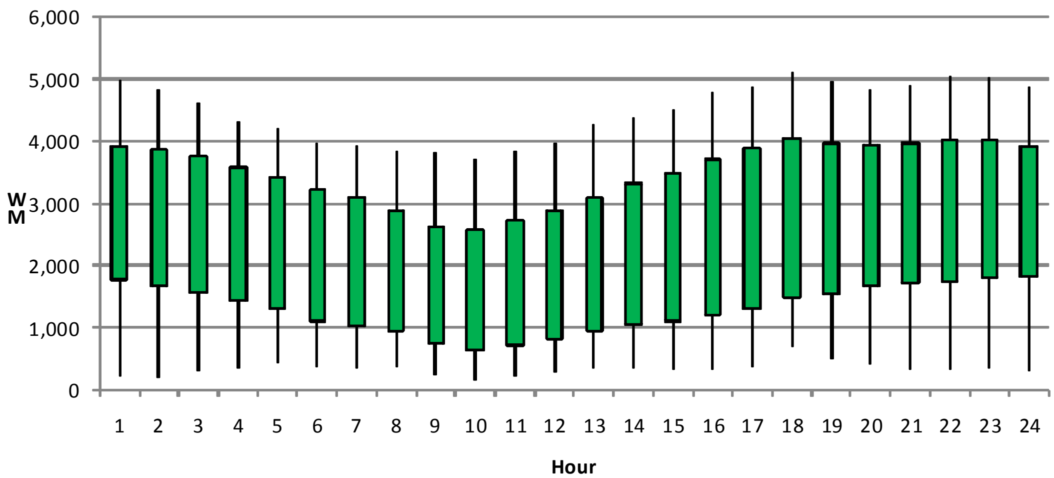


Figure 1-9: Spring 2012 Simulated Wind Production by Hour

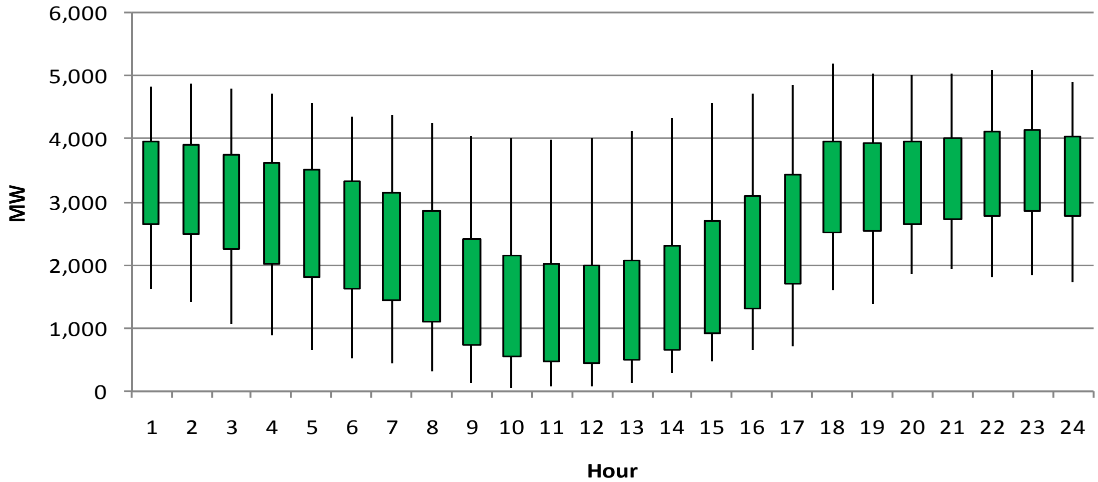


Figure 1-10: Summer 2012 Simulated Wind Production by Hour

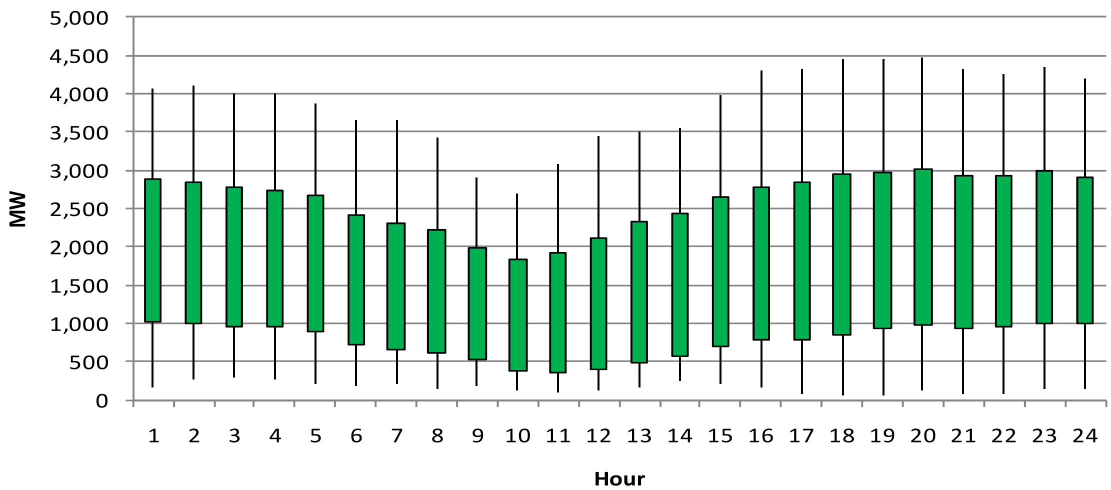


Figure 1-11: Fall 2012 Simulated Wind Production by Hour

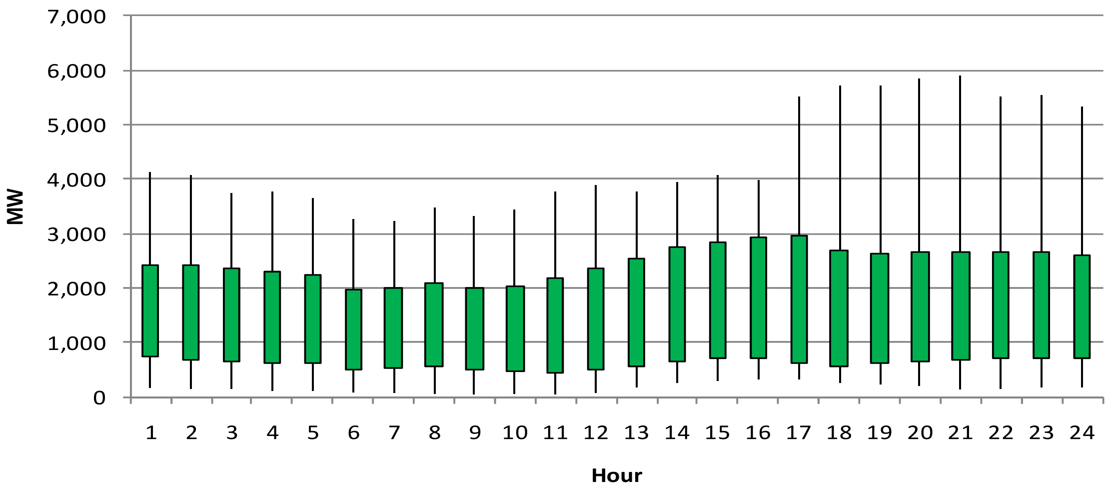


Figure 1-12: Winter 2012 Simulated Wind Production by Hour

Another important characteristic of wind generation is that it may operate at low capacity during peak hours, particularly the annual summer peak demands. Figure 1-13 shows wind generation production during the historical peak hours in the July 2006 heat wave. The red dots indicate peak hours, showing that average hourly production during those hours was close to the daily minimum wind production. Of note, 2006 is one of the benchmark years for the simulations in this study. In other years, there will be different patterns of summer peak hour wind energy production. For example, Figure 1-14 shows that in July 2010, wind production was higher during peak hours than in 2006, but still below maximum production, while Figure 1-15 shows that in August 2010, peak load production varied substantially.

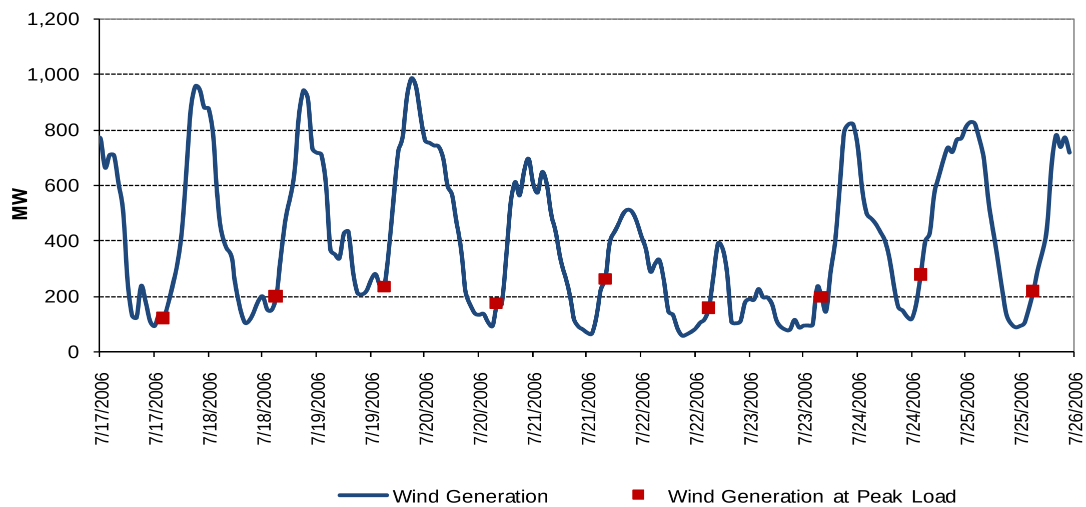


Figure 1-13: Wind Production during Summer Peak Hours in 2006

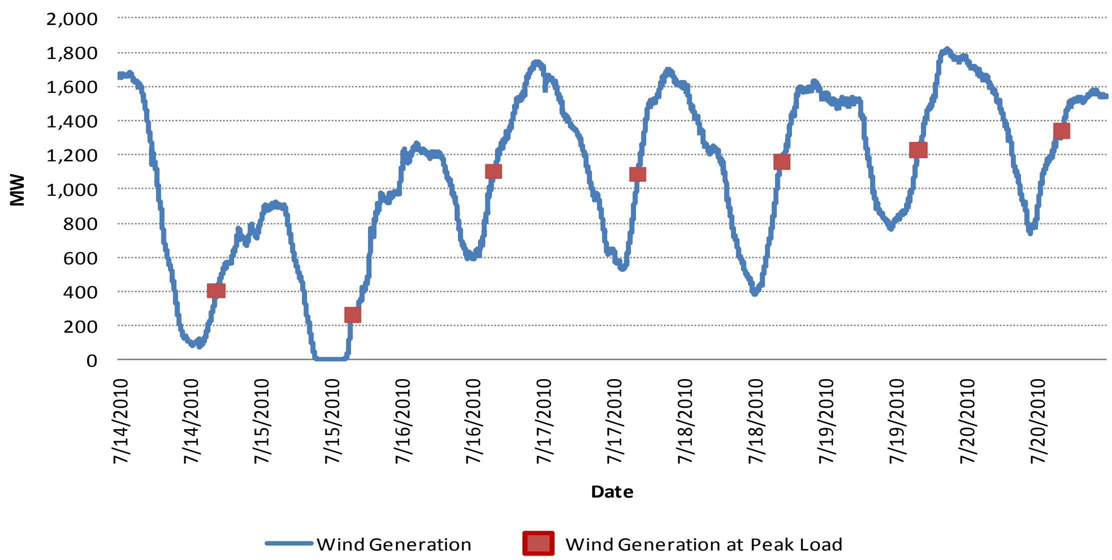


Figure 1-14: Wind Production during July Peak Hours in 2010

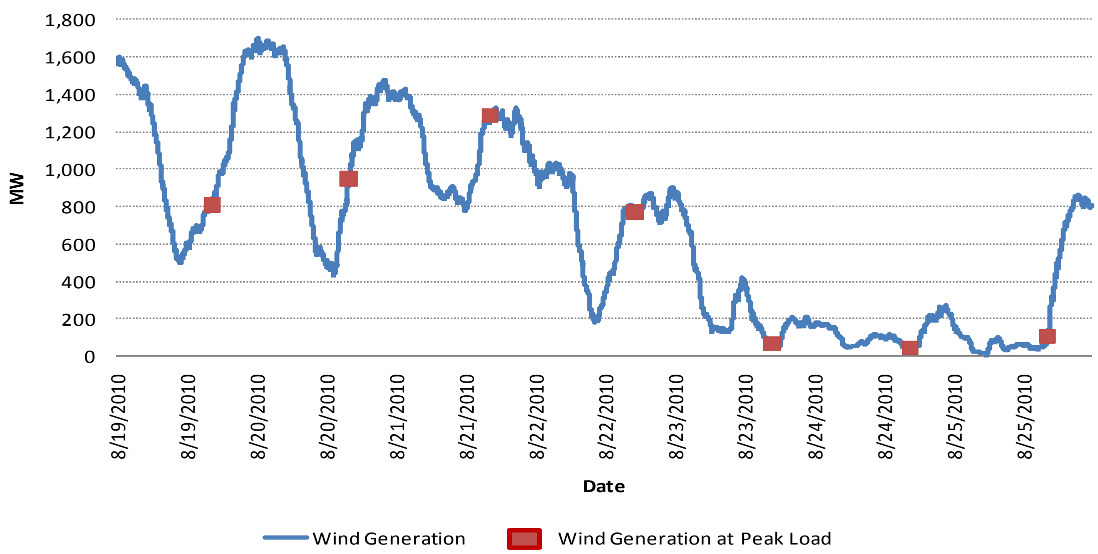


Figure 1-15: Wind Production during August Peak Hours in 2010

Even on the time-scale of months or seasons, when average production is measured, total wind generation can vary fairly substantially by hour and season. For much of the year, wind generation is on average inversely related to load, but in some seasons, notably spring, there can be a higher correlation on average between peak wind production and peak daily load.[23] Within any particular season, as noted above, the average wind

[23] As shown in Figure 2-1, in the spring months, the total wind generation on average starts decreasing after midnight and reaches its minimum production level around midday, just as the system experiences the first peak of the day. Beginning around Hour 13, the wind generation starts to increase while system load

production shown here does not reflect the significant differences in wind production on any particular day. Solar production is clearly well correlated with the daily load cycle, but seasonal weather patterns can result in different average solar generation. Moreover, in the winter, solar production can diminish before the daily peak hours.

1.3.2 Wind and Solar Forecast Uncertainty

The second important operational characteristic of variable energy resources is the uncertainty about their production, due to the current accuracy of weather forecasting, in particular of wind speed and cloud formations. Historically, given its variable nature, wind generation has been taken on an as-available (or "must take") basis, and grid operators compensate by incrementing or decrementing the output of other committed generation. At low wind penetrations, such actions do not significantly affect system operations. At higher levels of wind penetration, however, forecast uncertainty becomes more challenging. Figure 1-16 shows actual wind generation and the forecasted wind generation in the hour-ahead time frame.

Improvements in forecasts will facilitate renewable integration by allowing operators to ensure that the right resources are committed and on dispatch to address actual variability. The ISO is undertaking a number of initiatives to improve forecasting and the integration of forecasts into its market and system procedures.[24] This study does not focus on improvements in forecasts, but does conduct sensitivity analysis in the simulations to examine the impact of such improvements on operational requirements (see Appendix A-2).

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typically drops off. As system load increases towards the second peak of the day (which occurs in the spring), the pick-up in wind generation offsets some of the energy required to meet the increase in load. As system load begins dropping after the daily peak, wind is typically at its highest generation level. In the summer and fall months, average wind production peaks around Hour 24 and then decreases over the morning until reaching a minimum in the middle hours of the day, when load is at or close to its maximum. Wind production picks up in the early evening hours when load is typically decreasing. The winter months have a slightly different average pattern, in which average wind production is less variable over the day.

[24] The ISO aims to achieve continuous improvements as they become available by both public and commercial weather forecasting systems as well as innovative technology vendors (such as laser-based short-term wind forecast technologies). In this regard, during 2008-09, the ISO undertook an evaluation of three commercial wind forecasters that demonstrated improvements in both day-ahead and hour-ahead forecasts and examined the impact on wind forecast errors of geographic diversity of wind resources and different load levels, among other factors. The results are available in California ISO, *Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance*, March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf.

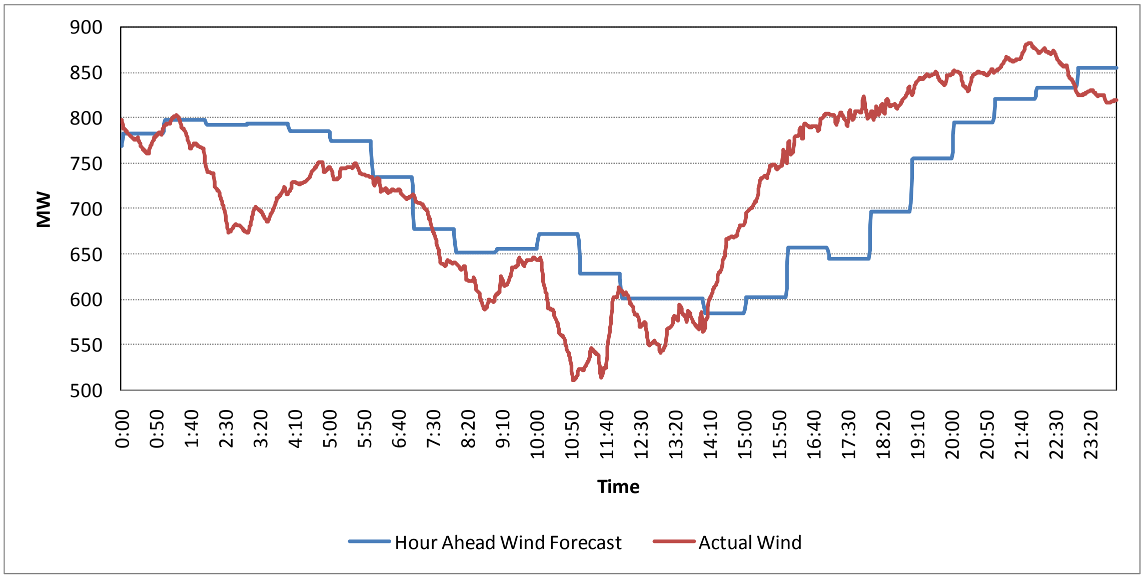

Figure 1-16: Hour-ahead forecast and actual generation profile for wind production, June 24, 2010

1.3.3 Impact of Variability and Uncertainty on Market and System Operations

Variable energy resources schedule and operate within the sequence of day-ahead to real-time market and system operational procedures that the ISO conducts on various intervals over the day. The ISO markets are a specialized type of wholesale commodity market in that any scheduling and trading must be consistent with: (a) the physical laws that govern power flows, (b) the need to balance the system second-by-second, and (c) physical and reliability constraints that affect the operation of both generation and transmission facilities—particularly the congestion and losses associated with transmission use. The ISO markets are in fact designed around reliable system operations, and the prices generated in those markets provide information relevant to future operational needs. More information on the markets and system operations can be found in the ISO's business practice manuals (BPMs), tariff, and other technical documents; this section focuses on a few key features applicable to renewable integration.[25]

Because generation resources have different start-up times (ranging from more than 24 hours for large steam units to under 10 minutes for gas turbines), system operators must begin the process of scheduling generation based on forecasts of next day system conditions. This is the function of the ISO day-ahead market, which takes place in the

[25] On market and system operations, see in particular the BPM for market instruments and the BPM for market operations. These are available at http://www.caiso.com/17ba/17baa8bc1ce20.html. More detail on the ISO's market and system operations and renewable integration can be found in the ISO's comments to the Federal Energy Regulatory Commission (FERC) in its recent notice of inquiry on variable energy resources, available here: http://www.caiso.com/2777/2777ac8636f20.pdf. In addition, the ISO will be undertaking a detailed review of market design changes needed to facilitate renewable integration, with documents and schedules provided here: http://www.caiso.com/27be/27beb7931d800.html.

afternoon of the day prior to the operating day. The day-ahead market consists of an integrated forward market that clears on the basis of schedules and market bids submitted by both suppliers and load. The integrated forward market is also where the ISO aims to procure one hundred percent of its ancillary service requirements for the next day, including regulation, spinning reserves and non-spinning reserves.[26] The ISO then makes adjustments to the day-ahead schedule using its own load forecasts and forecasts of renewable production in a process called the residual unit commitment. This sequence of markets and procedures is collectively called the day-ahead market.

Wind and solar resources can schedule voluntarily in the day-ahead market. However, there is currently little incentive for them to do so prior to the hour-ahead scheduling process, as discussed next. Moreover, day-ahead forecast errors for variable energy resources are not insignificant. From an operational perspective, the failure to schedule renewable resources day-ahead can result in additional commitment of conventional resources. In the event that the day-ahead market significantly underestimates the next day's renewable production, there could be situations in which the ISO has difficulty committing the right conventional units to provide integration capabilities in real-time.[27] The simulations described in Section 3 and Section 5 attempt to test for this outcome.

The day-ahead market schedules are in one-hour blocks; that is, there are no schedules for expected load or wind and solar production at intervals within the hour. When the operating day begins, the real-time market serves to adjust day-ahead schedules to account for imbalances, because of forecast error, changes in system conditions, actual intra-hourly load and renewable energy production, and any other factors. It does so through a sequence of procedures, including an hour-ahead scheduling process for changes to intertie schedules, rolling intra-hourly unit commitment procedures, and 5-minute economic dispatch intervals in which system operators send instructions to increment or decrement the output of generators under dispatch.

Scheduling of wind and solar resources under the ISO's Participating Intermittent Resource Program (PIRP) is conducted through a special process. Prior to the hour-

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[26] Ancillary services are additional services provided by generation and, increasingly, non-generation resources, such as demand response and storage, that are needed for power system reliability. As discussed elsewhere in this report, ancillary service procurement may increase with additional renewables. Two types of ancillary services are procured by the ISO through the wholesale markets: operating reserves and regulation. Operating reserves are essentially capacity retained on generators that can be converted to energy in a short period of time in order to responds to contingencies such as the loss of a generating resource or a transmission line. There are two types of operating reserves in the ISO markets: ten-minute spinning reserves, provided by resources that are synchronized to the grid, and ten-minute non-spinning reserves, provided by resources that are not synchronized but can start and provide energy within ten minutes. Regulation is energy provided on a second-by-second basis for system balancing by resources equipped with automatic controls. Currently provided by thermal generators and hydro systems, regulation could be supplied also by demand response and storage technologies. The ISO also meets other ancillary services requirements that are not procured through the markets, such as voltage support and black-start.

[27] If the integrated forward market fails to forecast renewable energy production adequately, the ISO can also adjust its residual unit commitment to account for forecast renewable production. However, as this residual unit commitment takes place day-ahead, it is also subject to forecast errors.

ahead scheduling process, data is collected from wind resources and transferred to a forecast service provider, which develops an hour-ahead wind forecast. This forecast is then returned to the ISO via the scheduling coordinators for the participating resources. Deviations from the hour-ahead schedules are followed by the ISO's dispatch functions (every five minutes) and regulation (second-by-second) in real-time. Resources in the PIRP are settled financially using a formula that nets their imbalances over the month and applies an averaged monthly locational marginal price for energy. Generally, because of their contracts, production incentives, and technology, wind and solar resources do not respond to price-based dispatch instructions, but only to reliability-based dispatches when they are needed to decrement output to address congestion or overgeneration. If such resources become more price-responsive, they could reduce the ISO's need for additional operational capabilities discussed in this report.

1.3.3.1 Impact on Load-following and Regulation

To further explore the operational and market impact of variability and forecast uncertainty in real-time requires additional detail on how the ISO markets follow load and renewable resource schedule deviations over the operating hour. Secondary frequency control mechanisms such as load-following and regulation are the key mechanisms by which the ISO maintains the balance between generation and load in the time frame of seconds to minutes.

The demand and generation are constantly changing within the ISO balancing authority area (BAA). This means that the ISO will have some unintentional outflow or inflow of energy at any given instant. The mismatch in meeting a balancing authority's internal obligations, along with a small obligation to maintain frequency, is measured via an instantaneous value called Area Control Error (ACE), measured in MW. The North American Electric Reliability Corporation (NERC) control performance standards are intended to be the indicator of sufficiency of secondary control. Overgeneration makes ACE go positive and the frequency increases. A large negative ACE causes frequency to drop. NERC Control Performance Standards (CPS1 and CPS2) capture these relationships. In simple terms, CPS1 assigns each balancing area a slice of the responsibility for control of the interconnection frequency. The amount of responsibility is directly related to the size of the BAA. CPS2 is a statistical measure of ACE over all 10-minute periods in a month. Under CPS2, ACE is limited to a regulating range whose width is proportional to the BAA's size.

The ISO monitors ACE and attempts to keep the value within specified limits. This is accomplished through a combination of automatic generator adjustments, manual dispatch and sales and purchases from neighboring balancing authorities. The ISO maintains sufficient generating capacity, both in the up and down direction, under automatic generation control (AGC) within the energy management systems (EMS) to continuously balance generation and interchange schedules with real time load.[28] Although the regulation dispatch is done every four seconds, the regulation margin has to

[28] The WECC defines AGC as equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

be adequate to meet deviations within a 5-minute dispatch interval. The capacity under AGC is referred to as regulating reserve or regulation.[29] Figure 1-17 pictorially depicts the regulation capacity requirement—that is, the MW range that regulating resources must be able to provide—as the area shaded in red: the area between actual load and the 5-minute dispatch.

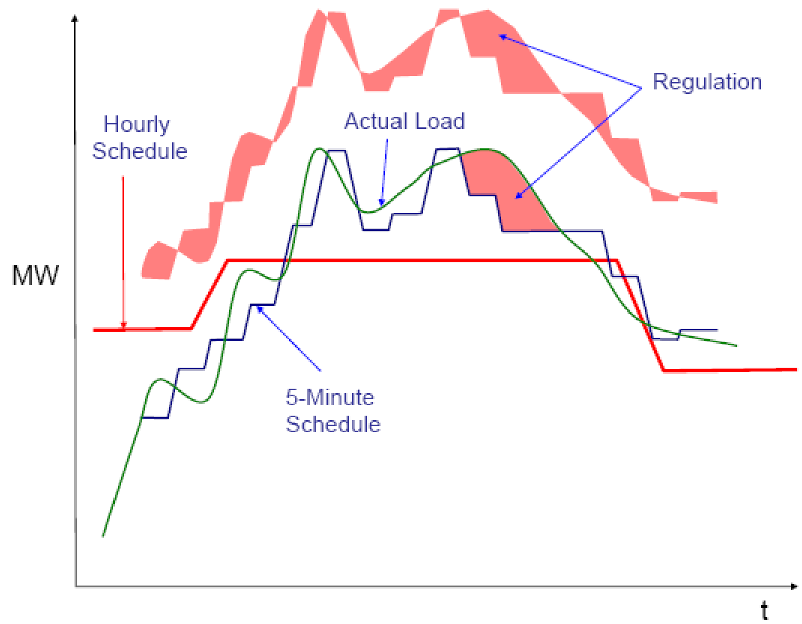

Figure 1-17: Regulation Requirement shown as the red shaded area

Load-following is the use of online generation on economic dispatch or quick start generation to meet the intra- and inter-hour changes in loads. While regulation is needed to balance the minute-by-minute changes in the system and keep ACE with limits, load-following is required to ensure that the system has enough capacity on economic dispatch to move from one 5-minute dispatch interval to the next. Load-following is not an ancillary service like regulation and is not explicitly procured by the ISO in its day-ahead and real-time markets; rather, it is a function of the generation committed and dispatched in the day-ahead to real-time market and operational sequence and is met as long as the optimization algorithms used in those processes are appropriately specified. Similar to regulation, load-following is defined in both the up and down directions.

In this study, several measures of load-following requirements are presented, including capacity and ramps over various time frames needed to fill the gap between the difference between the day-ahead hourly schedule for an operating hour and the real-time 5-minute dispatch schedule. In Figure 1-18, load-following capacity—that is, the incremental and decremental energy that resources on economic dispatch have to be able to provide

[29] The WECC defines Regulating Reserve as sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

within the operating hour to meet load—is depicted graphically as the blue shaded area. Load-following ramp rate, expressed in MW/min, is the rate at which this capacity can ramp from one 5-minute dispatch point to the next.

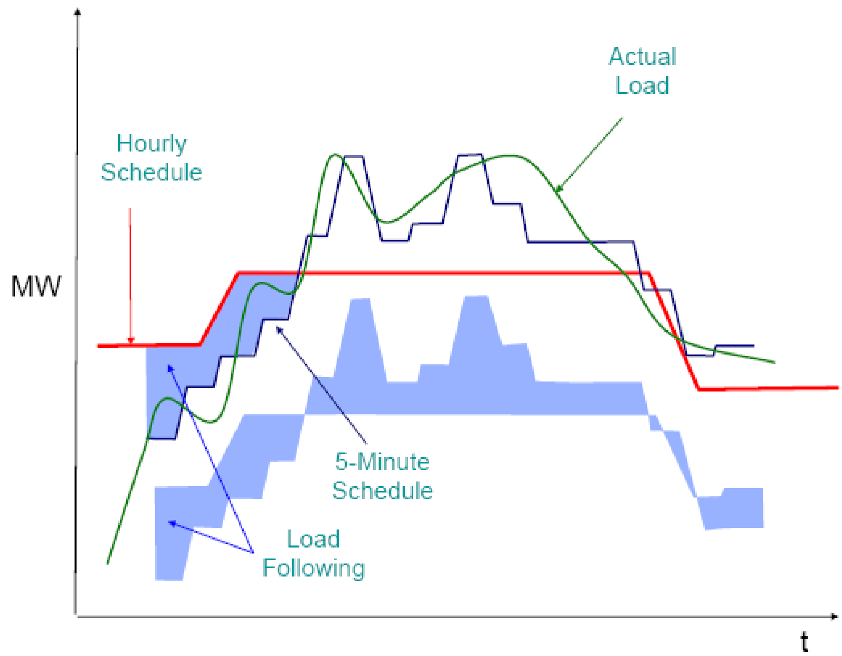

Figure 1-18: Depiction of hourly load-following capacity requirement

As seen in Figure 1-2 and Figure 1-3, wind and solar generation vary on a minute-by-minute basis. The variability in wind and solar generation, coupled with the variability in load, will have an impact both on regulation and load-following requirements. The uncertainty in wind and solar generation increases the system operator's need to reserve capacity for wider ranges of regulation and load-following capability than would otherwise be needed if they had full certainty about the actual variability. Uncertainty in the day-ahead timeframe may lead to a unit commitment with inadequate regulation and load-following capability that is required in real-time. The lack of regulation and load-following capability may have an impact on ACE, and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require the curtailment of generation to keep ACE within specified limits.

1.3.4 Overgeneration due to Variable Energy Resources

Overgeneration occurs whenever there is more generation than load and the operators cannot move generators to a lower level of production. In California, overgeneration is most likely to occur under the confluence of some or all of the following conditions: light spring load conditions (historically with loads around 22,000 MW or less), all the nuclear plants on-line and at maximum production, hydro generation at high production levels due to snow melt in the mountains, long-start thermal units on-line and operating at their minimum levels because they are required for future operating hours, other generation in a regulatory "must take" status or required to be on-line for local reliability reasons, and wind generation at high production levels. At higher levels of RPS, solar production may also be a factor in overgeneration conditions, particularly in the morning solar ramp hours.

All other things equal, the increased generation from variable energy resources under a 20 percent RPS is expected to lead to higher frequency and magnitude of overgeneration conditions than exist today. Even if renewable resources were perfectly predictable and constant (i.e., no uncertainty and variability in generation), the amount of wind and solar generation that can be accommodated into the system will depend on the extent to which the existing fleet can be dispatched downwards to accommodate the renewable energy. Inability to dispatch the existing fleet will lead to overgeneration conditions and could possibly result in the curtailment of renewable generation.

To illustrate overgeneration conditions, Figure 1-19 shows the load for one week (red trace) and the generation from non-dispatchable resources. Non-dispatchable resources in this figure include the following generation resources: nuclear, biomass, geothermal, Qualifying Facilities (QFs), hydro and imports. Non-dispatchable resources also include wind and solar generation. Some of the resources are dispatchable, but a portion of their generation is treated as fixed due to contractual and other reasons. During some periods, the total generation from the non-dispatchable resources approaches the load that needs to be served. These periods will likely see overgeneration, especially if thermal generation needs to be dispatched at their minimum operating level. Importantly, overgeneration in this case has very little to do with the variability and uncertainty of generation from variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

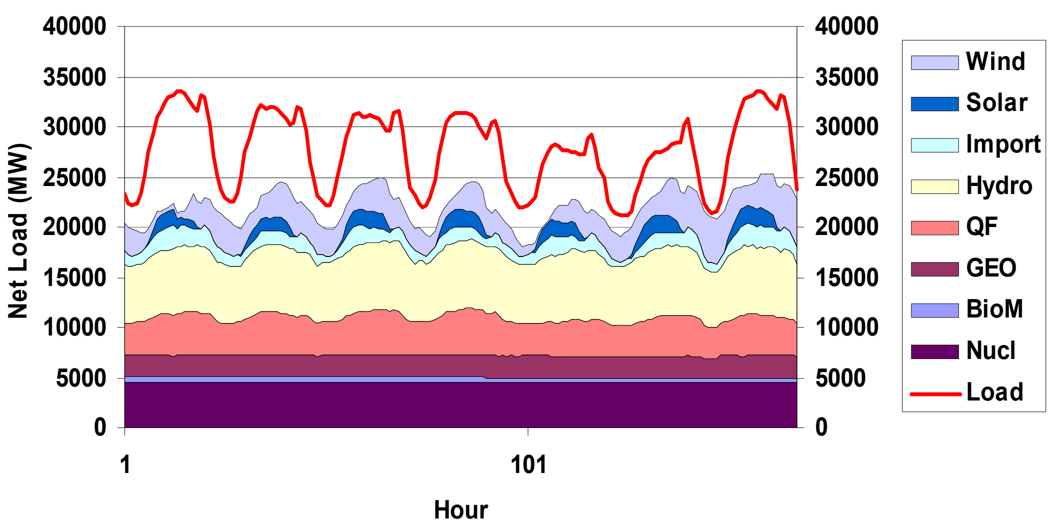

Figure 1-19: Load and Non-dispatchable generation for one week

1.4 Objectives of this Study

The ISO and California state agencies have undertaken several analyses that attempt to estimate the requirements on the power system to integrate higher levels of variable energy resources, including the ISO's 2007 Report.[30] The 2007 Report concluded provisionally that integrating 20 percent renewable energy into the California electric power system is operationally feasible, subject to changes to operating practices. Based on a high-level survey of existing resources, the report also concluded that ISO generation and pumped storage was adequately flexible to meet the anticipated ramping requirements for load-following and regulation. The report noted the potential for renewable energy to cause an increase in overgeneration conditions, but did not attempt to quantify that increase.

This study addresses some of the recommendations of the 2007 Report and fills some of the gaps in the prior analysis. Because that report focused only on the impact of wind generation on system operations, one of its recommendations was for a future study to analyze the impact on integration requirements of solar power variability and forecast error. Another recommendation was to study changes in the commitment and dispatch of thermal resources due to renewable integration, in particular to quantify the impact of additional cycling (additional start-ups) and associated wear-and tear on conventional generation. This study addresses these recommendations and undertakes other analysis. Other recommendations are being addressed through various other ISO operational and market initiatives.

The starting point for the present analysis is that while there is substantial interest in storage and demand response to provide integration capabilities, at least during the next few years, support for integration of renewable resources during normal operating conditions will need to be provided largely through the flexibility of existing, re-powered, and new thermal generation. This generation fleet will also need to have the ability to provide sufficient ancillary services, particularly regulation up and regulation down and possibly some additional operating reserves.

Given this background, this study focuses on the operational requirements and assessment of generation fleet capability, along with measurement of generator operations and economic impacts, under the most recent estimate of the conventional and renewable resource mix under a 20 percent RPS. The core objectives of the present study are:

- to forecast the operational requirements and extreme conditions—specifically operational ramps, load-following, regulation, and overgeneration—under a 20 percent RPS that includes over 2000 MW of solar;

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30 California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid*; KEMA, *Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid*.

- to further assess and verify—through analysis of historical operational data, as well as simulations of future conditions—that the existing fleet is sufficiently capable of satisfying the forecasted system operational requirements; and

- to provide insight on expected changes to generation fleet operations and market revenues.

The analysis and conclusions presented here will be augmented by the ISO's forthcoming scenario-based 33 percent RPS operational and market study, which is similar in structure and methodology to this study. As the renewable portfolios in 2020 and interim years become better defined, the ISO will also extend this analysis to renewable cases between 20 percent and 33 percent RPS.

2 Study Methodology and Assumptions

To provide the level of detail on operational requirements and capabilities needed to enable adequate system and market preparations, the ISO has worked intensively, including through collaboration with a number of organizations, to develop a suite of simulation models and to conduct extensive analysis of empirical data. A further objective is to standardize elements of these analyses to support periodic updating of the results as the mix and location of future renewable resource portfolios changes. This study utilizes several of these analytical methods to assess both the operational requirements associated with renewable integration and the capability of the generation fleet to meet those requirements.

The study evaluates a subset of key *operational requirements* that include (1) operational ramp rates at different time scales, (2) regulation capacity and ramp rate, and (3) load-following up and down capacity and ramp rates. These requirements are estimated using a statistical simulation methodology initially developed for the ISO's 2007 Report; for this study, that methodology has been updated to evaluate the impact of solar production forecast error and variability on these requirements.

Operational capability refers to the ability of the ISO's existing and planned generation and non-generation resources to address the incremental operational requirements as a result of variable energy resources. For this study, operational capabilities were evaluated on two separate tracks:

- First, the ISO reviewed data on the certified operational characteristics of the existing generation and pumped storage resources to gain insight into capacity with different ranges of start-up times, ramp rates and regulation capacity and ramp rates. The ISO also analyzed historical operational and market data to evaluate what additional operational flexibility might be available in current operations to accommodate renewable integration (i.e., without requiring changes to market operations or procurement of additional reserves).

- Second, the ISO has used both deterministic and stochastic production simulations to estimate whether the generation fleet possesses the capability to meet load in both hourly and sub-hourly time frames and supply the required ancillary services, under 20 percent RPS.

This section is organized as follows. Common data and assumptions for the simulations are described first, along with some further characterization of net load in 2012. The statistical methodology used for determining the regulation and load-following requirements is described generally in Section 2.4. The production simulation methodology and description of data and assumptions specific to those simulations are provided in Section 2.5.

2.1 Study Scenario Data and Assumptions

This section describes the common assumptions and data used in development of the scenarios for 20 percent RPS.

2.1.1 Load

As noted, the year 2012 was selected as the target year for the 20 percent RPS. The load profiles for 2012 were developed by scaling actual 1-minute ISO Balancing Area load data from two base years – 2006 and 2007 – using an annual load growth factor of 1.5 percent. The years 2006 and 2007 were selected to permit an assessment of the effects on fleet capability under distinct hydro conditions, with 2006 being a high-hydro year and 2007 being a low-hydro year. The use of base year 2006 is further consistent with the decision to apply conservative, i.e., stressful, assumptions in the analysis whenever appropriate since 2006 represents a greater than average ISO coincident peak load condition.

The application of a linear annual load growth factor of 1.5 percent from 2006 and 2007 may result in an overestimate of demand and peak in 2012 when compared against the California Energy Commission's (CEC) revised 2012 forecast included in its December 2009 California Energy Demand Forecast 2010-2020.[31] Table 2.1 sets forth the annual net energy and the coincident peak growth rates assumed by the CEC for the ISO Balancing Areas for the 2009 revised forecast, which reflected the impact of reduced economic activity during 2008-2010 and from a prior 2007 forecast. Table 2.2 reflects the load data used in the study and includes a comparison to both the prior 2007 CEC demand forecast and the revised 2009 CEC estimate. The total demand used in the study for 2012 (2006 base year) is approximately 10 percent greater than the CEC's current estimate of 2012 demand, while the non-coincident peak load for 2012 (2006 base year) is approximately 5 percent higher than currently anticipated by the CEC. However, in order to assess the impact of the potential additional load, the ISO has performed production simulations based on 2006 demand without the 1.5 percent annual load growth factor. The demand in this sensitivity exceeds the 2009 CEC demand forecast by approximately 2 percent.

The use of the higher demand assumption is consistent with study's primary objective of assessing the capability of the thermal generation fleet to reliably integrate a 20 percent RPS renewable resource portfolio. The effect of potentially overestimating demand is to more severely test the ability of the existing generation fleet to account for both greater than average load conditions and the integration of a concomitantly higher level of renewable resources (adjusted to meet the 20 percent RPS at the higher load). Relatively higher levels of renewable resources will increase the overall system variability and uncertainty and need for operational flexibility.

[31] See CEC, California Energy Demand 2010-2020 Adopted Forecast available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

Table 2.1: CEC Average Annual Net Energy[32] and Average Peak Growth Rates[33]

Year	Annual Average Net Energy		Average Annual Peak Growth Rates	
	CEC Forecast 2007 – Statewide	CEC Forecast 2009 – ISO Balancing Area	CEC 2007 Forecast – Statewide	CEC 2009 Forecast – ISO Balancing Area
2008 – 2010	1.39 percent	-0.99 percent	1.43 percent	0.82 percent
2011 – 2015	1.21 percent	1.22 percent	1.31 percent	1.50 percent
Avg.	1.28 percent	0.39 percent	1.36 percent	1.25 percent

Table 2.2: Demand Assumptions in 2012[34]

Service Territory		Base Year 2006	Base Year 2007	CEC 2007 Forecast	CEC 2009 Forecast Adopted
PG&E	Base Year Energy (GWh)	107143	108290		
	Base Year Peak (MW)	22635	21196		
	2012 Energy (GWh)	117155	116659	113238	111113
	2012 Peak (MW)	24750	22834	24699	24112
SCE	Base Year Energy (GWh)	111560	112507		
	Base Year Peak (MW)	23340	23830		
	2012 Energy (GWh)	121985	121202	111562	102408
	2012 Peak (MW)	25521	25672	24805	23522
SDG&E	Base Year Energy (GWh)	21498	21513		
	Base Year Peak (MW)	4476	4602		
	2012 Energy (GWh)	23507	23176	22606	21682
	2012 Peak (MW)	4894	4958	4842	4640
ISO Total	Base Year Energy (GWh)	240201	242310		
	Base Year Peak (MW)	50451	49628		
	2012 Energy (GWh)	262646	261037	247406	235203
	2012 Peak (MW)	55165	53463	54346	52274
Note:	Total Peaks are non-coincident				

32 *Id.* at P. 13 (Table 3) and 16 (Table 4).

33 *Id.* at P. 13 (Table 3) and 20 (Table 5), Statewide peak growth rates apply to a non-coincident peak, while the ISO annual peak growth rates apply to a coincident peak.

34 *Id.* at P. 55 (Table 10), 89 (Table 14) and 123 (Table 18),

2.1.2 Renewable Resource Portfolios by Capacity

The study models two renewable resource portfolios:

- a “20 percent RPS” portfolio that models 20 percent renewable energy in 2012 based on data developed by the California Public Utility Commission (CPUC); and

- a “2006 Reference” portfolio which includes only renewable resources on-line in 2006 to provide a reference to the 20 percent RPS results.

In both cases, the remainder of the generation fleet consists of resources that were on-line through 2006 within the ISO’s footprint and the addition of 3,263 MW of new thermal generation facilities expected to be on-line by 2012.

The 20 percent RPS portfolio being modeled has some significant differences from the one modeled in the 2007 Report. In 2006, when the prior study assumptions were developed, the prevailing view based on Load Serving Entity (LSE) contracts and ISO generation interconnection queue positions was that wind would constitute the predominant incremental in-state renewable technology to achieve 20 percent RPS. Wind resource capacity *additions* consisted of a total of 4,040 MW: 3,540 MW located at Tehachapi and 500 MW located at Solano. Although the 2007 Report also assumed a significant amount of new geothermal and biomass resources, it noted that those types of resources are not variable and hence their integration into the ISO is not anticipated to cause material operational issues. Moreover, the 2007 Report assumed that the interconnection of less than 1000 MW of central station solar power by 2010, as estimated at the time, would not result in significant integration requirements. As a result, the analysis of operational requirements in the 2007 Report focused exclusively on the impact of wind resources.

Since 2007, solar projects have become a significantly higher percentage of the portfolio of renewable resources under contract with investor owned utilities as well as of those supply resources generally seeking to interconnect by 2012. Much of the anticipated solar capacity consists of photovoltaic (PV) technologies that have demonstrated substantial variability due to their potential for rapid fluctuations in output.[35] Hence, the ISO determined to examine more explicitly the impact of solar resources on the statistical analysis of operational requirements, as well as in the production simulations. The solar resources are modeled in Barstow, Riverside East 1, Riverside East 2, Mountain Pass/Tehachapi, and include some distributed generation at multiple locations.

[35] E.g., as noted by NERC, “PV systems can experience variations in output of +/- 50 percent in the 30 to 90 second time frame and +/- 70 percent in a five to ten minute time frame. Furthermore, the ramps of this magnitude can be experienced many times in a single day during certain weather conditions. This phenomenon has been observed on some of the largest PV arrays (ranging from 3-10 MW) deployed in the U.S. located in Arizona and Nevada.” See NERC, “Special Report: Accommodating High Levels of Variable Generation” at p. 27, available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

To provide a reference for changes on the power system, the ISO also modeled a "2006 Reference" scenario in which only renewable resources in operation in 2006 are considered in the simulations. This case is analyzed to measure the incremental impact of renewables in the production simulation. In the statistical analysis of operational requirements, this 2006 scenario is also modeled using 2006 loads to show the increase in requirements arising from the change in load from 2006 to 2012. Table 2.3 summarizes the installed capacity (MW) in each of the scenarios, including both renewable and conventional generation technologies.

Table 2.3: Installed Capacity (MW) of the 2012 Cases by Generation Type

	2006 Reference Case	2012 20 Percent RPS Case
Biomass/BioGas	701	701
Solar	420	2,246
Geothermal	1,101	2,341
Small Hydro	614	614
Wind	2,648	6,688
Total ISO Installed Renewable Capacity	5,484	12,590
Thermal	32,308	32,308
Large Hydro	7,166	7,166
QF	3,555	3,555
Nuclear	4,550	4,550
Total ISO Installed Conventional Capacity	47,579	47,579
Total ISO Installed Capacity	53,063	60,169
ISO Planning Reserve 17 Percent	64,543	64,543
Import Contribution to Capacity	12,711	12,711
Total Resources	65,774	72,880

The incremental renewable portfolio used in the study is intended to be consistent with assumptions made by state agencies and, in particular, the CPUC on the resource mix by technology and location (including in-state and out-of-state). As such, the expected wind capacity remains essentially the same as in 2007 Report, but the incremental geothermal and solar capacity is patterned after the 20 percent RPS reference case developed by the CPUC as part of its 33 percent RPS Implementation Analysis conducted in 2009.[36]

[36] See, CPUC, 33 percent Renewables Portfolio Standard, Implementation Analysis, Preliminary Results (June 2009), available at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

2.1.3 Aggregate Energy Production by Renewable Resources

The renewable resource capacity (MW) requirements shown above are determined by a combination of specific projects and the renewable energy requirements under 20 percent RPS. In turn, the total annual energy production by resource type is then converted into energy production profiles, based on the capacity factors of each technology by location, for each time interval being analyzed. Table 2.4 shows the annual energy production (GWh) associated with the mix of renewable resource capacity shown in Table 2.3.

Table 2.4: Renewable Energy Production (GWh) in the 20 percent RPS Scenario

Resources	Energy (GWh)
Wind (ISO)	17,886
Solar	4,907
Small Hydro	1,047
Biomass/Biogas	4,753
Geothermal	19,225
Wind (Out-of-State)	6,062
Total Renewable Resources	53,879
Total of All Resources	263,646
Renewables as a percentage of total resources	***20.4 %***

2.2 Development of Wind and Solar Production Profiles

The study uses a wind production profile for 2012 that was developed by AWS Truepower for the 2007 Report[37] and which located the incremental wind additions at Tehachapi and Solano. The expected wind production data was simulated using actual production data from January 2002 to December 2004 combined with atmospheric simulation models to create wind speeds for the resource areas. The maximum wind production level in the data set is 6,000 MW at times. Additional information on the development of the wind production data can be found in the technical appendix.

For both solar thermal and solar PV resources, production profiles by plant were also developed and were located at five CREZs and some distributed locations. A method

[37] This data was also used in the CEC IAP Study (http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF).

was developed to simulate locational variability in production due to changes in irradiance and the operating characteristics of each technology type.[38]

The final wind and solar production profiles used in the "2006 Reference" case and "20 Percent RPS" case were developed on a 1-minute time-step, corresponding chronologically to the load data for each period studied. Similarly to the graphs shown in Figure 1-2 and Figure 1-3 in Section 1, these profiles reflect the inherent variability of the wind and solar production for the target year (as well as load variability). Figures 1-9 through 1-12 in Section 1 plot the average hourly 2012 production data for wind in each season by operating hour.

2.3 Load Net of Renewable Energy by Season in 2012

Because both the renewable energy profiles and the load are fixed inputs into the models, the net load in each hour – load minus renewable energy production – can be calculated ex ante. This section shows the net load by season in 2012 as background to some of the subsequent simulation results.

Figure 2-1 toFigure 2-4 illustrate the *average hourly* load, net load and wind and solar generation in California for each of the four seasons in 2012 (as noted in Section 1, the average hourly production is not reflective of the actual hourly variability of wind and solar resources).[39] Load and net load MW are measured on the left horizontal axis (or y-axis), while wind and solar generation are measured on the right horizontal axis (or y-axis). The figures show that due to solar production, the net load now decreases in the daily peak hours in all seasons. This results in more displacement of daily peak hour thermal generation than the incremental wind-only scenario modeled in the 2007 Report. Section 5 discusses the exact energy displacement (GWh) by season as well as price and revenue impacts.

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[38] The existing solar resources were modeled using ISO 1 minute production data. For the new plants, a different production profile data set was constructed for each technology type – solar PV with tracking, solar PV without tracking and solar thermal which used the trough model – at each location that captured differences in hourly solar irradiance, the time delay in how particular technologies respond to irradiance, and the effect of cloud cover on locations with multiple plants. The methodology is explained in detail in the technical appendix.

[39] That is, the hourly average production across all similar hours in the season using the data sets for the production profiles in the simulation models discussed in Sections 2-5. The averaging is why wind production appears much lower than its full rated capacity in 2012.

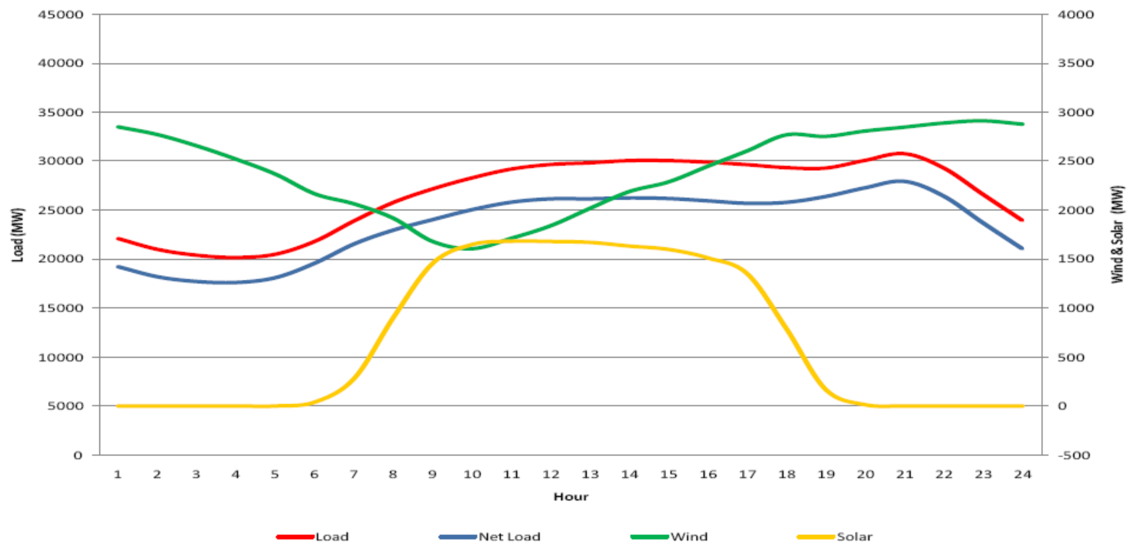

Figure 2-1: Simulated average hourly load, net load and wind and solar generation, Spring 2012

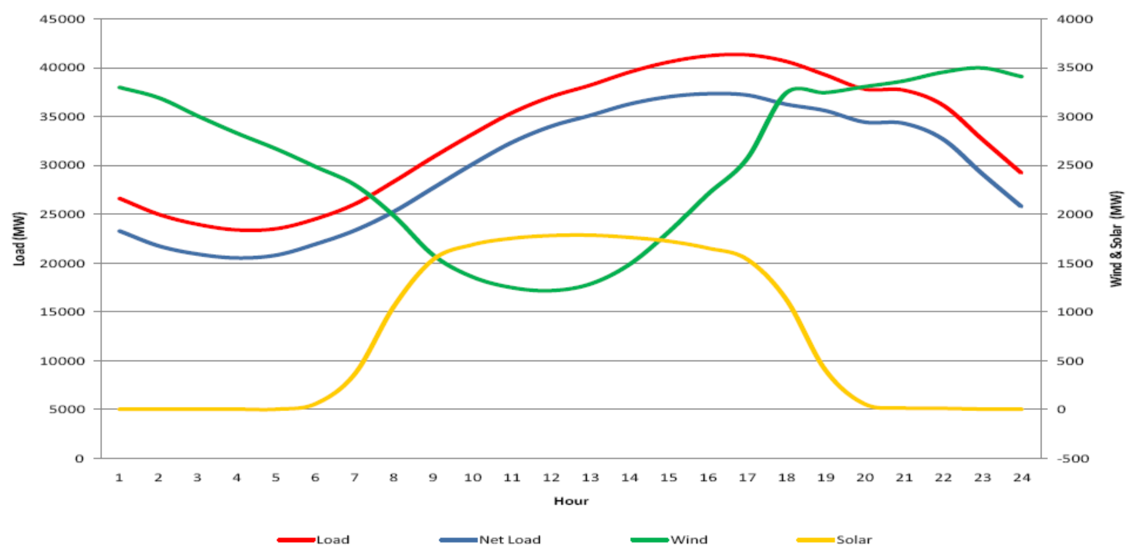

Figure 2-2: Simulated average hourly load, net load and wind and solar generation, Summer 2012

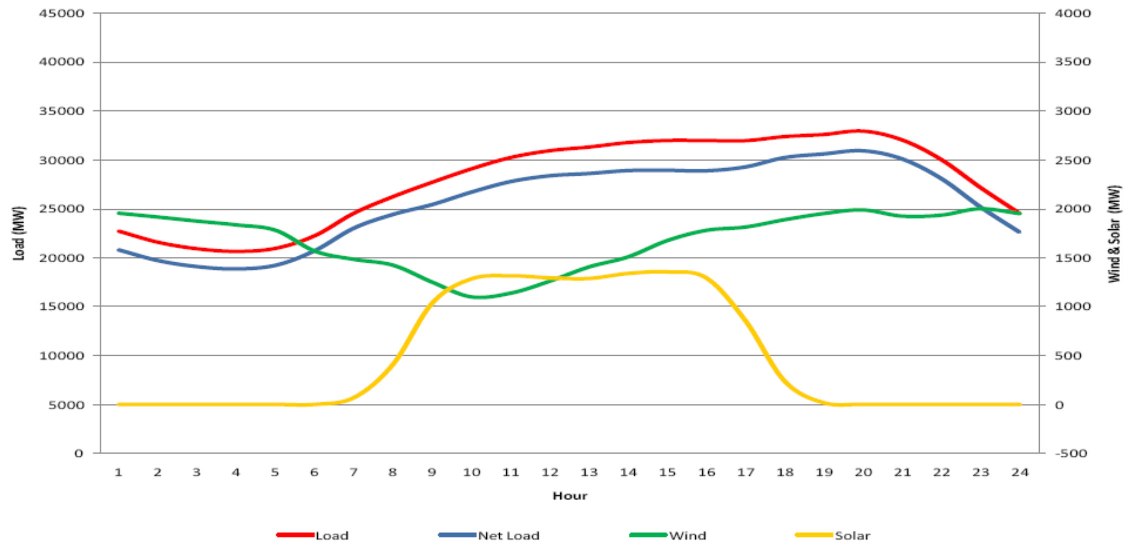

Figure 2-3: Simulated average hourly load, net load and wind and solar generation, Fall 2012

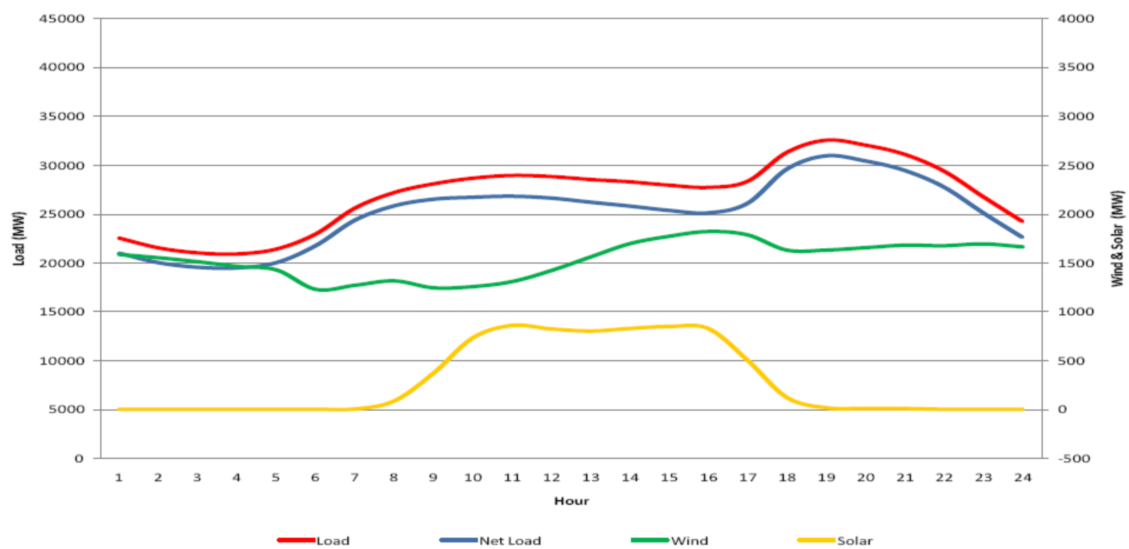

Figure 2-4: Simulated average hourly load, net load and wind and solar generation, Winter 2012

2.4 Methodology for Determining Operational Requirements

A key component of renewable integration studies is statistical analysis, including simulation through stochastic processes, of the potential deviations in wind and solar generation over various operational and market time frames – e.g., day-ahead to hour-ahead; hour-ahead to 5-minute; 5-minute to one-minute – due both to variability and forecast error. These deviations are measured in terms of operational ramping (various time frames), load-following capacity (typically deviations within the operating hour on a 5-minute basis) and regulation capacity (typically deviations from 5-minute schedules to

1-minute actual generation), and can then be evaluated against the operating characteristics and capabilities of system resources, as discussed in subsequent sections. This section begins with an overview of the statistical methodology used in this study, followed by more detailed discussion of how the regulation and load-following requirements are calculated.

2.4.1 Overview of the Operational Requirements Simulation Methodology

There are several statistical methodologies that have been used in renewable integration studies to determine hourly and sub-hourly operational requirements and, by inference, integration costs.[40] This study uses a stochastic process developed by the ISO and Pacific Northwest National Laboratory (PNNL)[41] that employs Monte Carlo simulation, which uses random sampling over multiple trials or iterations to estimate the statistical characteristics of a mathematical system. The simulation is designed to model aspects of the daily sequence of ISO operations and markets in detail, from hour-ahead to real-time dispatch. The objective is to measure changes in operations at the aggregate power system level, rather than at any particular location in the system. The model provides realistic representations of the interaction of load, wind and solar forecast errors and variability in those time frames and evaluates their possible impact on operational requirements through a very large number of iterations. The model also incorporates some representation of system ramps between hours to improve accuracy.

A detailed description of the statistical analysis methodology is found in the technical appendix issued separately from this document. The basic method is as follows. First, the load and renewable production data is aggregated from the 1-minute data set to create averaged hour-ahead and 5-minute dispatch schedules for each hour of the year.

Second, the probability distributions of forecast errors, and other statistical properties, such as autocorrelation, for load, and wind and solar production in the hour-ahead and 5-minute-ahead timeframes are constructed. These distributions were developed from various sources, including the ISO and AWS Truepower data on wind forecast errors by location in California, and available data and additional modeling of solar forecast errors. Solar forecast error data is not yet widely available, so a detailed model to estimate those errors was developed that took into consideration the annual and daily patterns of solar irradiance, an hour-to-hour clearness index,[42] dynamic patterns of the cloud systems, types of solar generators, geographical location and spatial distribution of solar power plants, and other factors. Both wind and solar forecast errors are used in the hour-ahead random draws. However, in the 5-minute time frame, the ISO uses a wind persistence

[40] Earlier studies of California operational requirements using alternative statistical methods include the California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF (hereafter "CEC IAP Study"). The ISO's 2007 Report adopted a different statistical method, which is developed further in the present study.

[41] See Makarov, et al., "Operational Impacts of Wind Generation on California Power Systems," *IEEE Transactions on Power Systems*, Vol. 24, No. 2, (May 2009) at 1039.

[42] The clearness index is a measure of the actual solar irradiance divided by the maximum solar irradiance; see the technical appendix.

forecast, which is the basis for the simulation. Hence, in the 5-minute sampling, the wind variability is preserved but the forecast error is static for the period of the persistence model. For the solar resources, the 5-minute persistence forecast is based on the clearness index, but the morning and evening ramp periods for solar are also modeled explicitly, during which persistence would not be an appropriate assumption.

Third, the Monte Carlo sampling then conducts random draws from the load, wind and solar forecast errors, with consideration of autocorrelations between the errors, to vary the initial hour-ahead and 5-minute schedules. The Monte Carlo sampling is done on each hour in the sequence individually.[43]

To facilitate analysis, the values generated from the sequence of hours being modeled are evaluated on a seasonal basis and the results for each hour are presented at that level of granularity (i.e., by season, by hour of day). These hourly results by season are shown in Section 4 and Appendix A. The seasonal time frame for presenting results was considered to provide sufficient information on changes in operational requirements over the season, and to capture sufficient variation among the seasons.

Each simulation of a seasonal case includes 100 iterations over all hours in the season to capture a large number of randomly generated values. Of these simulated values, five percent are eliminated as extreme points, using a methodology that considers all dimensions being measured in the analysis (capacity, ramp and ramp duration).[44] In the discussion that follows in Section 4, the ninety-fifth (95^{th}) percentile value is called the "maximum".

Fourth, the remaining values from each full set of iterations are then evaluated using different measures. For example, the 2007 Report showed the maximum value for each operating day hour (i.e., Hour 1 through Hour 24) across the season, to highlight the maximum operational stress likely to be experienced. This study also shows the distribution (maximum, minimum, and average ± one standard deviation) of the maximum values for all hours in the seasonal simulation, to provide more information on the frequency of particular values across the season.[45] However, the basic methodology is the same in both studies.

The specific application of this methodology to evaluate load-following and regulation requirements is discussed in the next sections.

[43] However, the twenty (20) minute ramps that characterize the boundary between actual hourly schedules are represented in the model to ensure that in those periods, deviations between the underlying schedules and the random draws do not exaggerate the result.

[44] See discussion in the 2007 Report and the technical appendix to this report.

[45] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour in the season. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, and so on.

2.4.2 Determination of simulated load-following requirements

The statistical methodology described above can be used to evaluate operational requirements that correspond to the time-steps in which the data is sampled. The furthest forward in time that this study evaluates is the transition from hour-ahead schedules to intra-hour schedules and dispatch, which is called load-following. In the context of this analysis and the ISO market, load-following is defined as the intra-hour energy deviations from the hourly schedule, whether in the upward or downward direction. Such deviations can be measured in different ways and on different time-scales within the hour (e.g., 5 minute, 10 minute); generally, in this report, it refers to deviations in the ISO's 5-minute economic dispatch intervals.

Table 2.5 shows four different ways in which this study has measured and evaluated load-following requirements and capabilities, both through simulation and empirical analysis. The methods described in this section are listed as the first two in the table.

As noted above, the underlying data for the Monte Carlo simulation is based on 1-minute data that is then averaged to establish hourly schedules and 5-minute dispatch schedules for each hour. The objective of this approach to the simulation was to model data on time frames that correspond to the ISO's hour-ahead scheduling process and real-time unit commitment process, although the simulation itself does not "connect" each interval that it models through an optimization, as do the actual market processes. The hour-ahead scheduling process runs 75 minutes prior to each operating hour using the wind schedules and load forecasts available at that time. The hour-ahead wind schedule for about half of the wind resources currently on the system is constructed through a centralized forecast and made available to the ISO through the arrangements in the Participating Intermittent Resource Program (described in Section 2). The real-time unit commitment runs on a much shorter time horizon, and creates a schedule for economic dispatch of generators on a 5-minute basis. To restate the methodology in ISO scheduling and market terms, the operational requirements simulation defines load-following as the amount of incremental and decremental energy required to serve the MW difference between the hour-ahead scheduling process schedule and the real-time unit commitment and dispatch schedules for each 5-minute interval in the hour, as discussed next.

As noted above, the random draws of forecast errors then generate one value for each hour of the season and twelve values corresponding to each 5-minute interval within each hour, for each of 100 iterations. The method then calculates two quantities that are relevant to load-following. The first is called "load-following capacity" (MW); the second is called "load-following ramp rate" (MW/5 minutes). Load-following capacity is defined as the maximum difference between the hourly "schedule" MW calculated by the simulation and any 5-minute interval MW within that hour. That is, the largest *potential* movement upward and downward over the hour from the hourly schedule. The load-following ramp rate is defined as the difference between the MW in any two contiguous 1-minute intervals within the dispatch intervals in the hour. The maximum load-following ramp rate is thus the largest of these, and the duration of the ramp rate is also measured ex post. These results are presented in Section 4 to show the distribution statistics or simply the maximum value for each hour of the day by season.

Figure 2-5 shows the analytical flow of the load-following calculation. The full mathematical model is presented in the technical appendix.

Table 2.5: Comparison of definitions of "load-following" in study analysis

Analysis	Term	Description/Definition
Operational requirements simulation (Section 3)	Load-following capacity requirement	The maximum difference between the simulated hourly block schedule and any positive deviation from that schedule in the simulated 5 minute schedules (load-following up) or negative deviation (load-following down)
Operational requirements simulation (Section 3)	Load-following ramp rate	The maximum change between the MW level in any two consecutive simulated 1 minute intervals within an hour; can also be calculated for other intervals within the hour or over multiple hours
Operational capability based on actual market analysis (Section 4)	Actual 5-minute load-following capability	The estimated upward and downward capability of the generation committed and dispatched in actual five minute intervals, based on ramp rates and maximum and minimum operating limits
Operation capability based on production simulation (Section 5)	5-minute Load-following capacity	The cumulative capability of the units dispatched in the simulation to move in 5-minutes, subject to their ramp rates

2.4.3 Determination of simulated regulation requirements

The calculation of the regulation requirements proceeds similarly to the load-following analysis, but measuring deviations between the 5-minute dispatch intervals and the 1-minute data that underlies the analysis. In this case, the method measures the largest 1-minute deviation within the 5-minute period to give the regulation result. The “regulation capacity” requirement is defined as the largest such deviation within an hour. The “regulation ramp rate” is defined as the largest sampled change from minute-to-minute within the 5-minute interval.

Figure 2-6 shows the analytical flow of the regulation calculation, with additional detail available in the separate technical appendix.

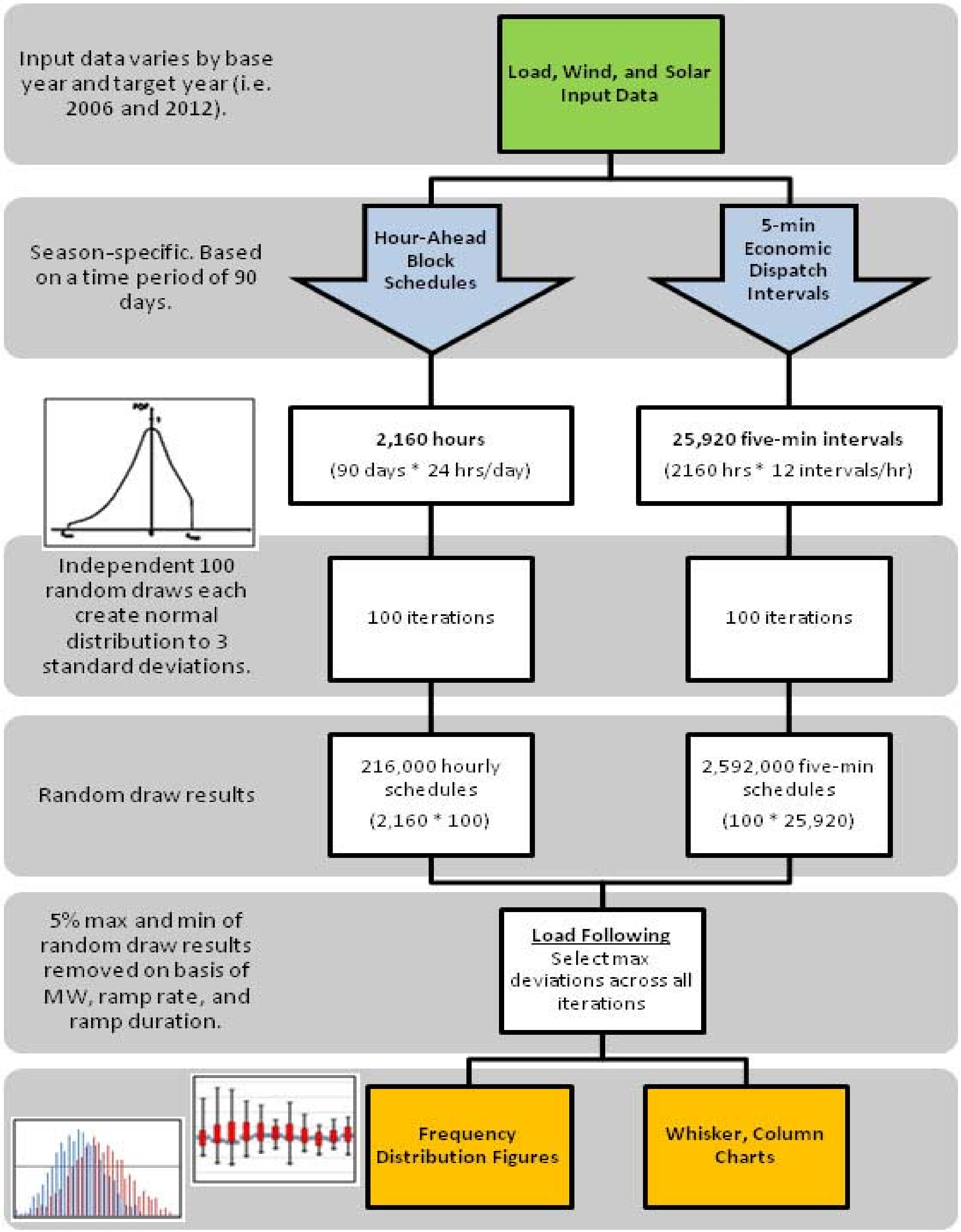

Figure 2-5: Analytical Flow Chart for Calculating Load-following Capacity Requirements

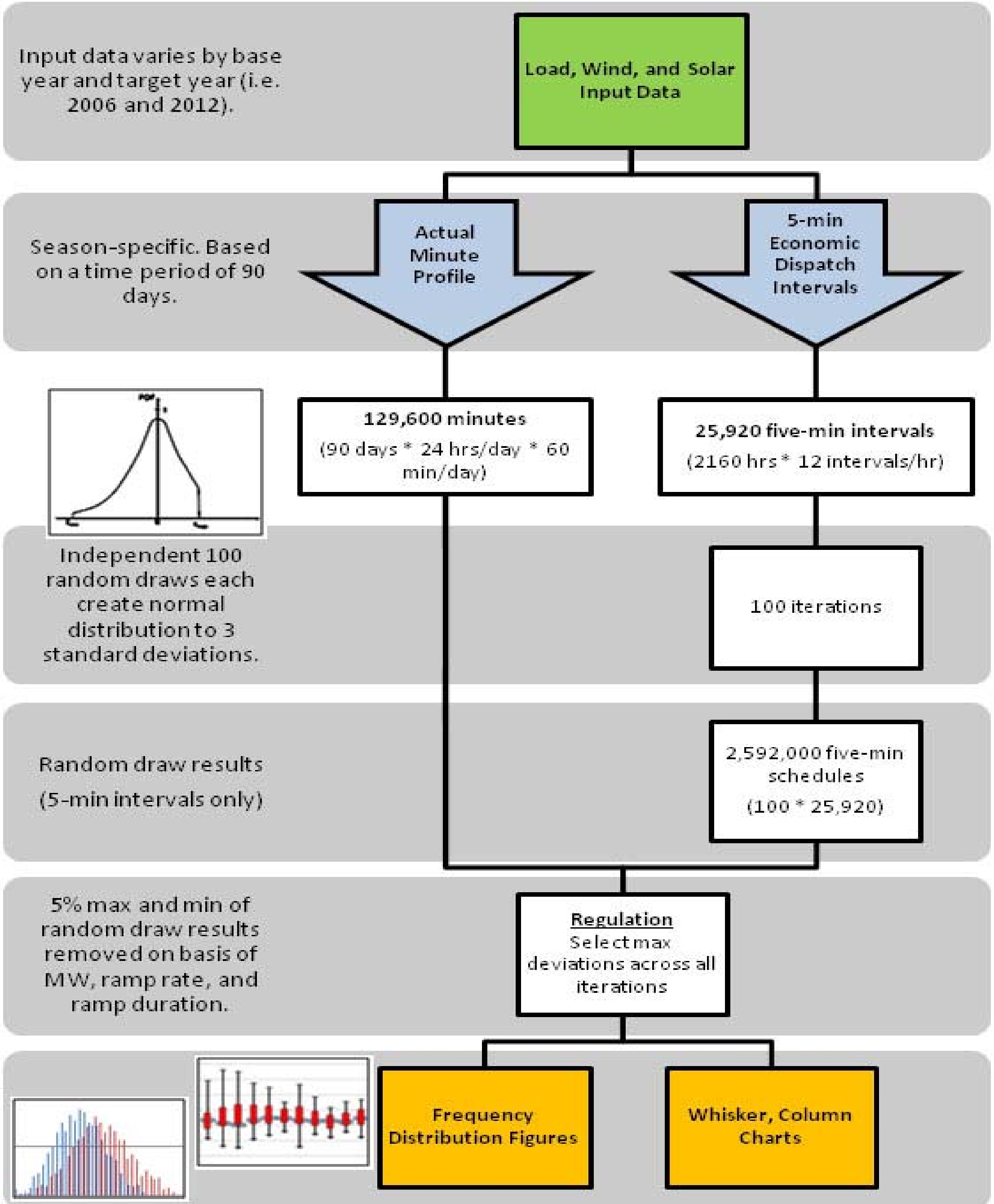

Figure 2-6: Analytical Flow Chart for Calculating Regulation Capacity Requirements

2.5 Production Simulation Methodology for Evaluation of Fleet Capability

One limitation of the operational requirements methodology is that it does not represent the supply side of the power system explicitly. That is, while estimating operational requirements, the statistical analysis does not address the capability of the ISO generation fleet to meet those requirements during market and system operations.

The analysis of generation fleet characteristics, historical bids and the historical dispatch described in Section 4 evaluates whether sufficient regulation and load-following capability exists to meet the integration requirements, based on historical operations. By juxtaposing the historical capability with the future operational requirements, it is possible to arrive at some conclusions regarding the capability of ISO generation fleet to meet the integration requirements with 20 percent renewable generation.

However, to analyze in detail the capability of the fleet to meet the integration requirements, it is necessary to conduct simulations of both hourly and minute-by-minute operations under future load and generation scenarios. The production simulation models developed for this study sought to replicate with a reasonable degree of accuracy the operational and market processes used in the commitment and dispatch of generation. It incorporated all the physical characteristics of the generators, such as ramp rate, start-up costs and time, minimum up-time, minimum down-time, etc. However, it did not include certain generator operating constraints, such as forbidden regions.

Production simulation (or production cost modeling) refers to the use of large-scale computer-based models that incorporate a detailed representation of generation, demand and transmission over a wide region to simulate least cost commitment and dispatch of generators subject to operational constraints and determine marginal prices at different locations in the system. Due to their scale, these types of models are typically used for planning purposes and not for market or operational evaluation. However, over recent years, many models have incorporated sufficient detail on generation and transmission network parameters, as well as updated their optimization algorithms for efficient unit commitment solutions, such that they are now also used to evaluate shorter-term market and operational conditions. Typically conducted on an hourly time-step, current state-of-the-art production simulation models can represent both unit commitment – the decision whether to start (commit) or stop (decommit) a particular resource in a particular period – and dispatch – the actual output from a particular resource in a particular period. They also explicitly represent key generation operating characteristics, such as start-up times, ramp rates and minimum up and down times.

Most of the large-scale regional wind integration studies to date have employed production simulation models to evaluate the capability of generation and non-generation resources to meet energy and ancillary services requirements under different future conditions.[46] These production simulations have used an hourly time interval for

[46] For a recent survey, see M. Milligan, et al., Large-Scale Wind Integration Studies in the United States: Preliminary Results, Conference Paper, NREL/CP-550-46527, September 2009; See also California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; See also several

dynamic optimization, with the capability of the system to meet the sub-hourly requirements such as load-following evaluated heuristically based on the results of the hourly simulation and not explicitly determined via sub-hourly optimization. Also, most of the prior studies have employed deterministic production simulation, which does not adequately model the impact of uncertainties in load and variable generation. The stochastic, sequential simulation methodology employed in this study was designed to overcome the above-mentioned problems. This methodology is described below in Section 2.5.2 in detail. The data and assumptions used in the production simulation model are described next.

2.5.1 Data and Assumptions

The major objective of production simulation is to model the least cost operation of a power system while ensuring that the system's security constraints are not violated. Security constraints include the operating limits and capabilities of generation sources, constraints and contingencies imposed by the transmission system and the operational limits such as minimum operating reserve levels. The primary inputs are hourly loads, generator capacity and characteristics, fuel prices and transmission constraints that need to be monitored. This section provides the data and assumptions for the production simulation model used in this study.

2.5.1.1 General data and categorizations

The source for the identity and operating characteristics of the conventional resources incorporated into the production simulation model was the full network model used for allocation of ISO congestion revenue rights, and the ISO Master File, respectively. The ISO's Master File data includes all key generator confidential operating characteristics such as Pmin, Pmax, minimum up and down times, ramp rates, start times, heat rates, and ancillary service certified ranges. Table 2.6 describes how classes of resources are modeled in the production simulations. In this analysis, the generation from certain resources such as biomass, geothermal, and Qualifying Facilities (QFs) are assumed to be fixed based on historical operations. Hydro generation, although dispatchable, is assumed to be fixed based on either 2006 or 2007 hydro data, in order to study two different extremes in hydro generation. Similarly, a portion of imports is assumed to be fixed to reflect historical operations. Only gas-fired units are dispatchable in this analysis. These assumptions are further explained in the sections below.

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studies conducted by GE Consulting, including New York State Energy Research and Development Authority's "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, " available at http://www.nyserda.org/publications/wind_integration_report.pdf ; Ontario Power Authority, Independent Electricity System Operator, Canadian Wind Energy Association, "Ontario Wind Integration Study," available at http://www.powerauthority.on.ca/Storage/28/2321_OPA_Report_final.pdf ; Electrical Reliability Council of Texas, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," available at http://www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip.

Table 2.6: Modeling assumptions about production profiles and flexibility by generation resource type and imports

Generation Type	Production Simulation -- Assumptions about Commitment and Dispatch
Solar	Simulated production profiles based on solar irradiance data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Wind	Simulated production profiles from historic production data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Biomass	Scaled historic production profile; constant over the day; not dispatchable
Geothermal	Fixed production profile; constant over the day; not dispatchable
Thermal	Dispatchable in each time-period within generation operating parameters
Hydro	Historical production and ancillary service profile (2006 and 2007); typically constant over the day; not dispatchable
Nuclear	Fixed production profile; constant over the day; not dispatchable
QF	Historic production profile; constant over the day; not dispatchable
Imports	Historic injection for 2006 and 2007; varies by hour; not dispatchable (but varied in sensitivity analysis)

2.5.1.2 Existing Conventional Gas Resources

Thermal resources in the study provide about 32,308 MW of the capacity within the ISO BAA, which would account for approximately 54 percent of the ISO's total resource mix in 2012. Gas plants are particularly important because they currently provide most of the ramping and ancillary service capability for the ISO. In this study, the gas-fired generation is assumed to be dispatchable; i.e., self-schedules of gas-fired generation are not modeled.

Tables 2.7 through 2.9 provide summaries of the various technology types and some of their operational characteristics.

Table 2.7: Ramp rates of ISO generation fleet

Generation Type		Ramp Rate (MW/min) by Category						
		RR < 0.5	0.5 ≤ RR < 1	1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle			4,885	4,630	3,617		13,132
	Dynamic Schedule				552	1,746	2,379	4,676
	Gas Turbine	32	68	1,040	4,635	1,601	553	7,929
	Hydro	99	157	427	1,135	1,927	3,671	7,416
	Other	5	4	14	1,633		4	1,660
	Pump/Storage				440		1,792	2,232
	Recovery	61	17	115	13			206
	Steam	357	355	1,328	747	59		2,847
	Not specified	5	6	42	1,568	20	525	2,165
Non-OTC Unit Total		559	607	7,851	15,353	8,970	8,924	42,263
OTC units	Combined Cycle			600				600
	Gas Turbine			15				15
	Steam		354	8,542	5,650	1,516	1,510	17,573
OTC Unit total		0	354	9,158	5,650	1,516	1,510	18,188
All Units Total		559	961	17,008	21,003	10,486	10,434	60,451

Table 2.8: Definitions and characteristics of units based on start-times

Attribute	Fast-Start	Short-Start	Medium-Start	Long-Start	Extremely Long-Start
Start-up Time	Less than or equal to 10 minutes	Less than 2 hours	Between 2 & 5 hours	Between 5 & 18 hours	Greater than 18 hours
Cycle time		Less than 5 hours	Less than 5 hours		

Table 2.9: Start up times of ISO generation fleet

Generation Type		Start-up Times (minutes) by Category: ST < 10	10 ≤ ST < 120	120 ≤ RR < 300	300 ≤ RR < 10,800	unknown	Total MW
Non-OTC Units	Combined Cycle		174	1,241	11,717		13,132
	Dynamic Schedule				3,650	1,026	4,676
	Gas Turbine	1,261	2,161	191		4,317	7,929
	Hydro	4,908	1,382	486		640	7,416
	Other	352	294	377		636	1,660
	Pump/Storage	2,232					2,232
	Recovery	19	35	114		37	206
	Steam	267	169	221	1,760	430	2,847
	Not specified	360	114	19		1,672	2,165
Non-OTC Unit Total		9,400	4,329	2,649	17,127	8,759	42,263
OTC units	Combined Cycle			109	491		600
	Gas Turbine					15	15
	Steam				15,127	2,446	17,573
OTC Unit total				109	15,618	2,461	18,188
All Units Total		9,400	4,329	2,758	32,745	11,220	60,451

2.5.1.3 Expected Additional Conventional Gas Resources by 2012

Table 2.10 shows the new and planned thermal resources that were included in the analysis. These resources were included as they are currently under construction and have little or no risk of not being available in the 2012 timeframe. No resource retirements were modeled, nor were sensitivities conducted for the status of once-through cooling (OTC) plants. OTC plants are slated to be retrofitted or shut down after 2013 and are not expected to affect the 20 percent RPS integration. However, they could affect renewable integration after 2013, and hence are being examined in the ISO's 33 percent RPS operational study.

Table 2.10: New Resource Additions by 2012

	New Resources	Max. Cap. (MW)	Location	Commission Date
1	EIF_Panoche_2_PL1X2	400	Fresno, NP15	August 2009
2	GateWay_2_PL1X4	530	Contra Costa, NP15	May 2009
3	Humboldt_1_PL1X2	163	Humboldt, NP15	April 2010
4	Inland_Emp_2_PL1X4	800	Riverside, SP15	Unit 1: Nov. 2008 Unit 2: July 2009
5	Otay_Mesa_2_PL1X2	590	San Diego, SP15	October, 2009
6	Starwood_1_PL1X2	120	Fresno, NP15	May 2009
7	Colusa Generating Station	660	Colusa, NP15	October, 2010
Total		3,263		

2.5.1.4 Imports of Energy and Ancillary Services

To simplify the analysis, and to keep it focused on the operational capabilities of the generation fleet under ISO dispatch control, the production simulation used fixed imports of energy based on historical import data. The ISO is a net importer of energy and this is not likely to decrease in the near future. The 2012 import levels used in this study were based on the actual import profiles for 2006 and 2007. As discussed further in the next section, during high hydro years within the ISO's footprint, imports are significantly lower than they are during low hydro years. Thus, the combination of the hydro patterns and imports for 2006 and 2007 are a useful starting point for examining the sensitivity of renewable integration to alternative system conditions.

During the off-peak hours in 2006, the average imports exceeded 5,100 MW in the spring and 5,500 MW in the summer months. During the off-peak hours in 2007, the average imports were 7,000 MW in the spring and 6,900 MW in the summer. Some of the reasons for high import levels during the off-peak hours are jointly owned units that are dynamically scheduled into the ISO, load-serving entity contracts to purchase base-loaded energy from out-of-state coal plants, and external resources that are needed to serve the ISO's peak demand but cannot be shut down by the host balancing authorities due to their long start up times and shut down times between starts. In cases where the ISO needs the peak energy from an external resource it may have to also take the minimum generation from that resource during the off-peak hours because the host balancing authority may not need the off-peak generation.

In the model, ancillary services imports over the interties were assumed to be zero, in part due to the limitations of the model to represent dispatch of external resources and also because the analysis was focused on the renewable integration capability of the existing in-state generation fleet.

It is expected that the energy import levels modeled here will be available in 2012; the study did not scale up the imports (i.e., assume that there will be additional surplus generation outside the ISO) on the assumption that in other regions, generation additions will at least keep up with expected load growth.

To examine the sensitivity of the results to import assumptions, the production simulation analysis included several alternative cases that varied the level of imports considered fixed and the level considered dispatchable. Subsequent studies, notably the forthcoming 33 percent RPS operational study, will use a WECC-wide model that can examine regional energy trade balances and ancillary service provision.

2.5.1.5 Hydro Resources

The off-peak hydro production levels could average 3,822 MW (49 percent) of total capacity during the spring, about 2,707 MW (35 percent) in the summer and 2,337 MW (30 percent) during the winter months. Also in the spring, high temperatures can result in early snow melt and high hydro production levels, which can result in overgeneration conditions because the off-peak loads in the spring is typically about 2,000 MW lower than the off-peak loads in the summer. Since the hydro capacity is expected to remain about the same in the 2012 timeframe, the realized hydro production levels can greatly influence the amount of wind generation that can be accommodated into the resource mix.

The study used two sensitivities for hydro production: a high hydro case based on actual production in 2006; and a low hydro case based on actual production in 2007. The ancillary services (spinning reserve, non spinning reserve and regulation) awarded to hydro resources were assumed to be the same as 2006 and 2007.

Table 2.11: Comparison of Hydro and Imports in 2006 and 2007 (GWh/yr)

	2006	2007	percent diff.
CA hydro	48,876	26,958	-45 %
CA net imports:			
From NW	19,808	24,669	25 %
From SW	44,959	67,547	50 %
Total	**64,767**	**92,216**	**42 %**

The hydro profiles used in the simulation were actual production for 2006 and 2007. 2006 was declared a high hydro year due to the higher than normal rainfall, snowpack and reservoir storage levels. By comparison, 2007 was declared a normal hydro year.

Overall, hydro production was 48,876 GWh in 2006 and 26,958 GWh in 2007, a reduction of 45 percent. The ancillary services modeled in the production simulation studies were assumed to be the same as was provided by the hydro resources in 2006 and 2007.[47] Typically, during high hydro years in California, the ISO imports are significantly lower than during dry hydro years. As shown in Table 2.11, a high hydro year has a significant impact on imports.

[47] Availability of hydroelectric production is a major influence on the availability of regulation. Hydroelectric resources typically provide a large fraction of the regulation utilized by the ISO, and are among the most flexible resources available, so anything that impacts their ability to provide the service has a noticeable impact on the market. Water conditions can directly affect the capability of hydro resources to provide regulation. In 2006, hydro generation was at high capacity, such that hydro generators were forced to either generate at maximum capacity or allow water to go over spillways. Under these circumstances, hydro units had no spare capacity to provide for regulation and other resource types were used to make up for reduced hydro availability. In the spring of 2006, there was insufficient upward regulation capacity in the market a total of 104 hours, distributed fairly evenly across all hours of the day. Upward regulation from hydro resources hovered in the 150 MW range in 2006, but was in the 200 MW range in the comparatively lean water year of 2007. In the spring of 2007, hydro units were not producing energy at their maximum capacity, and were therefore able to offer regulation capacity to the market. By comparison, insufficiency occurred in only 5 hours during January through May 2007 period, when water levels were much lower.

2.5.1.6 Modeling of Other Generation Resources

In 2006, of the four nuclear units within the ISO area, two units were off-line for some time in the spring and one unit was off-line for a period of time during the fall and winter months. In subsequent years, it is highly likely that all four units would be on-line and generating at their maximum capacity during off-peak hours. Therefore, all four nuclear units were modeled at a combined full output of 4,550 MW.

Qualifying Facilities (QFs) were modeled at their historic production profiles in 2006 and 2007; actual QF production does not vary much from one hour to the next and is not modeled as dispatchable (typically, QFs are only given dispatch instructions when the ISO declares an emergency). Although geothermal and biomass resources are classified as QFs, for accounting purposes, their actual production was not included in the QF total but instead counted as renewable energy to meet the RPS.

2.5.1.7 Renewable Resource Operational Characteristics

All RPS-eligible renewable resources, including variable generation renewables, were modeled as fixed output (or “must-take”) generation. Wind and solar production profiles were discussed above in Section 2.2. Geothermal, biomass and small hydro facilities were modeled based on their historic production profiles realized in 2006 and 2007 and incremented to 2012 production levels as appropriate.

2.5.1.8 Load Forecasts and Assumptions

Load forecast assumptions were discussed in Section 2.1. The minute-by-minute load data for 2012 was averaged to obtain the 5-minute and hourly load for the production simulations. The methodology used for simulating day-ahead and hour-ahead loads using forecast error is described in the technical appendix.

2.5.1.9 Network Representation

The ISO service territory was modeled as three transmission regions—PG&E, SCE and SDG&E—but transmission limits were only enforced on Path 26. As noted above, hourly net interchange for NP26 and SP26 were fixed based on 2006 or 2007 actual data. A full network representation was not employed since it would have greatly increased the solution times of the stochastic simulations.

2.5.1.10 Ancillary Service Requirements

The production simulation model co-optimizes energy and ancillary services, such as regulation, spinning and non-spinning reserves. The ancillary service requirements used in the simulations are listed in Table 2.12. As noted above, they include the seasonal maximum regulation requirements by operating hour calculated in the operational requirements simulations. Those actual requirements are shown in Section 3 and Appendix A-1. However, the model did not represent ancillary service procurement requirements on a regional and sub-regional basis.

Table 2.12: Ancillary Service Requirements

Ancillary Service	2007 Report Requirements for Incremental Wind Case	Requirements for Incremental Wind plus Solar Case
Regulation-Down	350-750 *	350-775 *
Regulation-Up	350-530 *	350-525 *
Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)
Non-Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)

* Regulation requirements vary by time of day and season.

2.5.2 Stochastic Sequential Production Simulation Methodology

For this study, the ISO developed a more detailed modeling approach to production simulation than most prior renewable integration studies. A stochastic, sequential production simulation with the capability to simulate both hourly commitment and dispatch and 5-minute real-time dispatch was developed for this study. The methodology considered the impact of day-ahead and hour-ahead wind and load forecast errors on unit commitment and dispatch, thereby replicating to some degree the actual sequence of those forward markets and procedures. As discussed below, the hour-ahead commitment is then frozen and the units dispatched to serve net load across 5-minute "real-time" intervals. This process is repeated for 100 iterations to test the impact of multiple possible forecast errors that need to be resolved in the actual dispatch. The technical appendix provides the mathematical details on the methodology.

2.5.2.1 Generation of stochastic load and wind generation forecasts

The further forward in time, the greater the uncertainty about actual (real-time) wind and load due to forecast error. A stochastic process using Brownian motion with mean reversion was developed to generate a random sequence of day-ahead and hour-ahead load and wind forecasts errors for each hourly interval in 2012. The stochastic process was specified using the statistical properties—mean, standard deviation, autocorrelation, and cross-correlation—of the actual day-ahead and hour-ahead load and wind forecast errors. The cross-correlations are composed of the inter-regional correlation of load forecast errors, wind inter-zonal correlations, load-wind correlations and day-ahead and hour-ahead correlations. The statistical properties are derived for four seasons: spring, summer, fall and winter. However, the random process did not include solar forecast errors, although the solar profiles with their actual variability were used to establish the hourly and 5-minute net loads.

The stochastic process was used to generate 100 different day-ahead and hour-ahead load and wind generation forecasts for evaluation of alternative unit commitment and dispatch realizations. These were then used in the process described next.

2.5.2.2 Sequential day-ahead to real-time simulations

The analytical flow of the stochastic, sequential production simulation methodology is depicted in Figure 2-7. The first step in this methodology is the simulation of the day-ahead market with a day-ahead load and wind forecast. The model did not include a day-ahead solar forecast, but rather modeled solar production as a fixed hourly profile. The day-ahead market simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the day-ahead load and wind generation forecast errors described in the previous section. This simulation uses a 24-hour optimization window, with a 24-hour look-ahead to account for long-start units.

The next step in the sequential simulation is the "hour-ahead" simulation which lines up in time with the ISO's hour-ahead scheduling procedure and with the submission of wind schedules in the Participating Intermittent Resource Program. The commitment status for the extremely long- and long-start generators are passed from the day-ahead simulation and frozen in the hour-ahead simulation. As in the case of the day-ahead simulation, the hour-ahead simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the hour-ahead load and wind generation forecast errors. The day-ahead and hour-ahead load and wind generation forecast errors are correlated. This simulation uses a 6-hour optimization window. The hourly unit commitment status for the extremely long-, long-, medium-, and quick-start generators are queried by iteration from the solution and passed to the "real-time" 5-minute simulations, which are described next.

In the real-time simulation unit commitment and dispatch, the resource and network data are the same as that in the day-ahead and hour-ahead simulations. The loads and variable energy resource generation are the "actual" data prior to the introduction of forecast errors, and averaged from the underlying 1-minute data to the 5-minute intervals. The solution is the co-optimization of energy and ancillary services with generation unit commitment and dispatch.

To reduce the computational burden, a selected number of days that exhibited interesting operational challenges were selected for this detailed simulation process to examine the impact on load-following and overgeneration. To identify these days or hours, the ISO undertook a variant on what is called "importance sampling."[48] This is a method for choosing most likely scenarios, or in this case, most likely periods for ramp violations, ancillary service shortfalls, or overgeneration events. The procedure used to identify interesting days for real-time simulations is described in Appendix C-1.

[48] See, e.g., description as applied to the ISO's Transmission Economic Assessment Methodology (TEAM), (2004), pg. 5-8.

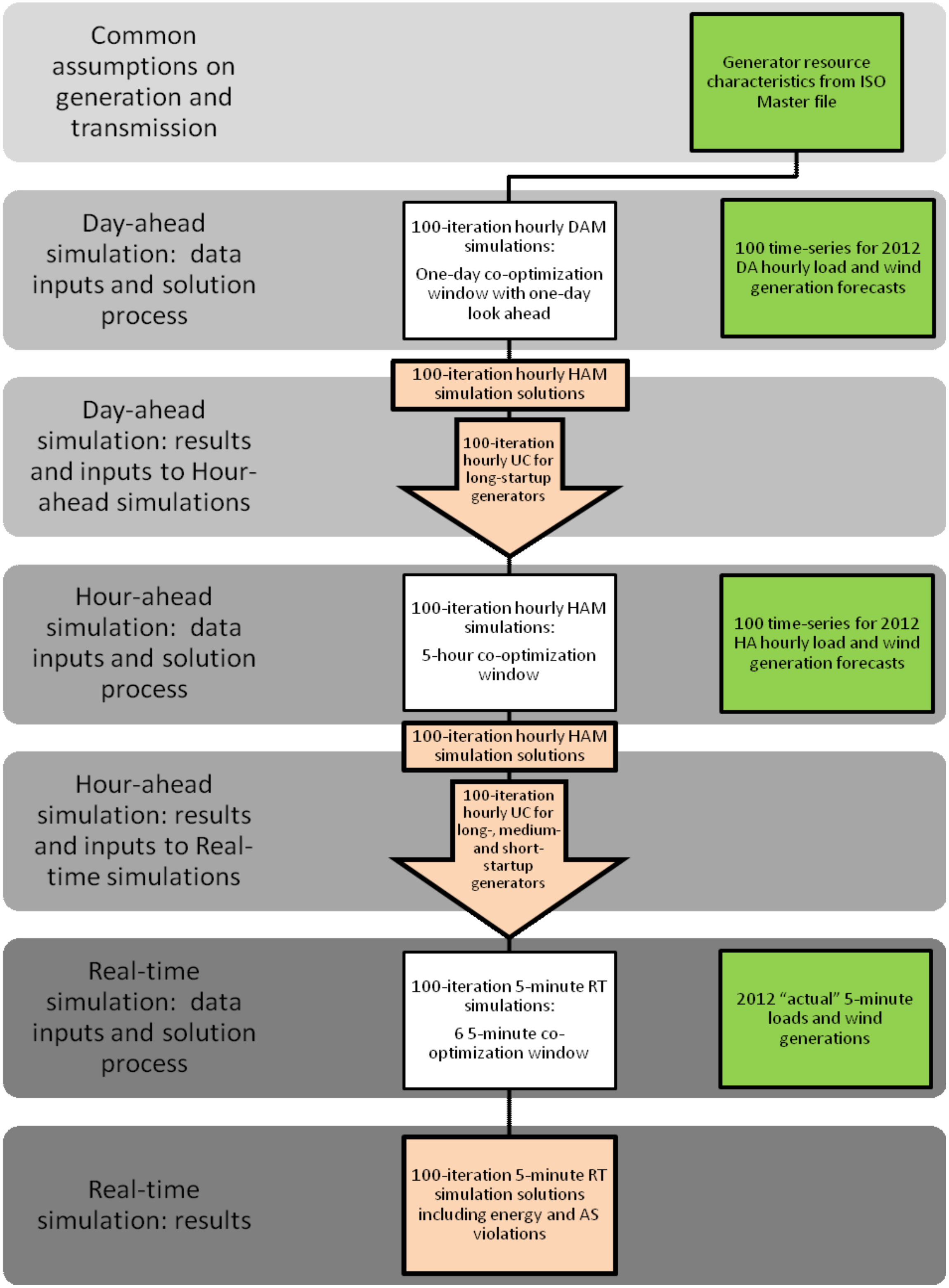

Figure 2-7: Flowchart of the Stochastic, Sequential Production Simulation Methodology

3 Analysis of Operational Requirements

This section and appendices A-1 and A-2 present the updated estimates of operational requirements under a 20 percent RPS, along with a comparison to analogous results from the ISO's 2007 Report and other relevant studies. This section focuses on results from the Summer 2012 simulation; results for other seasons are in Appendix A-1. In addition, Appendix A-2 shows additional sensitivity results for Summer 2012.

The simulation results provide information on a number of operational and market relevant questions, including the simulated seasonal maximum requirements by hour of day[49] and other distribution statistics – average, range (maximum, minimum), frequency of the requirement – over each hour of the season based on different subsets of the simulation results.[50] The seasonal maximum hourly requirement is important information for operational reasons, to provide the ISO with the largest magnitudes of potential requirements. The other statistics are to provide both the ISO and market participants with information about the expected frequency and magnitudes of the operational requirements over the course of each season. This is particularly true for wind production as the input data set to the simulations captures variations in wind production over the entire target year (2012) based on historical production data.

In the 2007 Report, only the seasonal maximum hourly operational requirements by hour of day were reported.[51] At the time, the objective of the analysis was solely to provide results for system operational preparations. In addition, the study used only one wind production profile for the year (based on average capacity factors from historical data), and thus there was concern that additional statistics on the results could be misleading, given that other annual wind profiles could have generated different results, although the maximum requirement results would probably not change substantially.

Moreover, as noted in Section 2.2, the statistical simulations of regulation requirements do not consider the effect of other real-time considerations, such as generator uninstructed deviations in real-time dispatch, as well as day-ahead forecast errors of wind and solar production that could affect day-ahead procurement of regulation and possibly other ancillary services at higher levels of variable energy production. Currently the ISO procures a minimum of 300 MW of Regulation Up and Regulation Down in the day-ahead market to cover peak hour load requirements and those other considerations. The ISO expects that this will remain a minimum requirement, even for hours in which the simulation results shown here suggest a possible "real-time" requirement of less than 300 MW. The ISO believes that the simulation results are a better indicator of the potential need for procurement of above 300 MW of Regulation in certain hours due to forecast

[49] i.e., the maximum seasonal requirement for each hour of the day from the 100 iterations of the simulation of the 90 days of the season

[50] Section 3 describes the results yielded from the 100 iterations of each season. The other statistics are generated from this underlying data set.

[51] See 2007 Report, sections 5.8.3 and 5.10.1 as well as Appendix A; available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

variable energy resource production. Further simulations of different wind production profiles and consideration of other factors, such as day-ahead (rather than hour-ahead) forecast errors, could thus improve understanding of the relationship between operational requirements in real-time and market procurement forecasts day-ahead.

However, the ISO believes that there is market value to providing some of the other statistics on the simulation results. In particular, these additional statistics clarify that the average ± one standard deviation of the simulated values for operational requirements for particular hours of the day over the season can be substantially less than the maximum seasonal requirements for those hours, particularly for the daily peak hours when wind production is typically at a low capacity factor. Moreover, in actual operations, the ISO uses daily and hourly forecasts of load and renewable energy production, and has continuously improved its wind and ramp forecasting capabilities. Hence the ISO will not, in practice, commit resources day-ahead to meet a simulated seasonal maximum operating requirement for a particular hour in which that maximum requirement is not forecast.

As noted in Section 3, the statistical method for calculating these requirements does not evaluate whether the existing generation fleet can meet them. To provide that evaluation, the regulation requirements presented in this section are then compared in Section 4 with historical ISO procurement of regulation and are also explicitly incorporated into the production simulations to further test the capability of the generation fleet to meet them. The load-following requirements are also compared in Section 4 to ISO historical data, but are not explicitly incorporated into the production simulations, which instead attempt to replicate load-following for selected days by conducting sequential day-ahead to real-time unit commitment and dispatch simulations.

Organization of results

The discussion of the simulated load-following and regulation requirements is organized into three categories of results that are found in this section and appendices A-1 and A-2:

1. Portfolio results with all forecast errors, in which the analysis is of the combined wind and solar portfolio and there is no evaluation of changes in forecast error [Section 4 and Appendix A-1];

2. Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio [Appendix A-2]; and the

3. Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors [Appendix A-2].

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the reference year. Like the 2007 Report, the results reported in the following tables and figures as maximums are the 95th percentile occurrence for a particular hour.[52]

3.1 Summary of Findings

The simulation results are summarized as follows.

Load-following

- The maximum hourly simulated load-following up and load-following down capacity requirements in 2012 are 3737 MW and -3962 MW, respectively, compared to 3140 MW and -3365 MW for simulated 2006 levels.

- The maximum hourly simulated load-following up and load-following down ramp rates in 2012 are forecast as 194 MW/min and -198 MW/min, respectively, compared to 166 MW/min and -158 MW/min, respectively, for simulated 2006 levels.

- Because most of the renewable production being modeled in 2012 is from wind resources, they are the primary cause of the increased load-following requirements; at the levels modeled, solar resources only slightly alter the load-following requirements in the morning ramp up hours and evening ramp down hours. Obviously, wind is the sole contributor to the incremental load-following requirements in the night-time hours.

- The largest changes in load-following up capacity are in hours 8-9, corresponding to the morning wind ramp down. The changes in load-following down capacity are less concentrated in particular hours, but the average requirements increase in the hours 6-8 corresponding to the morning solar ramp up and the late afternoon or early evening hours, corresponding in part to the wind ramp up. Seasonal results differ, as shown in Appendix A-1.

- The maximum requirements will not be needed in all hours; for example, the percentage increase in aggregate load-following capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 20 percent for load-following up and 23 percent for load-following down.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, in some of those hours the combination of the two resources slightly reduces the load-following requirements compared to wind resources alone (see Appendix A-2).

[52] That is, excluding the 5 percent highest results from the simulations.

- The effect of forecast error (load, wind and solar) on the load-following requirement is approximately four times the effect of the inherent variability of load, wind and solar (see Appendix A-2).

Regulation

- The maximum hourly simulated Regulation Up and Regulation Down capacity requirements in 2012 are 502 MW and -763 MW, respectively, compared to 278 MW and -440 MW for simulated 2006 levels.

- The maximum hourly simulated Regulation Up and Regulation Down ramp rates in 2012 are 122 MW/min and -97 MW/min, respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

- However, these requirements will not be needed in all hours; for example, the percentage change in aggregate regulation capacity requirements between the 2012 and 2006 simulations of the summer season is estimated at 43 percent for regulation up and 12 percent for regulation down. An important caveat is that there are drivers of regulation procurement not considered in the simulation; however, the changes in the procurement between the two cases are indicative of future increases of procurement.

- The incremental requirements due to solar are greater during the peak hours of the day than those due to wind, due to the greater production of solar energy in those peak hours. Obviously, wind is the sole contributor to the incremental regulation requirements in the off-peak hours.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, the combination of the two resources slightly reduces the regulation requirements compared to wind resources alone.

3.2 Comparison of Seasonal Results

The seasonal maximum results across all hours from the operational requirements simulations for all four seasons are shown in Table 3.1 and Table 3.2, with a comparison of the base-year simulation result (2006), the 20 percent RPS result (2012), and a 33 percent portfolio RPS (2020) result.[53] The remainder of Section 3 focuses on detailed results for one season: summer. The corresponding results for all seasons are found in

[53] The 33 percent RPS result is from one of the renewable portfolios being studied by the ISO and other entities in a subsequent operational study. The particular portfolio is the CPUC's 2009 "Reference Case" portfolio, which includes an additional 9,700 MW of solar resources (PV and solar thermal) and an additional 8,350 MW of wind resources over the base case. Thirty-three (33) percent RPS portfolios with other technology mixes will produce different results. For the source portfolio, see http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

Appendix A-1. Before turning to the summer results, a brief discussion is provided here on seasonal differences and their implications for operational requirements.

As shown in Sections 1 and 2, the typical production profiles for variable energy resources, particularly wind, as well as load profiles vary by season, and the simulation results reflect the differences in average seasonal production and actual variability. Appendix A-1 shows the seasonal results side by side. With respect to load-following, the simulations show higher results in the summer than in the lower load seasons. However, this increase is due more to load variability and forecast error than to changes in the variability and forecast errors associated with the renewable resources.

For regulation up, spring has the highest hourly seasonal maximum value in hour 18. The daily maximums for regulation up tend to be at different times in the different seasons, although all seasons have high values in hour 6 and 18, generally corresponding to the morning wind ramp down and the afternoon solar ramp down. For regulation down, the summer season provides the highest seasonal maximum value in hour 18; however, all seasons have spikes in the regulation down requirement in hour 18. These results are due to the higher wind production in the spring months.

Table 3.1: Change in Simulated Maximum Regulation and Load-Following Capacity (MW) Requirements by Season

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Up Requirement (MW)	277	502	1135	278	455	1444	275	428	1308	274	474	1286
Max Regulation Down Requirement (MW)	-382	-569	-1,097	-434	-763	-1,034	-440	-515	-1,264	-353	-442	-1076
Max Load-following Up Requirement (MW)	2,292	3,207	4,423	3,140	3,737	4,841	2,680	3,326	4,565	2,624	3,063	4,880
Max Load-following Down Requirement (MW)	-2,246	-3,275	-5,283	-3,365	-3,962	-5,235	-2,509	-3,247	-5,579	-2,424	-3,094	-5,176

Table 3.2: Change in Simulated Maximum Regulation and Load-Following Ramp Rate (MW/Min) Requirements

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Ramp Up Rate (MW)	67	122	447	75	118	528	70	114	472	73	107	344
Max Regulation Ramp Down Rate (MW)	-66	-90	-310	-76	-97	-300	-72	-90	-301	-79	-90	-303
Max Load-following Ramp Up Rate (MW)	150	168	325	166	194	313	147	181	324	143	165	296
Max Load-following Ramp Down Rate (MW)	-138	-162	-451	-145	-169	-434	-134	-167	-438	-158	-198	-427

Table 3.3 shows the percentage increase between 2012 and 2006 in the total simulated requirements for load-following and regulation capacity requirements.

Table 3.3: 2012 vs. 2006, Percentage Increase in Total Simulated Operational Capacity Requirements

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

3.3 *Load-following Requirements for Summer 2012*

This section shows the simulation results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical experience.

As described in Section 2, load-following capacity in the statistical simulation is defined as the largest deviation between the hourly schedule and any 5-minute interval schedule within the hour. Figures Figure 3-1 and Figure 3-2 show distribution statistics for the set of values that include the *maximum* load-following capacity result for each hour in the season drawn from all 100 iterations of the simulation. The hourly bars are a modification of a typical "stock" chart. The colored line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars show the results of the 2012 simulation, while blue bars show the 2006 simulation.

The subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days.[54] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low production are on average shown to have smaller impacts on the simulated requirements than hours with high production. That is, the results reflect that, e.g., a 10 percent hour-ahead forecast error on wind production at 6000 MW in one Hour 14 results in a higher load-following requirement than a 10 percent error on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season.

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.[55]

As shown in the figures, the maximum seasonal hourly load-following up requirement (for summer 2012) is 3737 MW (Hour 15), which is an 854 MW increase over the requirement estimated for that hour in the 2006 simulation. The maximum seasonal hourly load-following down requirement for 2012 is 3,962 MW (Hour 24), a 597 MW increase over the requirement estimated for that hour in the 2006 simulation. These maximum increases in requirements are almost entirely driven by the additional wind on the system (some further analysis into the relative impact of load, wind and solar is shown in Appendix A-2).

The figures show that the maximum load-following up and down capacity requirements in 2012, and the biggest changes from the 2006 results, are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 load-following up hours are in hours 8, 14, 15 and 16; the maximums for load-following down are in hours 18, 19, 23 and 24. Notably, the highest average values for load-following requirements in both the upwards and downwards directions are in hours 22-24, corresponding to maximum wind production, showing that it is in these hours that the requirements will increase most substantially overall over the season. This can be seen from the red bars corresponding to those hours in Figure 3-1 and Figure 3-2.

[54] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, day 1, hour 2, … day 2, hour 1, day 2, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[55] The range shown in each red arrow is the minimum and maximum of the *highest* hourly seasonal values for each of the 100 iterations in the simulation. The maximum is thus the highest of those values.

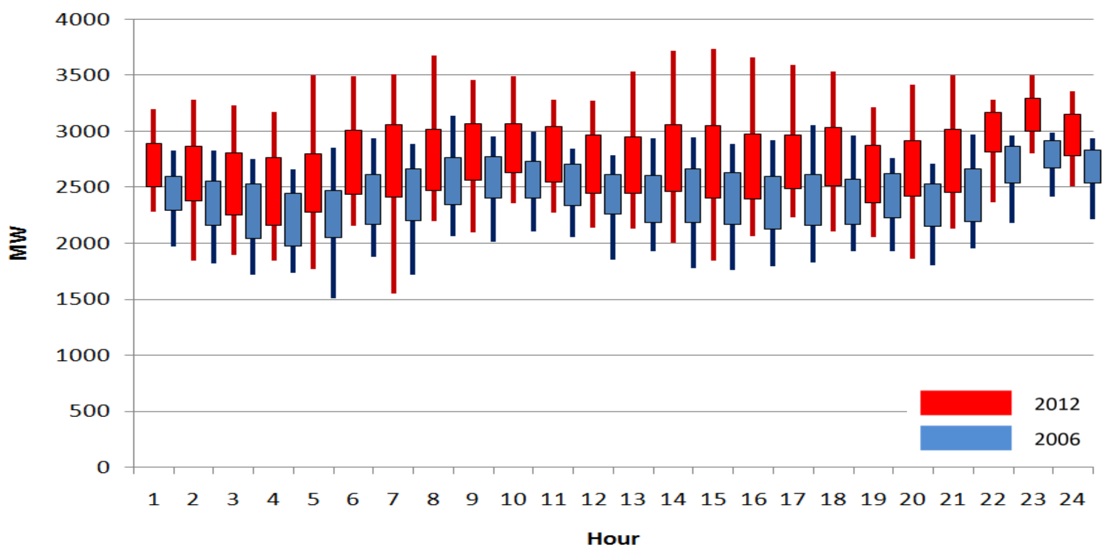

Figure 3-1: Load-following Up Capacity by Hour, Summer (2006 and 2012)

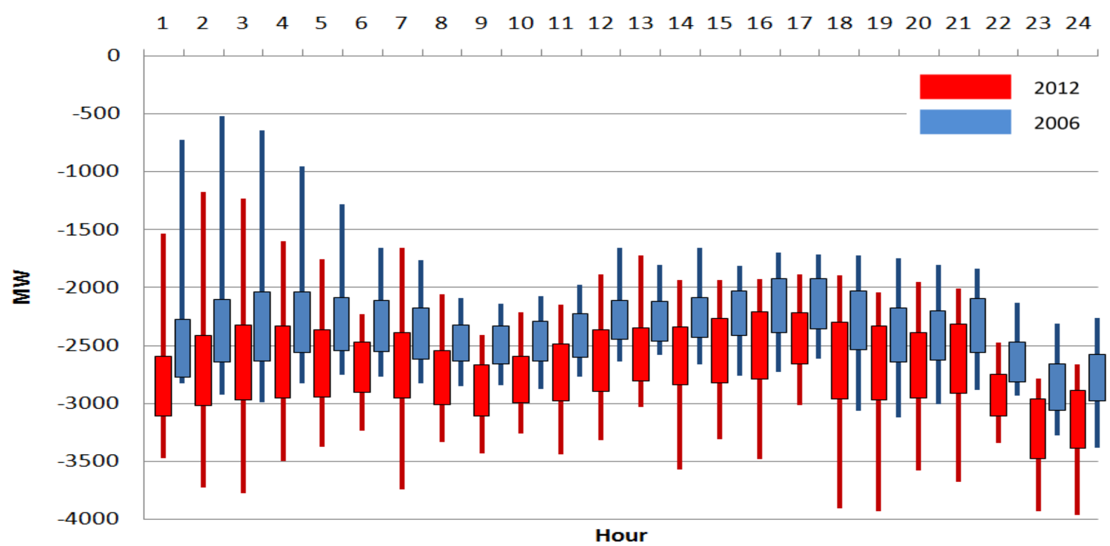

Figure 3-2: Load-following Down Capacity by Hour, Summer (2006 and 2012)

Figure 3-3 and Figure 3-4 show the frequency distribution of the maximum load-following capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[56] These figures show more explicitly that the highest seasonal load-following capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of load-following up in 2012 (the total MW of the values in the frequency distribution) is about 12 percent greater than the corresponding total for 2006; the simulated requirement for load-following down in 2012 is 14 percent greater than that

[56] This frequency distribution is drawn from the same data shown in Figure 3-1 and 3-2.

for 2006.[57] This provides a measure of the increasing volume of the real-time market between the baseline and the target year.

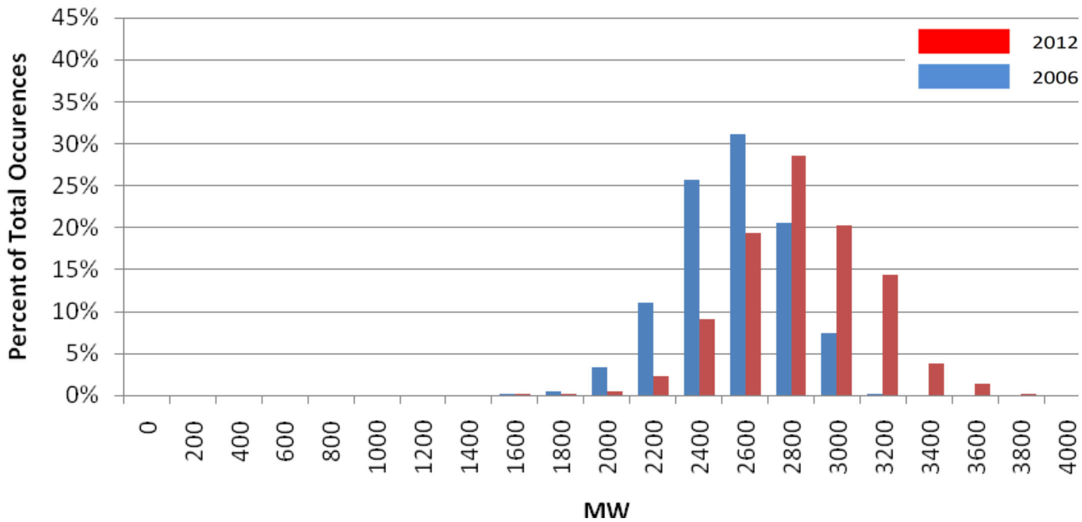

Figure 3-3: Frequency Distribution of Load-following Up Capacity Requirements, Summer (2006 and 2012)

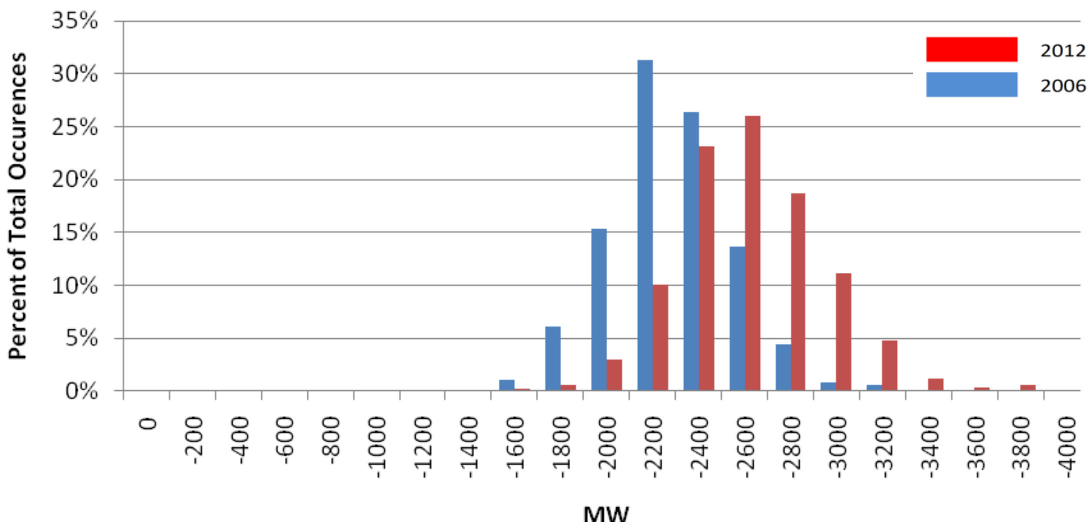

Figure 3-4: Frequency Distribution of Load-following Down Capacity Requirements, Summer (2006 and 2012)

[57] That is, the total MW calculated as "load-following" capacity for each hour in the 2012 simulations divided by the total MW calculated for 2006.

As discussed in Section 2, the simulated load-following *ramp rate* is defined as the maximum increase or decrease in the estimated capacity requirement between any two contiguous 5-minute intervals within the hour being simulated. Figure 3-5 shows that the maximum load-following up ramp rates across the season for the full portfolio are located in the off-peak hours, where they correspond to variability and forecast error in wind production.

Figure 3-6 shows that the maximum requirements in load-following down ramp rate occur between Hour 7 and Hour 10, when solar production ramps up and wind production is decreasing. Again, the actual system net ramp rate can be high in these hours when the wind and solar ramps are not well correlated with the morning load ramp up.

In the high load-following ramp hours, the duration of the ramps may be sustained for a large number of intervals. The statistical methodology tracks duration of the simulated ramp rate using a specialized algorithm (see Section 2).[58] Figures 3-7 and 3-8 show the ramp requirement by minute (MW/min) plotted for the longest number of minute intervals that the algorithm identified in the morning and evening hours, respectively. As shown in Figure 3-7, the upward ramp duration in the morning is required for approximately 30 minutes (as shown on the figure's x-axis), while the downward ramp will be required for approximately 20 minutes. Resources on dispatch should be able to ramp up at a rate of about 100 MW/min. (as shown on the figure's x-axis) for most of the 30 minutes. Similarly, in the downward direction, the resources on dispatch should be able to ramp down at a rate of approximately -175 MW/min. for at least 20 minutes. Figure 3-8 can be interpreted similarly for the evening ramps, in which the ramp duration and magnitudes are roughly reversed compared to the morning hours.

[58] Called the "swinging door" algorithm, which tracks and measures sequences of random draws to infer changes in ramp rates and durations.

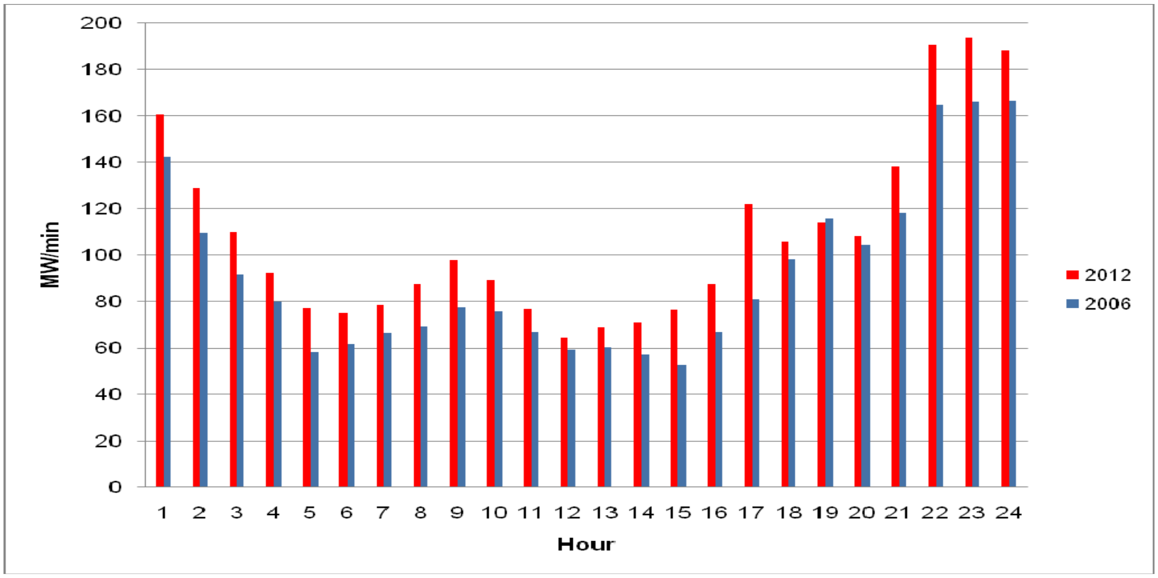

Figure 3-5: Load-following Up Ramp Rate, Summer (2006 and 2012)

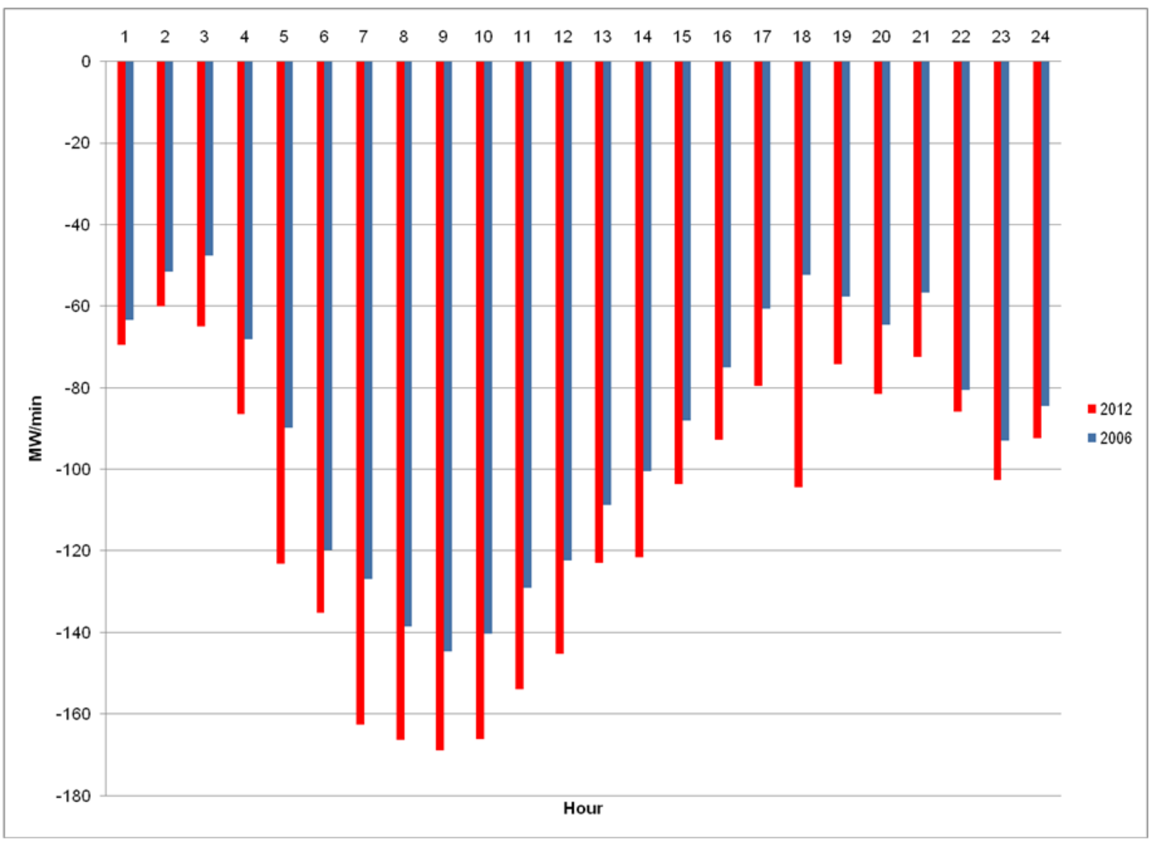

Figure 3-6: Load-following Down Ramp Rate, Summer (2006 and 2012)

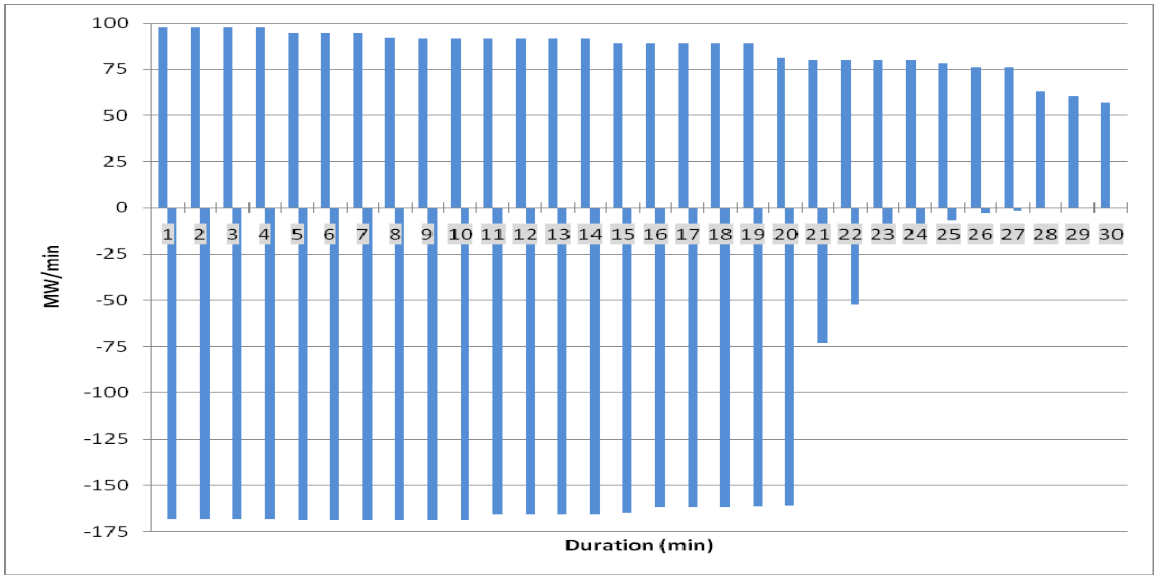

Figure 3-7: Seasonal Load-following Up and Down Ramp Duration for Morning Hours, Summer 2012

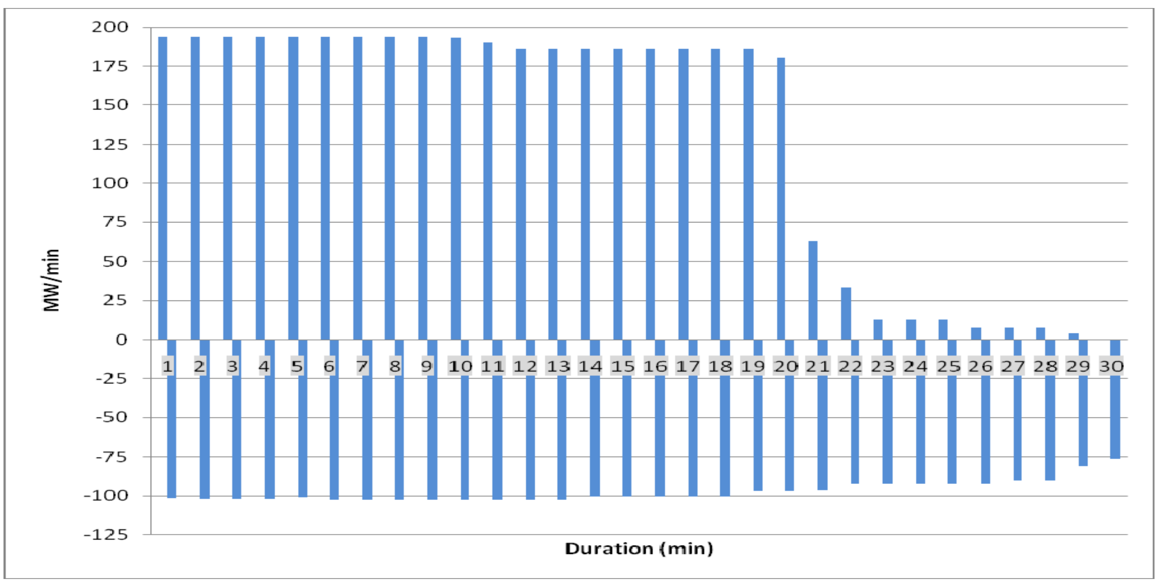

Figure 3-8: Seasonal Load-following Up and Down Ramp Duration for Evening Hours, Summer 2012

In general, the maximum simulated load-following capacity and ramp requirements increase substantially for almost every hour of the day. Section 4 compares the load-following requirements determined here with the historical load-following capability. Section 5 simulates the capability of the fleet to meet the load-following requirements in 2012 under different conditions.

3.4 Regulation Requirements for Summer 2012

This section shows the simulated regulation requirement results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical results. The results presented here are organized in parallel to the results shown for load-following, with some differences noted. Figures Figure 3-9 and Figure 3-10 show distribution statistics for the set of values that include the *maximum* regulation capacity result for each hour in the season drawn from all 100 iterations of the simulation. As with the load-following results, the hourly bars are a modification of a typical "stock" chart. The black line represents the range (minimum, maximum) of the results and the red box shows the standard deviation. The arrow points towards the maximum of the range. The maximum of the baseline 2006 simulation for each hour is shown in blue.

As with the load-following results, the subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days.[59] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low (or no) production are on average shown to have smaller impacts on the simulated regulation requirements than hours with high production.[60]

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.

The figures show that similarly to load-following, the incremental regulation capacity requirements are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 regulation up hourly requirements are in hours 9, 8, 6 and 19; the maximums for regulation down are in hours 15-18. Solar production variability has the strongest effect on the simulated regulation up requirements in the late afternoon hours, while also having a strong effect on the regulation down requirements in Hour 8 (see figures in Appendix A-2). Wind production variability is the predominant driver of the increased requirements in the other hours. In particular, the spike in regulation down requirements in Hour 18 is due to the consistent fast ramp in wind production in that hour found in the underlying wind production data set for 2012.

[59] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[60] That is, the regulation results reflect that, e.g., variability on wind production at 6000 MW in one Hour 14 results in a higher regulation requirement than variability on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season, as modeled.

Notably, the distribution statistics show that not only the maximums for regulation up are in the mid-morning hours, but also the highest averages. These hours correspond to the maximum wind ramp down periods, showing that it is in these hours that the requirements will increase most substantially overall. Similarly, not only the maximums but also the average increase in regulation down requirements take place in the late afternoon hours.

In a few hours of the regulation down results, the simulation with the incremental wind and solar shows a lower maximum result than the 2006 simulation. This result is due to the correlation of wind, solar and load in those hours, which has the effect of lowering the regulation requirement. For example, in the early morning, load is ramping up, while wind is ramping down and solar is ramping up. The net effect can be very little downward requirements in the regulation time frame. However, as noted above, the ISO typically procures a minimum quantity of 300 MW of regulation up and 300 MW of regulation down in the day-ahead time frame to account for uncertainties that are not captured in the simulation.

As noted above, the maximums are not an indication of the change in regulation procurement across all hours and all system conditions. Figures Figure 3-11 and Figure 3-12 show the frequency distribution of the maximum regulation capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[61] These figures show more explicitly that the highest seasonal regulation capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of regulation up in 2012 (the total MW of the values plotted in the frequency distribution for 2012) is approximately 37 percent greater than the corresponding total for 2006; the simulated requirement for regulation down in 2012 is only 11 percent greater than that for 2006, and much of that increase is concentrated in one or two late afternoon hours.[62] This provides a measure of the possible increasing aggregate procurement of regulation between the baseline and the target year.

[61] This frequency distribution is drawn from the same data shown in Figure 3-9 and Figure 3-10.

[62] That is, the total MW calculated as “load-following” capacity in the 2012 simulations divided by the total MW calculated for 2006.

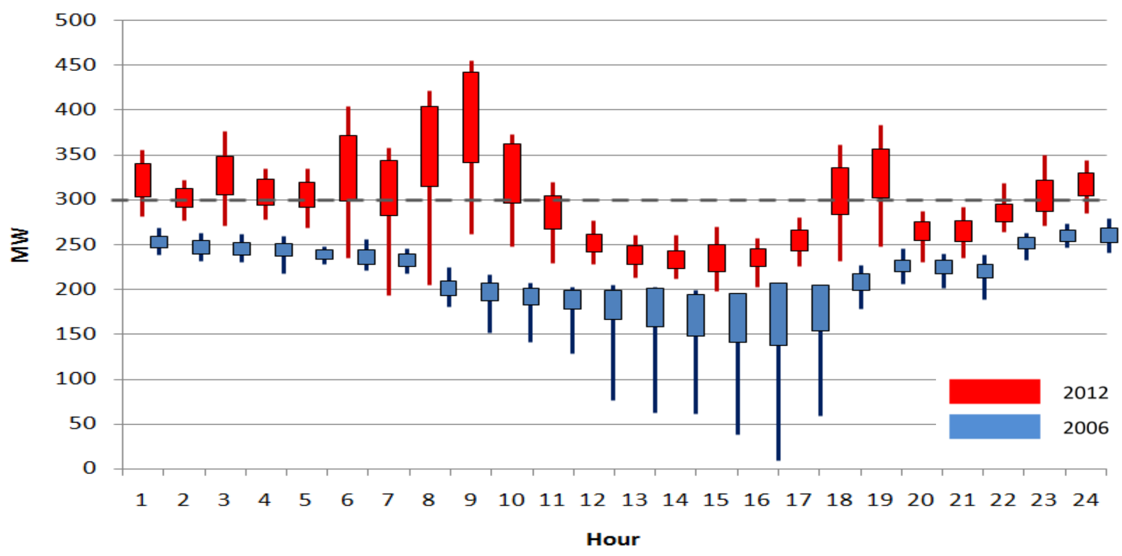

Figure 3-9: Regulation Up Capacity Requirement by Hour, Summer (2006 and 2012)

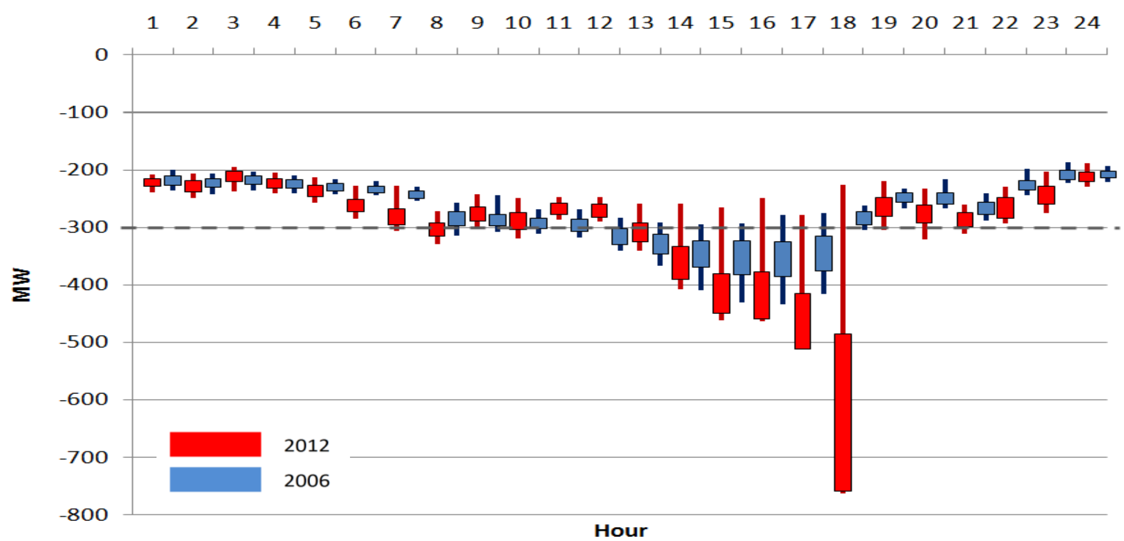

Figure 3-10: Regulation Down Capacity Requirement by Hour, Summer (2006 and 2012)

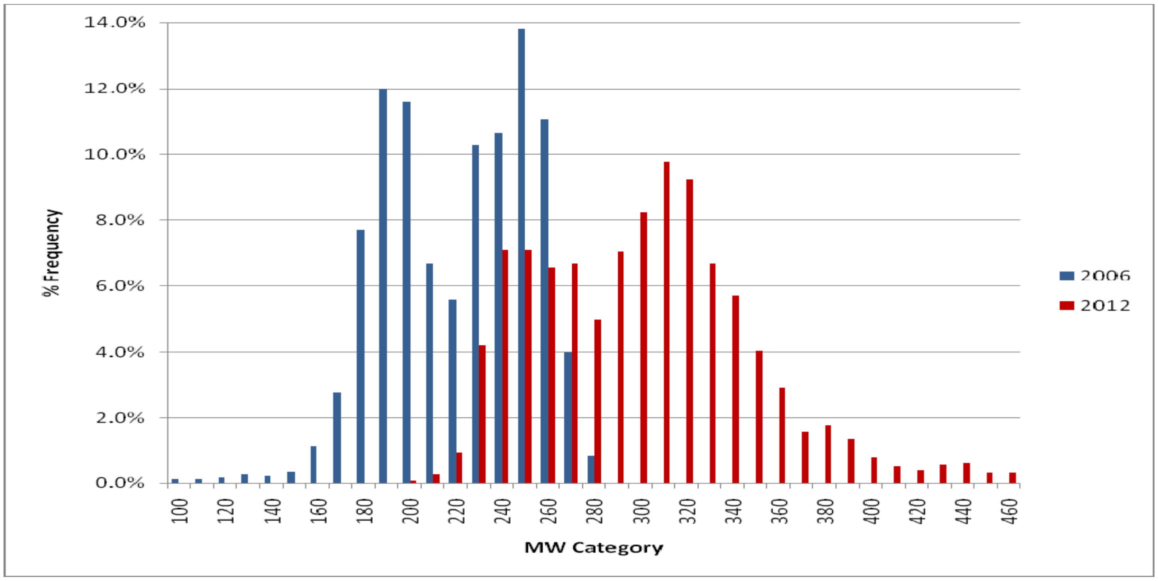

Figure 3-11: Frequency Distribution of Regulation Up Capacity Requirements, Summer (2006 and 2012)

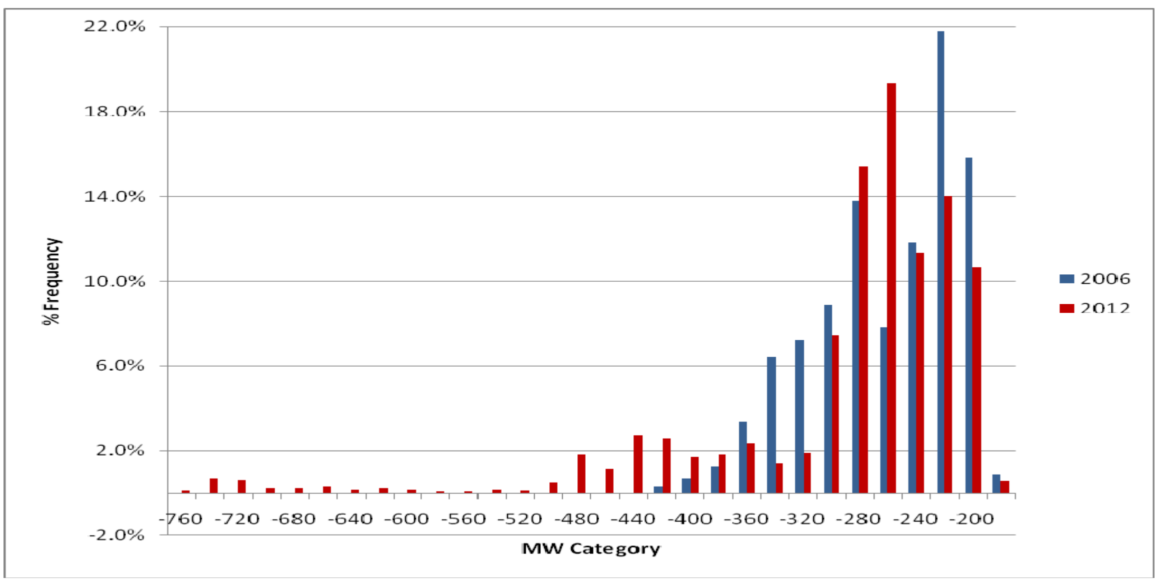

Figure 3-12: Frequency Distribution of Regulation Down Capacity Requirements, Summer (2006 and 2012)

As discussed in Section 2, the simulated regulation *ramp rate* is defined as the largest minute-to-minute change within a 5-minute dispatch interval. Figure 3-13 shows that the maximum regulation up ramp rates across the season (for the full portfolio) are located in the afternoon hours. Figure 3-14 shows that the maximum requirements in regulation down ramp rate occur between Hour 6 and Hour 9, when solar production ramps up and wind production is decreasing, and again in the late afternoon in Hours 16 to 18.

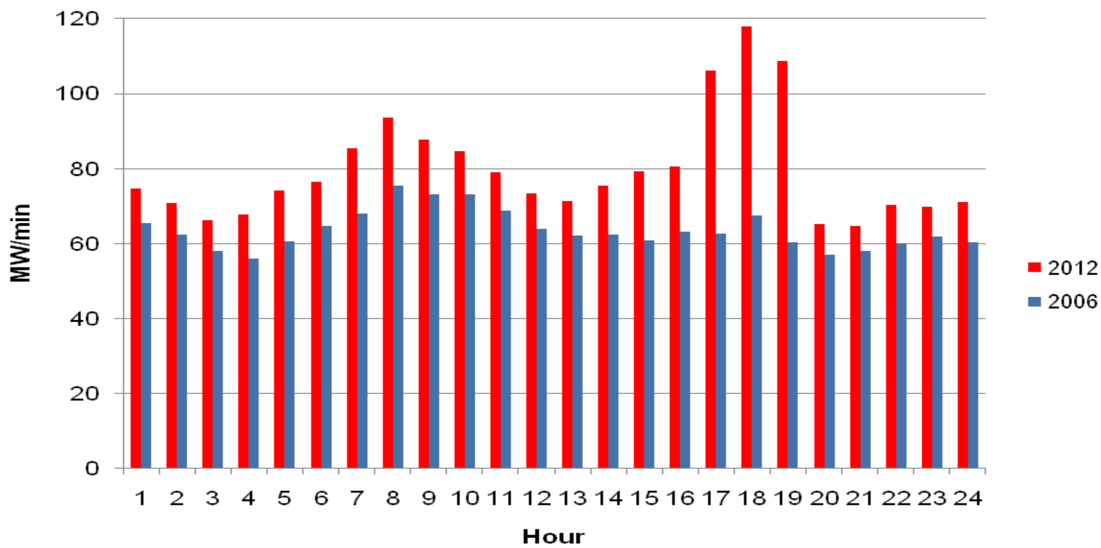

Figure 3-13: Summer Regulation Up Ramp Rate by Hour (2006 and 2012

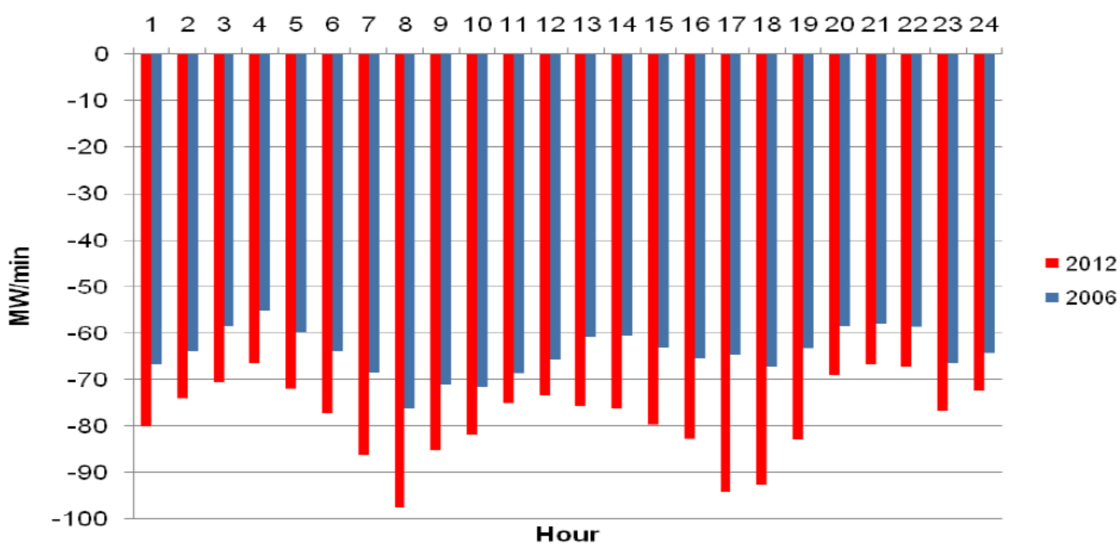

Figure 3-14: Summer Regulation Down Ramp Rate by Hour: 2006 and 2012

4 Analysis of Historical Fleet Capability

This section presents analysis of selected measures of generation fleet capability for the period from April 1, 2009 to June 30, 2010. The objective is to provide insight into the ability of the current generation fleet to provide sufficient regulation and load-following capacity to meet the operational requirements under 20 percent RPS determined in Section 3. Section 4.1 provides a summary of the findings of this analysis. Section 4.2 presents an inventory of the physical characteristics of the ISO generation fleet. Section 4.3 compares historical, seasonal load-following capacity with the corresponding requirements discussed in Section 3.3. Similarly, Section 4.4 compares historical, seasonal bid-in and committed regulation capacity with the additional regulation capacity requirements discussed in Section 3.4.

4.1 Summary of Findings

- The historical 5-minute load-following capability of the generation fleet, defined as the upward and downward ramp capability in each 5-minute interval, has been measured from April 1, 2009, to June 30, 2010. This analysis shows that the fleet inherently has the 5-minute load-following capability required under 20 percent RPS. However, much of the downward capability is currently provided to the ISO with limited inflexibly due to submitted self-schedules. To successfully integrate 20 percent RPS, the level of self-schedules will have to decrease.

- The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced at the 20 percent RPS.

- In addition, the 5-minute regulation capability of the generation resources bid-in and committed in each hour of the day since April 1, 2009, has been measured and shown potentially to be the source in most hours of sufficient capability over and above the calculated additional regulation requirements under 20 percent RPS.

4.2 Physical Characteristics of the Existing Generation Fleet

Table 2.7 in Section 2 provides a breakdown of the generation fleet capacity organized by ramp rate segment (MW/min). For example, there is a total of 21,003 MW of capacity under the ISO's control with a ramp rate of 5 to 10 MW/min. Individual generation units will have different ramp rates over their range of output, so may have capacity in several of the columns. The table also divides the generation fleet into once-through cooling (OTC) units and those that are not once-through cooling units. Although replacement and repowering of once-through cooling units will begin after the study date of 2012, the table helps to characterize the flexibility characteristics of those units, which must be considered in the context of renewable integration capabilities.

4.3 Load-following Capability

Physical characteristics give important insight into fleet capabilities, but operational flexibility is a function of which units are committed in each time interval and also their availability for dispatch. Generation that is self-scheduled at levels greater than a resource's physical minimum operating level (Pmin) through the ISO markets is essentially unavailable to ISO dispatchers within the hour except through non-market dispatch instructions that can distort market prices. To gain insight into the historical upward and downward capability of the committed resources, the ISO has examined the resources on the system from April 1, 2009 - June 30, 2010, to quantify both their load-following and regulation capability.

This section discusses load-following capability for the summer season. The examination for the remaining seasons can be found in Appendix B. Figure 4-1 provides the 5-minute Load-following up capability, measured as the maximum dispatch that can be achieved in the upward direction based on submitted energy bids within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. Figure 4-2 provides the 5-minute load-following down capability, limited by self-schedule, measured as the maximum dispatch that can be achieved in the downward direction within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. As used throughout this report, the stock charts show the range and standard deviation of the upward and downward 5-minute load-following capability. The upper and lower dispatch limit are internally calculated and reflect a resource's ramping capability, operating limits, derates, regulation limits (when on regulation). The load-following capability is a measure of the capability to follow load from one 5-minute dispatch to the next.

The results show that the ISO dispatch in recent months appears on average to meet the expected load-following upwards capability for even the extreme ramps reflected in the statistical simulations. The simulated *maximum* load-following up ramp rate for summer in 2012 as shown in Table 3-2 was 194 MW/min, which is 980 MW/5 min. From Figure 3-5 in Section 3, it can be observed that the high ramps are during hours 22 through 24. The historical summer 5-minute load-following capability in 2009-2010 is shown in Figure 4-1. Historically, anywhere between 0 and 3000MW of load-following capacity is available during these hours with an average of approximately 1200MW. Therefore, on an average, based on committed resources with existing solution constraint, sufficient 5-minute load-following capacity would be available to meet the requirements. The production simulation discussed in Section 5 tests the load-following capability of the system for a few selected days in the future.

The results for downwards ramping appear more problematic. The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min as shown in Table 3-2, which is -845 MW/5 min. These high downwards ramps are often in the mid-morning hours as shown in Figure 3.6 in Section 3. As discussed before, Figure 4-2 shows the summer 5-minute load-following down capability of only the units that are dispatchable. Figure 4-3 shows the summer 5-minute load-following down capability of thermal units, both self-scheduled and dispatchable. The 5-minute downward ramp capability without the self-scheduled units, ranges from 0 to -2000MW. During some hours, for example, hour 7 in Figure 4-2, the average 5-minute downward capacity could be as low as -500 MW, which is less that the requirement of -845 MW. The 5-minute downward ramp capability is much higher if the contribution from self-scheduled units is counted. This shows the need for the ISO to pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operational flexibility of other dispatchable resources. The production simulation discussed in Section 5 will specifically test the downward load-following capability of the system for a few selected days when down ramp is expected to be a problem.

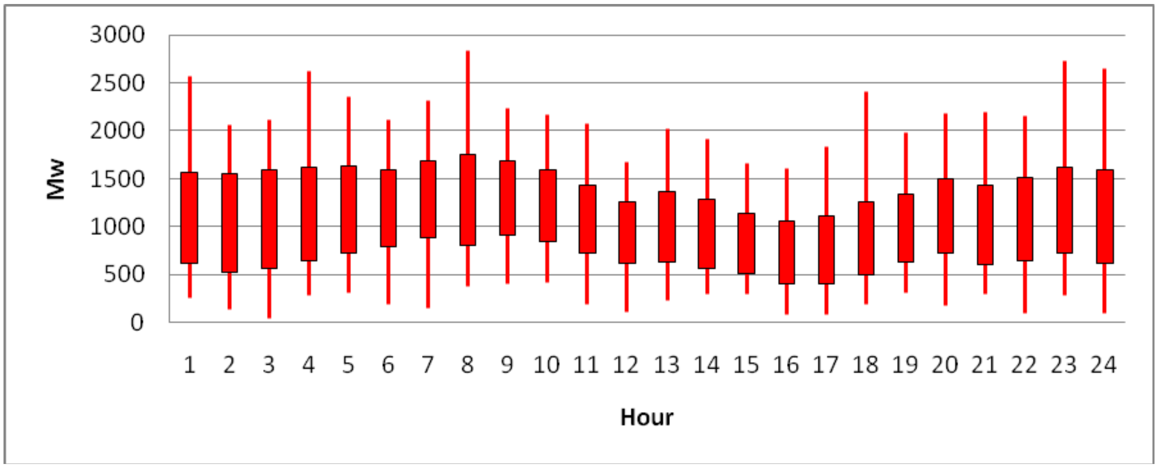

Figure 4-1:Summer Upward 5-minute Capability, 2009 and June 2010

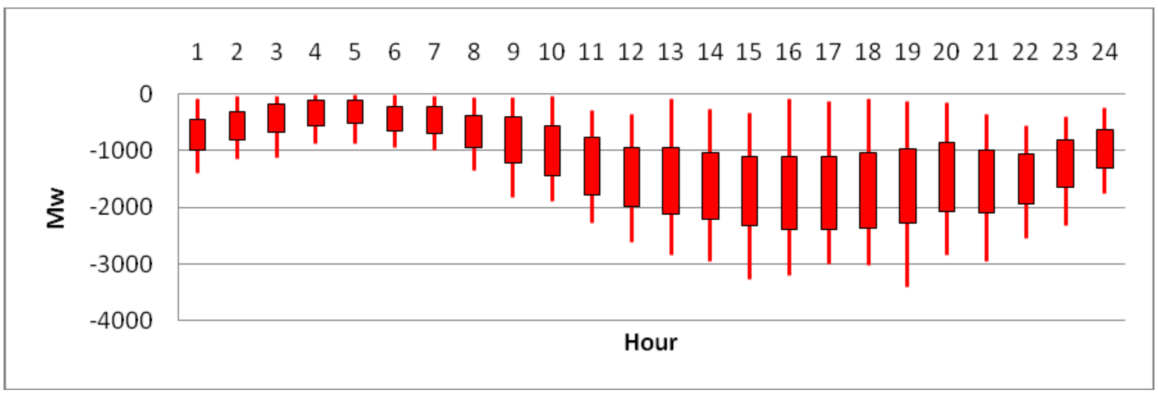

Figure 4-2: Summer Downward 5-minute Capability, limited by self-schedules, 2009 and June 2010

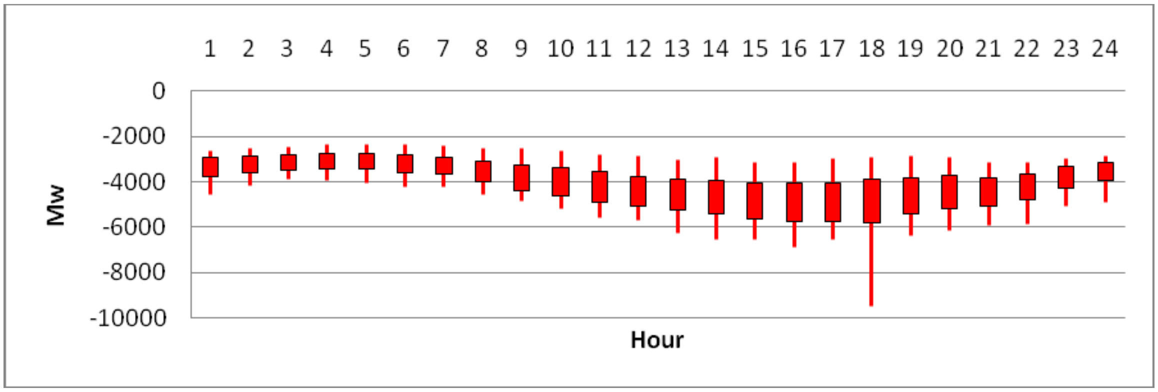

Figure 4-3:Summer Downward 5-minute Capability of Thermal Units, not limited by self-schedules, 2009 and June 2010

The above results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up requirements simulated for 20 percent RPS within 20 minutes or less.[63] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

A further measure of the frequency of downward ramp constraints and overgeneration is the occurrence of negative prices. Table 4.1 shows the number of real time 5-minute dispatch intervals which all Load Aggregation Points (LAP) had negative prices since April 1, 2009 (3,727 intervals in total). The chart shows that the highest frequency is concentrated in the early and mid-morning hours with heaviest occurrence in the spring months.

[63] For example, if the 3,737 MW maximum load-following up requirement determined in Section 3 has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

Table 4.1: Frequency of Negative Prices in Real-Time Dispatch Intervals by Month and Hour, April 1, 2009 to June 30, 2010

	April 1, 2009-March 31, 2010												April 1, 2010-June 30, 2010		
	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)	Jul (Out of 372int/ hr)	Aug (Out of 372int/ hr)	Sep (Out of 360int/ hr)	Oct (Out of 372int/ hr)	Nov (Out of 360int/ hr)	Dec (Out of 372int/ hr)	Jan (Out of 372int/ hr)	Feb (Out of 336int/ hr)	Mar (Out of 372int/ hr)	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)
1	69	40	31	19	6	2	2	4	13	2	3	2	1	5	33
2	26	34	37	14	18	7	0	5	7	10	0	7	1	0	20
3	26	35	85	41	11	19	1	28	9	9	14	10	10	5	20
4	71	64	105	78	22	13	2	8	9	25	23	5	27	4	20
5	58	65	65	72	13	19	1	8	8	7	16	10	22	56	80
6	47	66	67	14	6	8	0	4	2	1	1	10	14	42	66
7	29	75	98	76	7	15	0	7	6	6	0	2	2	61	81
8	74	20	36	21	11	9	3	6	1	0	0	0	5	18	52
9	9	17	33	29	7	2	0	0	0	0	0	0	0	5	49
10	2	14	12	9	3	0	0	0	0	0	0	0	0	6	24
11	15	12	1	0	0	1	0	0	0	0	0	0	0	0	1
12	18	9	0	0	0	0	0	0	0	0	0	0	0	0	3
13	10	6	8	0	0	0	0	0	0	0	0	0	0	0	10
14	6	4	0	0	0	0	0	0	0	0	0	0	0	0	5
15	9	15	0	0	0	0	0	2	0	0	0	0	0	0	0
16	7	12	10	0	0	3	0	1	0	0	0	0	0	2	0
17	13	2	6	0	0	0	0	0	0	0	0	0	0	2	0
18	16	12	11	0	0	0	0	0	0	0	0	0	1	0	0
19	37	3	17	0	0	0	0	0	0	0	0	1	1	2	2
20	29	1	11	0	0	0	0	0	0	0	0	0	4	0	0
21	3	0	4	0	0	0	0	0	0	0	0	0	0	0	0
22	16	5	1	0	0	1	0	0	0	0	0	0	0	0	0
23	77	24	25	3	1	0	0	1	1	0	0	0	0	3	6
24	42	63	36	16	4	4	2	4	7	7	1	0	1	10	11

4.4 Regulation Capability

As one step to evaluate the ability to meet the sustained higher regulation requirements identified in Section 3, the ISO has examined the regulation capability of the fleet as well as regulation procurement quantities and the ranges of regulation capable units under dispatch since the start of the redesigned wholesale markets in April 2009. As shown in Table 4.2, the ISO has substantial regulation capacity, with almost 20,000 MW of regulation certified capacity and over 5,000 MW with regulation ramp rates of 20 MW/min or higher. Regulation deficiency when it occurs is thus primarily due to system conditions that restrict regulation capable units from being on dispatch. Historically, the ISO has been short of regulation down at times, especially during high hydro conditions such as occurred in 2006, which could be exacerbated with additional wind on the system.[64]

Table 4.2: Regulation Certified Capacity of the ISO Generation Fleet by Ramp Rate, 2010

Generation Type		Regulation Ramp Rates (RR) (MW/min) by Category				
		1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle	719	1693	2171	347	4930
	Dynamic Schedule				775	775
	Gas Turbine	20	20	159		199
	Hydro	319	1020	891	1880	4110
	Other				4	4
	Pump/Storage				969	969
	Steam	316	100			416
	Not specified				525	525
Non-OTC Unit Total		1374	2833	3221	4500	11928
OTC units	Combined Cycle		370			370
	Steam	2442	3599	500	1060	7601
OTC Unit total		2442	3969	500	1060	7971
All Units Total		3816	6802	3721	5560	19899

Note: Some capacity numbers are rounded

Given the significant changes in market optimization and bidding incentives inherent in the redesigned markets, the ISO determined not to examine regulation procurement and market conditions prior to April 2009.[65] Since that date, while system conditions have not corresponded to the prior historical periods in which ancillary service bids were insufficient, the ISO has procured regulation up and regulation down quantities above the historical norm of 350 MW for the first few months of the redesigned market to ensure reliability of system operations. This has provided one natural test of the markets' ability

[64] Performance of the regulation down markets in the 2006 high hydro conditions is discussed in California ISO, Department of Market Monitoring, *Annual Report, Market Issues and Performance, 2006*, Chapter 4. Available at http://www.caiso.com/1b7e/1b7e71dc36130.html.

[65] The ISO market now procures all ancillary service requirements in the day-ahead market, where the market model simultaneously co-optimizes offers for energy, regulation and operating reserves. This procedure allows for the most efficient selection of bid-in generation capability to meet market and reliability requirements.

to procure higher levels of regulation capacity in all hours of the day, albeit under the system conditions in April 2009. Regulation procurement has been reduced in more recent months and is currently procured on a variable basis throughout the operating day, reflecting the impact of system conditions on regulation needs. Figure 4-4 shows that the ISO has procured 400 MW or more of both regulation up and regulation down for over 2500 hours from April 1, 2009 – June 30, 2010. Moreover, the maximum MW procurements of 600 MW or more took place in every hour of the operating day, confirming that at least under the conditions of that period, the market could mobilize as much regulation as the operational simulations of 20 percent RPS.

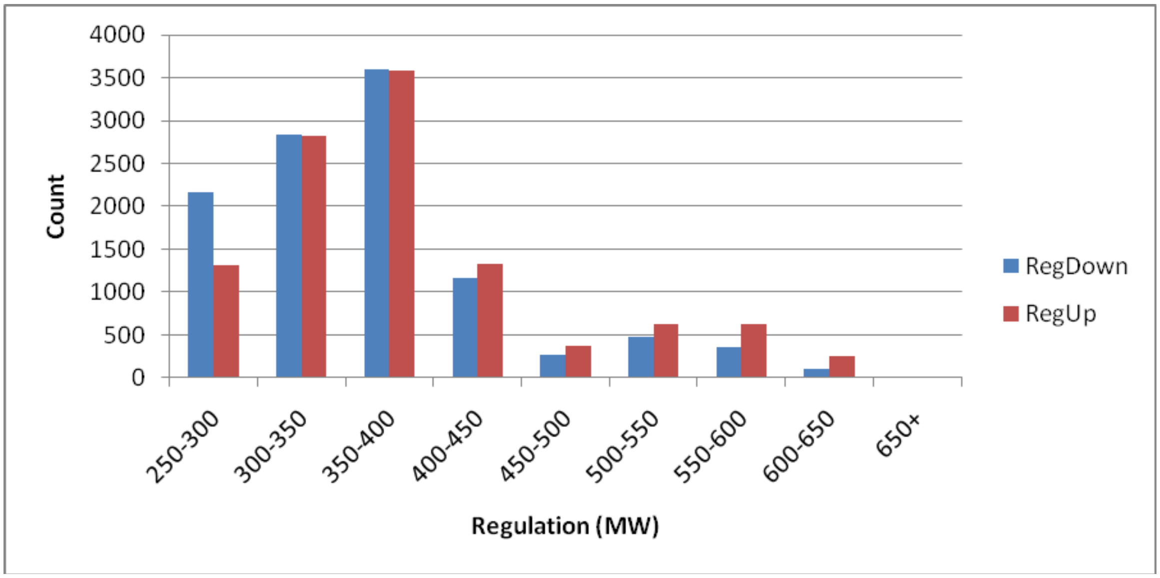

Figure 4-4: Frequency of Regulation procurement by MW (4/1/09 to 6/30/10)

Figure 4-5 and Figure 4-6 show the historical regulation up and down procurement. The values shown are the maximum of the day-ahead and real-time regulation procurements. These figures show that the ISO has been procuring at least 300 MW of regulation during all hours.

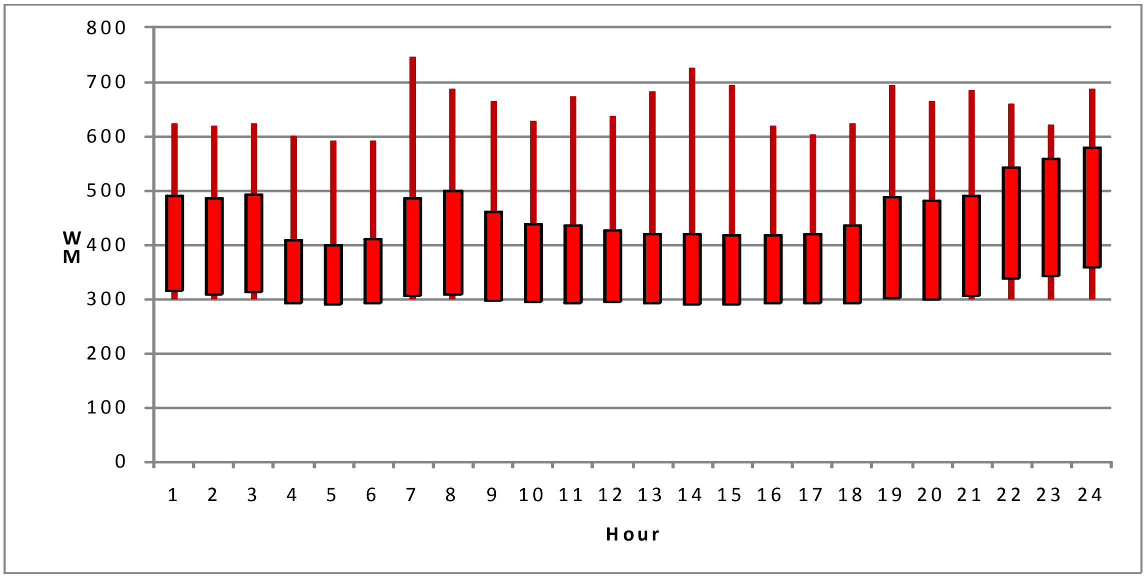

Figure 4-5: Regulation Up Procurement (Max of DA and RTPD Cleared Values)

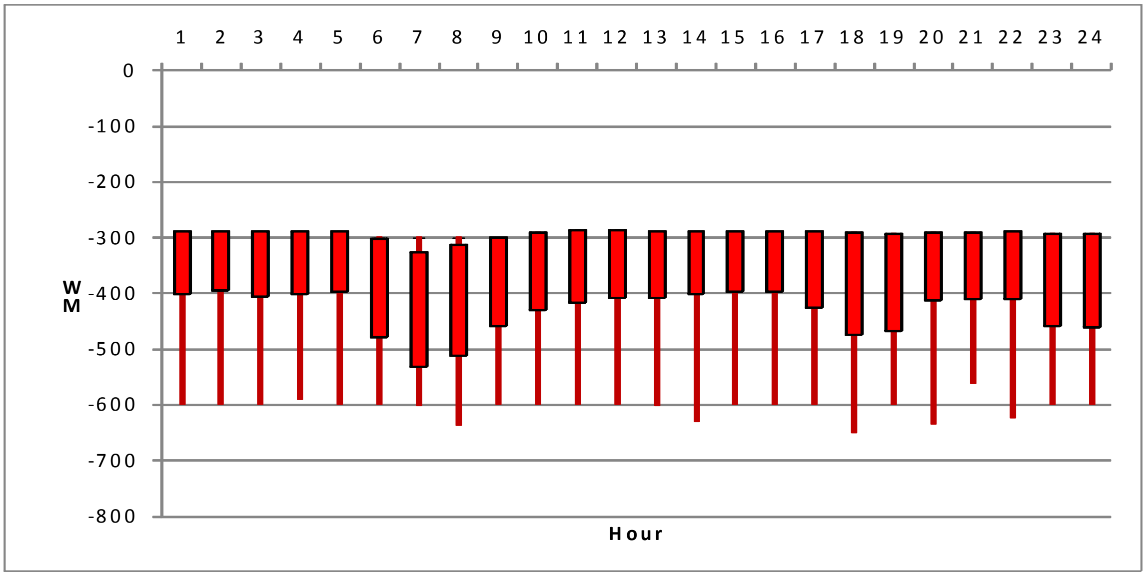

Figure 4-6: Regulation Down Procurement (Max of DA and RTPD Cleared Values)

Moreover, additional analysis of generation that bid into the regulation market, and was committed and dispatched in energy (i.e., on-line) but not necessarily selected to provide regulation, shows that there is a large reservoir of regulation certified capacity available at all hours of the day. When this on-line capacity is constrained to its 5-minute regulation ramp capacity (using the unit-specific regulation ramp rates shown in Table 4.2) there is typically potential coverage of between 1,000 – 2,000 MW of regulation up and regulation down requirement in that 5-minute interval, *if* all such on-line units could provide regulation and do so without creating overgeneration conditions.[66] Moreover, the measurements do not reflect the operational limitations of bid-in capacity due to resource awards of energy or other ancillary services.

This measurement is shown for the summer months in Figures 4-7 and 4-8 and for all seasons in Appendix B. However, particularly in spring and summer, this measure of potential regulation capacity falls below 1000 MW and close to 500 MW in some early morning hours, showing that capability does tighten reflecting fewer regulation capable units on-line.

The combination of the inventory of regulation capacity and ramp rates, the record of sustained regulation procurement at up to 600 MW of regulation up and regulation down, and the empirical analysis of on-line regulation ramp capability suggest that the ISO can meet the higher regulation requirements forecast for 20 percent renewable energy. A further test of the ability of the unit commitment and dispatch to meet the higher regulation requirements is conducted using production simulation that reserves such capacity, as discussed in Section 5. That analysis highlights the potential constraint on regulation down during spring high hydro, light load conditions.

[66] The ISO actually procures regulation based on the resource's 10-minute regulating ramp range. However, this measurement was conducted on a 5-minute basis to provide comparison with the operational simulation results in Section 3. Clearly, if the measurement was for 10-minute ramps, the capability shown here would be roughly doubled.

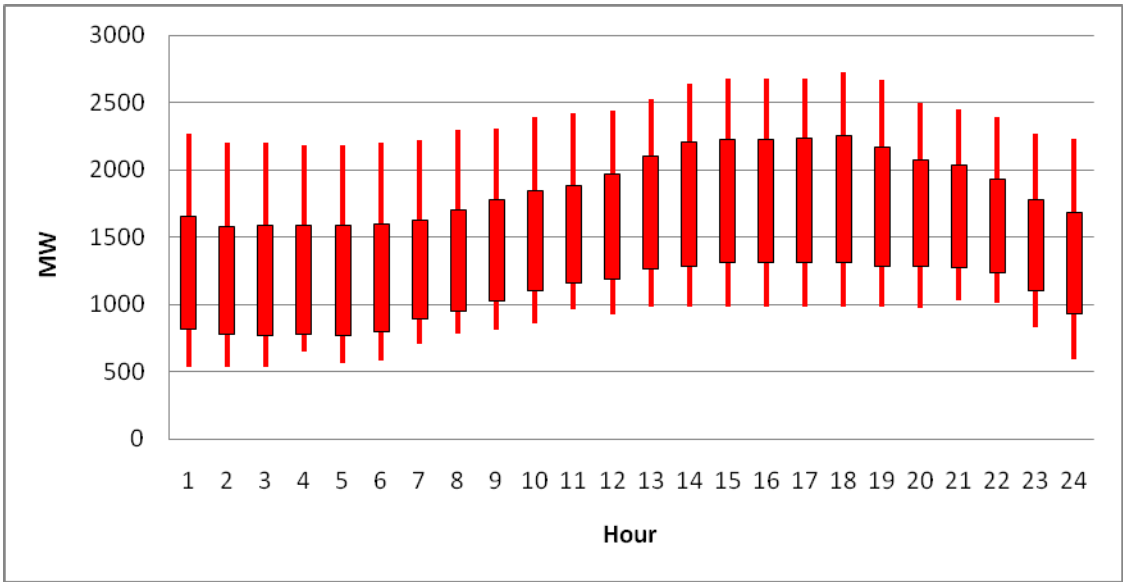

Figure 4-7: Regulation Up 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

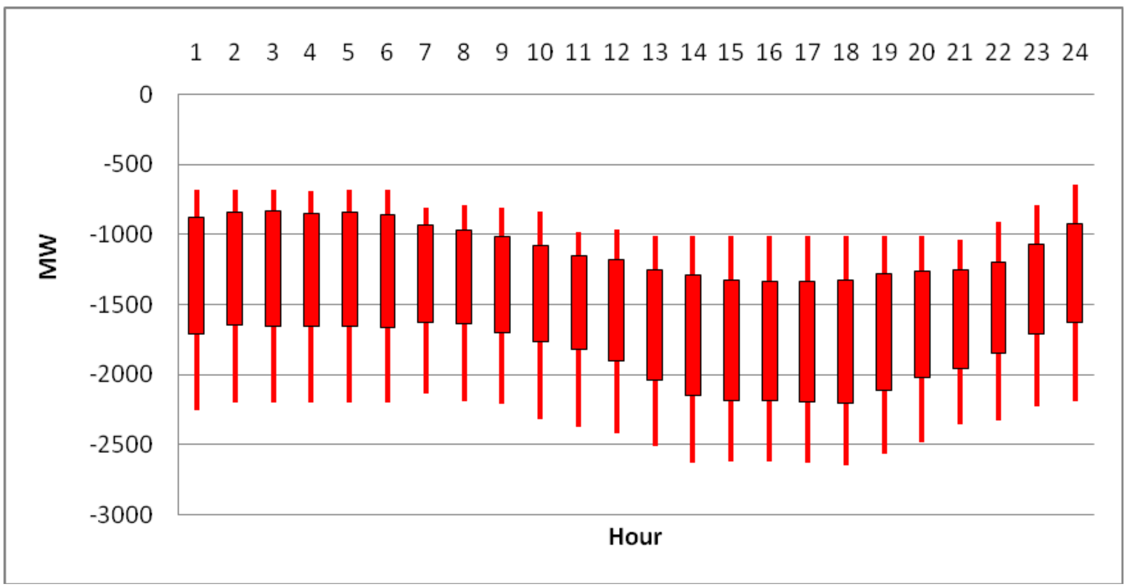

Figure 4-8: Regulation Down 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

5 Analysis of Operational Capability under 20 percent RPS

This section presents the results of the production simulation modeling of the integration of 20 percent renewable energy. Section 5.1 provides a high-level summary of the findings. Sections 5.2 and 5.3 discuss the analysis of load-following and overgeneration impacts, respectively. Section 5.4 provides certain measures of changes in the operation of the thermal generation fleet (e.g., number of starts) as well as preliminary estimates of changes in energy market revenues by unit type.

5.1 Summary of Findings

- Production simulation results suggest that shortages in load-following down capability will result in less than 0.02 percent of renewable energy (approx. 10 GWh) potentially needing to be curtailed. No significant shortages of load-following up or regulation were found.
- Overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. Overgeneration, under the worst-case scenario, which assumes no load growth between 2006 and 2012, was 0.32 percent (150 GWh) of annual energy from renewable resources. There is potential to further relieve these instances of overgeneration by increasing the commitment of dispatchable resources in place of inflexible resources, such as firm imports.
- With the 20 percent RPS, dispatchable generators will start and stop more frequently. In particular, combined cycle generators' starts increase by 35 percent. Also, the energy from the combined cycle units decreases by roughly 9 percent with more reduction occurring during off-peak hours with wind generation, indicating that there will be more cycling in the dispatchable fleet.
- The energy market revenues for all dispatchable thermal units were substantially lower by 2012 due to the compounding effect of lower capacity factors and suppressed energy prices due to the influx of renewable energy.

5.2 Load-following and Regulation Impacts

In general, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. Uncertainty in generation may lead to a unit commitment with inadequate regulation and load-following capability. The shortage of regulation and load-following capability may have an impact on Area Control Error (ACE), and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require curtailment of generation to resolve the problem.

The stochastic, sequential simulation methodology discussed in section 2.5.2 was used to evaluate the capability of the future system to meet the operational requirements with 20 percent renewable generation. The data and assumptions for the production simulation are discussed in Section 2.5.1. As summarized in Table 2.6, certain generation resources were assumed to be non-dispatchable in the production simulation. The generation profiles for these units, which included, Biomass, geothermal, QFs, hydro, and Imports, were based on either 2006 or 2007 actual operations as described in Section 2.5.1. It should be noted that the entire conventional gas fleet was assumed to be dispatchable in the production simulation. In other words, self-scheduling was not modeled in this analysis. The derivation of the generation profiles for variable energy resources and their day-ahead and hour-ahead forecasts is described in Section 2.5.2.1.

The simulations were targeted at selected days to examine the impact on load-following and regulation.[67] The procedure used for identifying interesting days for real-time simulations is described in Appendix C-1. This methodology identified a number of days in May 2012 with both high upward and downward load-following requirements as candidates for detailed real-time analysis. Table 5.1 shows the days selected for the sequential simulation, as well as the system conditions for each day. This section presents the results of the detailed analyses performed for two of the selected days (May 28, 2012 and May 17, 2012). The results for the remaining days are included as Appendix C.7.

Table 5.1: Characterization of System Conditions for the Days selected for Production Simulation

Date	Period	Load*	Non-Dispatchable Generation	Renewable Generation	Dispatchable Generation
May 28, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, low wind	Low
May 27, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, wind ramp down	Low
May 24, 2012	1 p.m.	High	High import, High hydro	Solar ramp down, wind ramp up	High
May 16, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High
May 17, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High

[67] It should be noted that the capability of the fleet to provide the regulation requirements determined in the operation analysis is studied using production simulation. However, this analysis does not attempt to identify the sufficiency of the regulation requirement since this would require sub-5-minute simulations that are beyond the scope of this analysis.

5.2.1 Load-following Capability under Low Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 28, 2012. The screening process showed the need for high load-following down requirement on this day. This day also had very limited dispatchable generation online during the low load periods in the morning. This was due to a number of reasons: high hydro and imports from neighboring regions and high wind generation in the morning. This day was also characterized by a rapid increase in solar generation between 5.00 a.m. and 8.00 a.m.[68] Figure 5-1 shows the load (black line) and non-dispatchable generation[69] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-1 is the amount of dispatchable generation available for load-following and regulation. Very few dispatchable resources are online during the morning hours, as is evident from the figure.

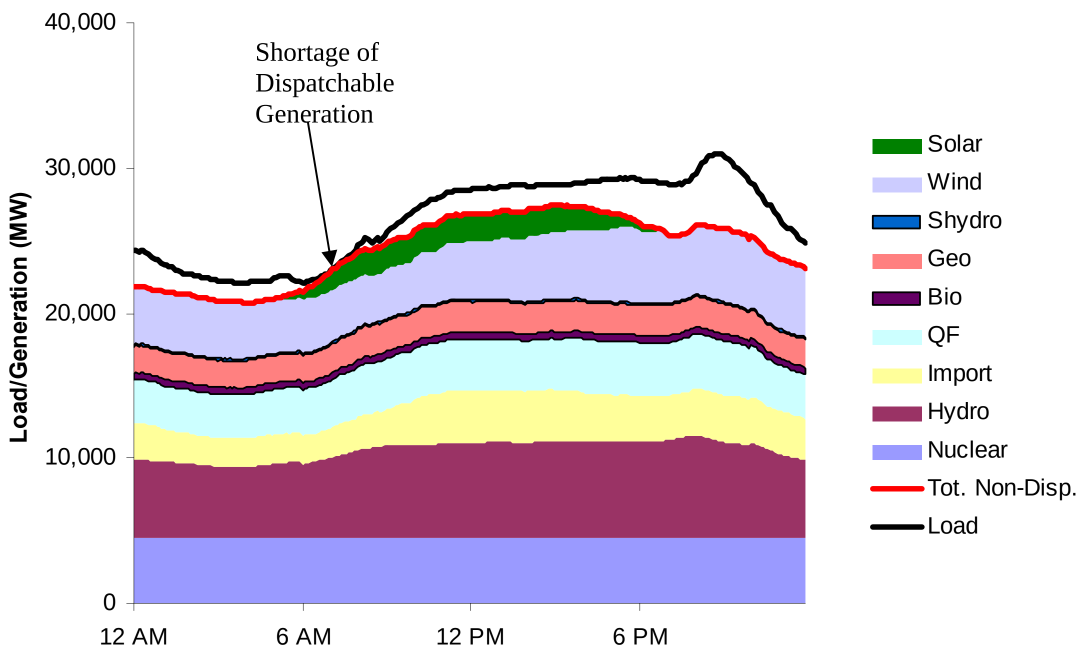

Figure 5-1: Load and Non-dispatchable Generation on May 28, 2010

Figure 5-2 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 28th, 2012. This is the capability of the dispatchable generators to move from one 5-minute dispatch to the next. The figure shows adequate 5-minute capability throughout the day and is comparable to the historical upward 5-

[68] Unlike wind generation, zero forecast error is assumed for solar generation both in the day-ahead and hour-ahead time frame in the production simulations. Errors due to solar forecast will exacerbate load-following shortages.

[69] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

minute capability show in Figure 4-1 of Section 4. However, the figure shows low load-following down capability during the morning hours from 4 a.m. to 10 a.m. It should be noted that Figure 5-2 shows the 5-minute capability for the day whereas the corresponding figures in Section 4 show the historical hourly maximum 5-minute load-following up and down capability. The low load-following down capability is a direct consequence of the amount of dispatchable generation that is online. During the morning hours of May 28th 2012, as shown in Figure 5-1, very few dispatchable generators are online and most are already operating at or close to their minimum load point.

As discussed in Section 3-3, insufficient capability to ramp down manifests itself as overgeneration in the production simulations. Figure 5-3 shows the overgeneration for May 28, 2012 obtained from the production simulation. This figure also shows the regulation down procurement (green line) and the CPS2 violation threshold[70] (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., the rest of the time the over generation can be covered by the procured regulation or allowed to result in an ACE error if it is not sustained. Only large overgeneration sustained over 10 minutes may result in the curtailment of generation.

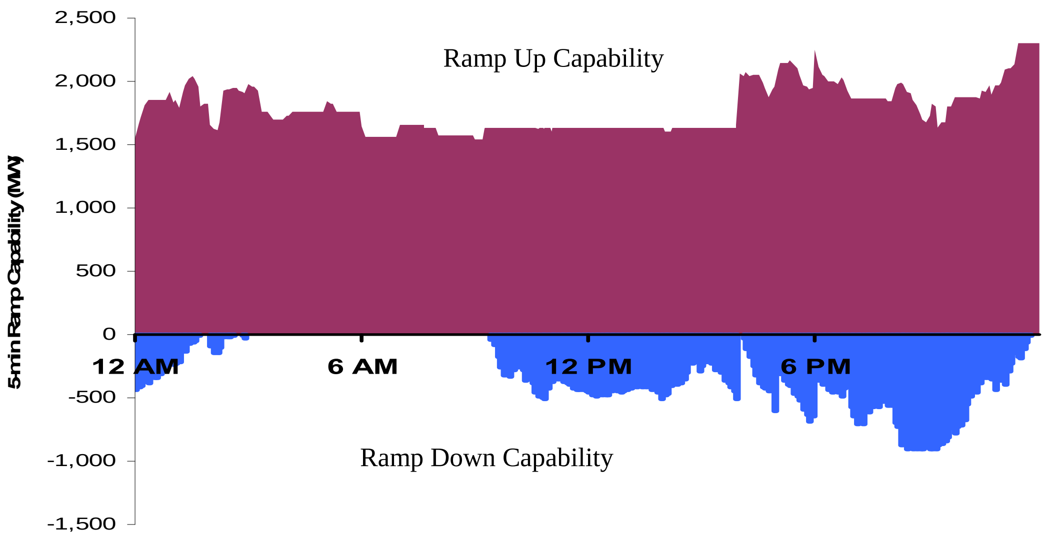

Figure 5-2: Upward and Downward 5-minute Load-Following capability for May 28th 2012

[70] CPS2 threshold is 110MW for ISO.

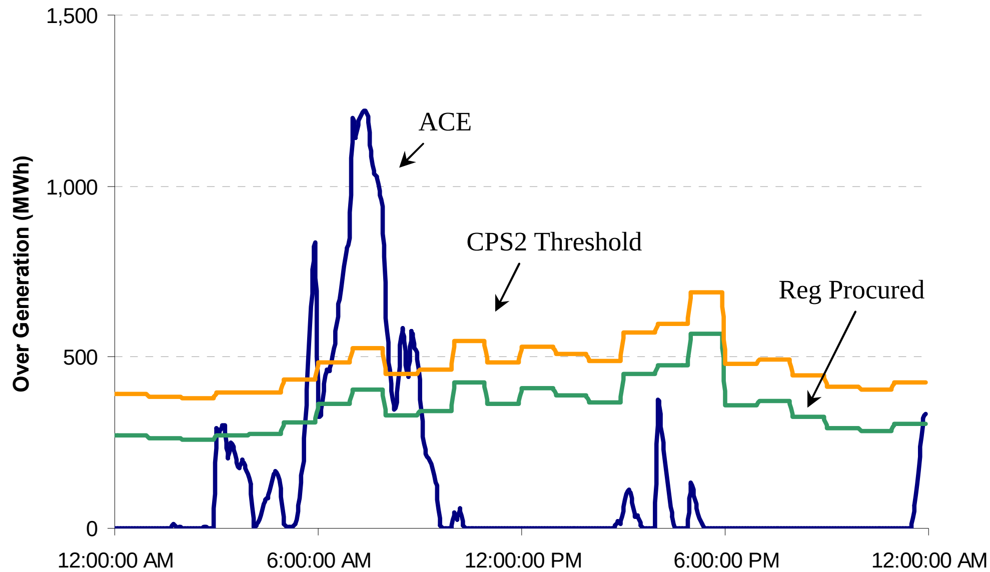

Figure 5-3: Detailed overgeneration analysis of May 28, 2012

Figure 5-4 shows the relationship between overgeneration and the amount of dispatchable generation during the hours between 4 a.m. and 10 a.m. The traces show that there is a direct correlation between overgeneration and lack of dispatchable generation. When the dispatchable generation is approaching zero, overgeneration is high. Under these conditions with very little dispatchable generation online, the fast ramp in solar generation results in an overgeneration condition. It should be noted that the solar generation ramp is not the cause of the overgeneration, rather it's the trigger. The cause for overgeneration is the lack of flexible or dispatchable resources during these hours.

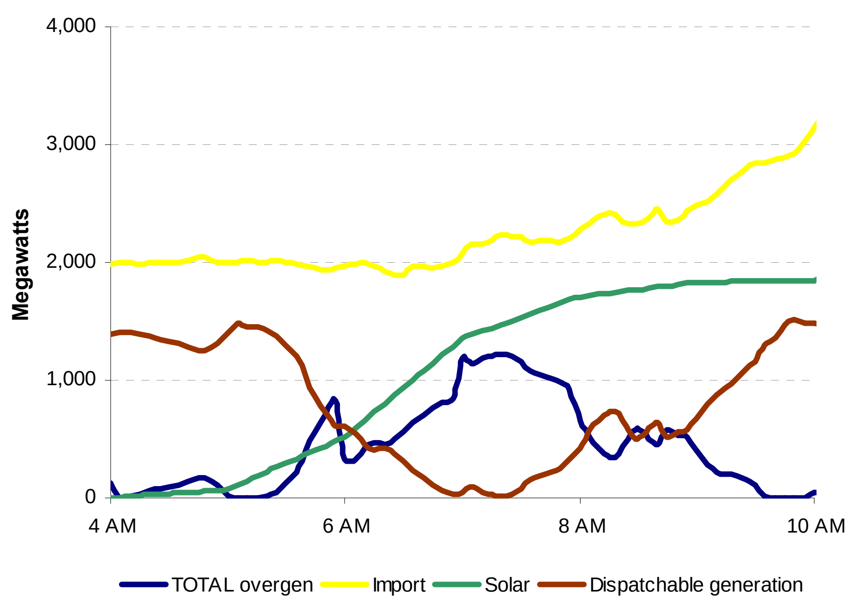

Figure 5-4: Dispatchable Generation and Overgeneration

5.2.2 Load-following Capability under High Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 17, 2012. The main difference in system conditions between May 28 and May 17 is the amount of non-dispatchable resources that were online due to lower imports. Figure 5-5 shows the load (black line) and non-dispatchable generation[71] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-5 is the amount of dispatchable generation available for load-following and regulation. More dispatchable resources are online during the morning hours, compared to May 28, 2012, as is evident from the figure.

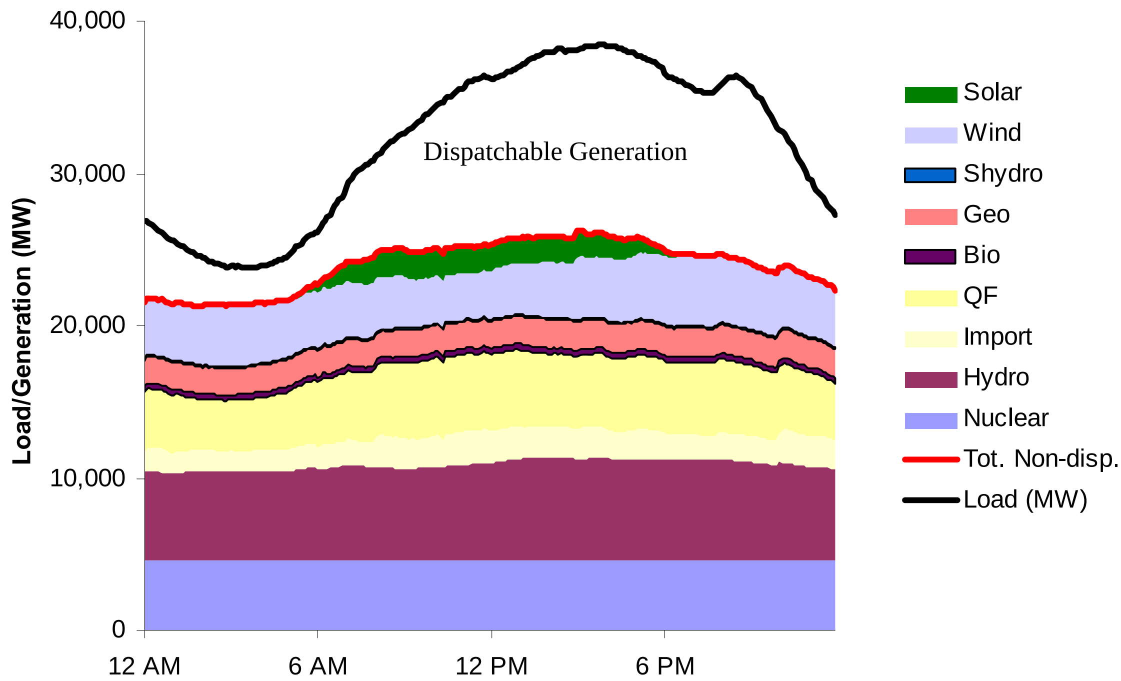

Figure 5-5: Load and Non-dispatchable Generation on May 17, 2010

Figure 5-6 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 17, 2012. The figure shows adequate capability throughout the day due to more dispatchable units being online.

[71] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

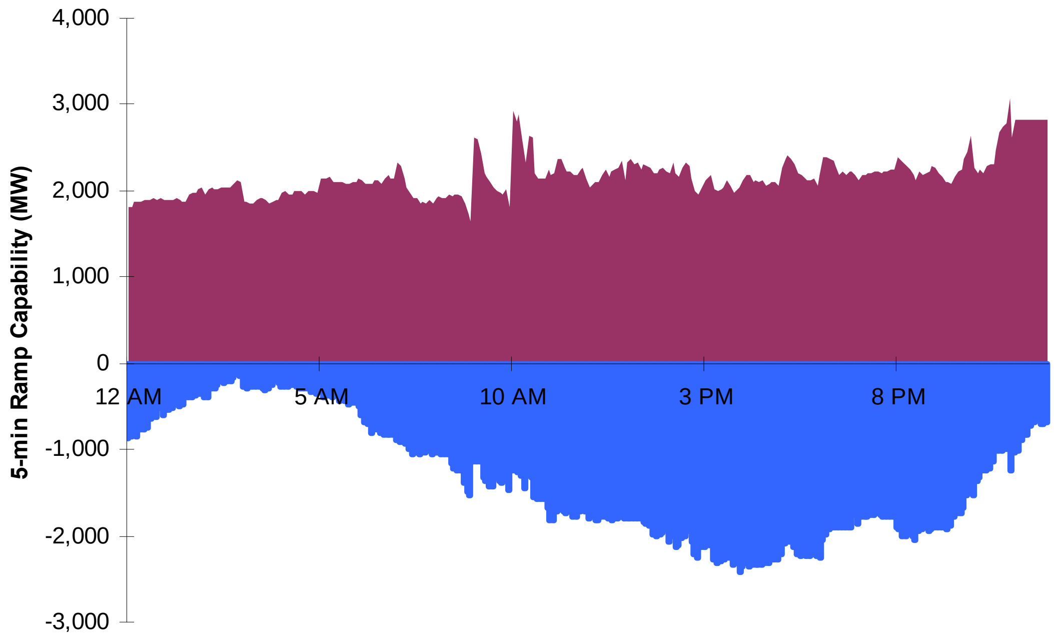

Figure 5-6: 5-minute ramp up and down capability for May 27, 2012

No overgeneration was observed in the 5-minute simulation of May 17, 2012. This reinforces the finding that load-following insufficiencies are primarily due to the lack of dispatchable generation resources. The results for the remaining days, summarized in Appendix C.7, also demonstrate that the lack of dispatchable resources causes the operational constraints. None of the detailed real-time simulations showed any significant upward load-following or regulation shortages indicating that the system has enough capability to meet load when there is a sudden decrease in variable energy resource generation.

To further analyze the impact of dispatchable gas-fired generation on overgeneration, a scatter plot of the two quantities was plotted. Figure 5-7 shows the plot of overgeneration (on the X axis) versus the amount of dispatchable gas-fired generation (on the Y axis) from a deterministic case[72] with all of the imports considered firm (100 percent firm import case). The deterministic cases that were simulated are discussed in Section 5.3. It can be observed that no overgeneration occurs when there is at least 1000 MW of dispatchable generation.

[72] In a deterministic simulation, uncertainty in load and wind generation is ignored, unlike a stochastic simulation. Since the run-time is lower, deterministic simulations were used to study the impact of various study assumptions on the results.

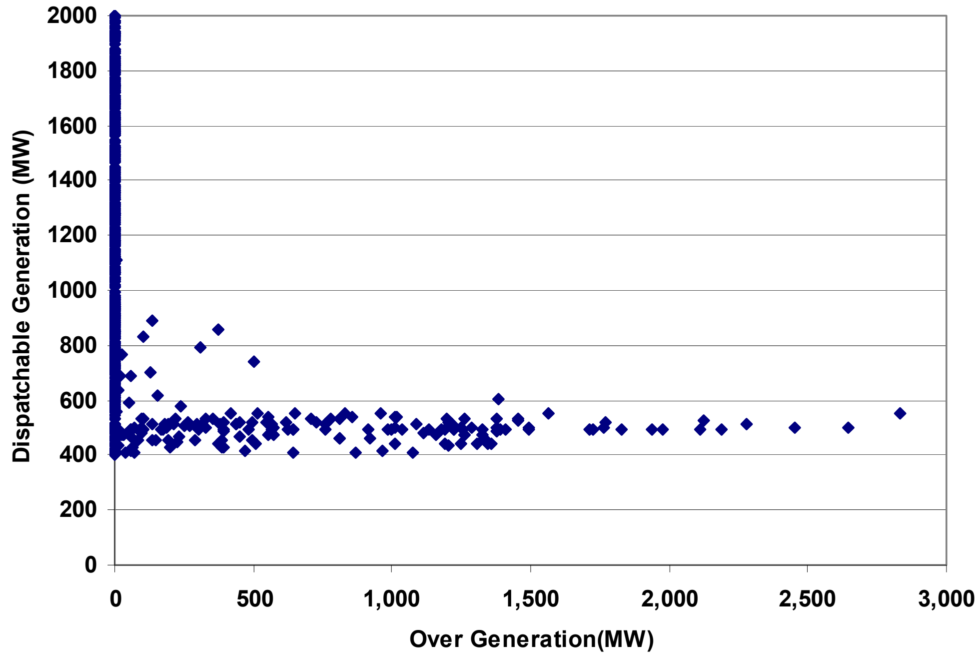

Figure 5-7: Overgeneration versus Dispatchable Generation

In contrast to the clear trend shown above, Figure 5-8 shows the overgeneration versus the system load. While no overgeneration occurs when the load is above 30,000 MW, the overgeneration occurs throughout the range of loads from 20,000 MW to 30,000 MW. These two figures again reinforce the finding that overgeneration is caused by shortages in downward dispatchable generation.

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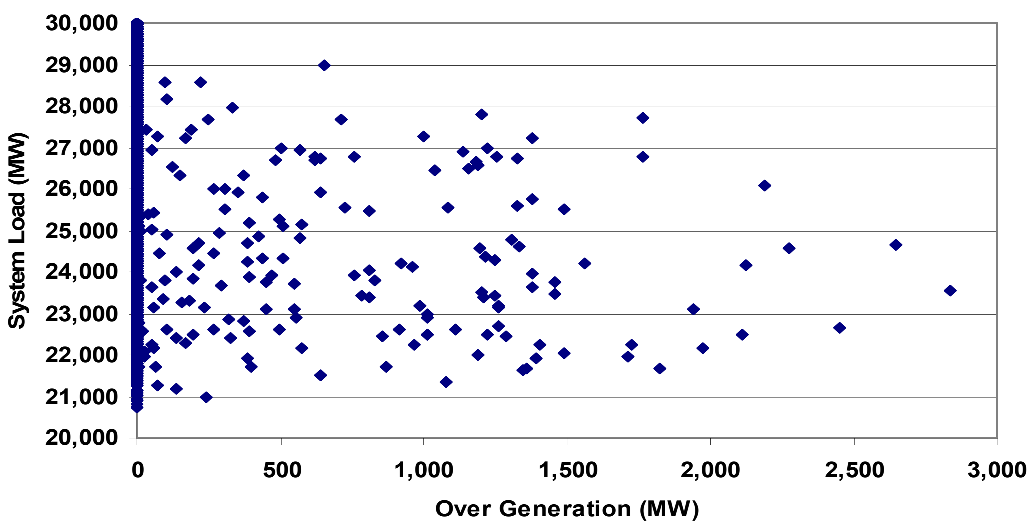


Figure 5-8: Overgeneration versus System Load

5.2.3 Quantification of Annual Load-following Shortages

The analysis shown in Section 5-2 is helpful in quantifying the shortages in load-following capability for a few selected days, and in understanding the factors that lead to the shortages. This section discusses the methodology that was used to estimate the shortage in load-following capability for the year.

Appendix C presents the results of the methodology that was used for identifying “interesting” days for stochastic, sequential simulations. The appendix discusses the approach for selecting the days for real-time simulation considering the impact of inflexibility in the existing fleet, and uncertainty and variability of load and variable energy resources on overgeneration. As shown by the hourly results in this appendix, most of the overgeneration is in the month of May, nearly 3.9 GWh. This month accounts for 80 percent of the annual overgeneration due to shortages of dispatchable generation, and uncertainty of load and generation from variable energy resources. Since this is an hourly simulation, it does not capture the impact of sub-hourly variability of load and generation from variable energy resources on the simulation.

Appendix C also quantifies the impact of intra-hour variability in load and generation from variable energy resources on overgeneration. The simulation of May 28, 2012 discussed in this appendix shows that variability increases overgeneration above and beyond what is caused by uncertainty alone. This is because variability imposes additional load-following constraints on the existing fleet, which might result in more overgeneration. Using May 28 as an example, variability doubles the overgeneration due to uncertainty of load and variable energy resources alone.

Table 5.2: Estimation of Annual Load-Following Shortages

Sensitivity Cases	GWh
(a) May overgeneration due to forecast uncertainty alone	3.90
(b) Estimated annual overgeneration due to uncertainty alone [1.20*(a)]	4.68
(c) Estimated annual overgeneration due to uncertainty and variability [2.2*(b)]	10.30

Using the information from the real-time hourly stochastic simulations, the regulation and load-following shortages for the year were estimated. Cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012 as shown in Table 5.2. This is roughly 0.06 percent of the wind generation and 0.02 percent of the total renewable generation in 2012.

5.3 *Impact of Non-dispatchability on Overgeneration*

As mentioned previously, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. It was shown in Section 5.2 that shortages in dispatchable generation cause an inability to follow load, which in turn causes overgeneration. The preceding section quantified overgeneration due to the variability and uncertainty associated with load and variable energy resources to be 10 GWh for the year 2012. It should be pointed out that the overgeneration in this case is due to the inability of the fleet to follow net load changes in the sub-hourly time frame.

Even if the generation from wind and solar resources could be perfectly forecasted and were constant (i.e., no uncertainty and variability), the maximum generation that can be accommodated into the system will depend on the ability to dispatch the existing fleet. In this case, the overgeneration has nothing to do with the variability and uncertainty of variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

The impact of dispatchability on overgeneration was studied both under high and low hydro conditions, under a range of assumptions regarding the dispatchable capability of generation resources and imports. This sensitivity analysis used a deterministic production simulation on an hourly basis. The intra-hourly variability and the forecast uncertainty associated with generation from variable energy resources were not modeled (but they were rather modeled as fixed, but variable by hour, production profiles). Certain portions of the generation fleet such as QFs, nuclear, biomass, hydro and imports were assumed to be non-dispatchable in this analysis. Historical hourly dispatches were assumed for these resources.

However, in reality, not all of these resources are always non-dispatchable. For example, based on an analysis of the bid data, 50 percent of the imports into California in 2006 were found to be bid into the market on an hourly basis, with the remaining being scheduled hourly as firm. The impact of increasing the dispatchable capacity on the system on the frequency and magnitude of overgeneration was studied by assuming various levels of firm imports (50 percent, 75 percent and 100 percent). Since overgeneration is more likely to occur at low loads, the impact of zero load growth from 2006 to 2012, but with the expected renewable generation additions, was also studied. A deterministic production simulation on an hourly time-step was conducted for all these cases. The assumptions for the deterministic cases are shown in Table 5.3.

Table 5.3: Assumptions for the Deterministic Production Simulations

Case	Load	Imports
50 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
75 % Import Case	2006 Load ×(1+0.015)^6	100% Fixed
100 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
No Load Growth Case	2006 Load	50% Fixed*, 50% Dispatchable

* Based on 2006 imports

Under the assumptions listed above, in the base case simulation, with 50 percent firm imports, no overgeneration was observed as a result of shortages in dispatchable generation. The most severe overgeneration was from the zero load growth case, as shown in Figure 5-9. Overgeneration in this case was roughly 150 GWh for the year, which is 0.84 percent of the expected wind energy and 0.32 percent of the total renewable generation in 2012. Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. The 75 percent and 100 percent import cases also showed some overgeneration as shown in Figure 5-9. In general, there appears to be sufficient flexible generation available to operate, if the ISO is not blocked from doing so due to an excess of non-dispatchable generation, including imports.

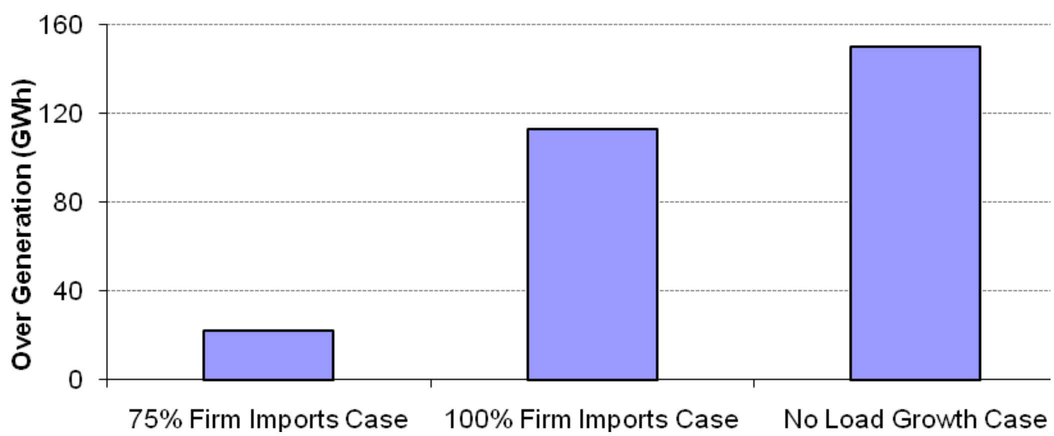


Figure 5-9: Volume of Annual Overgeneration (GWh) in Three Sensitivity Cases

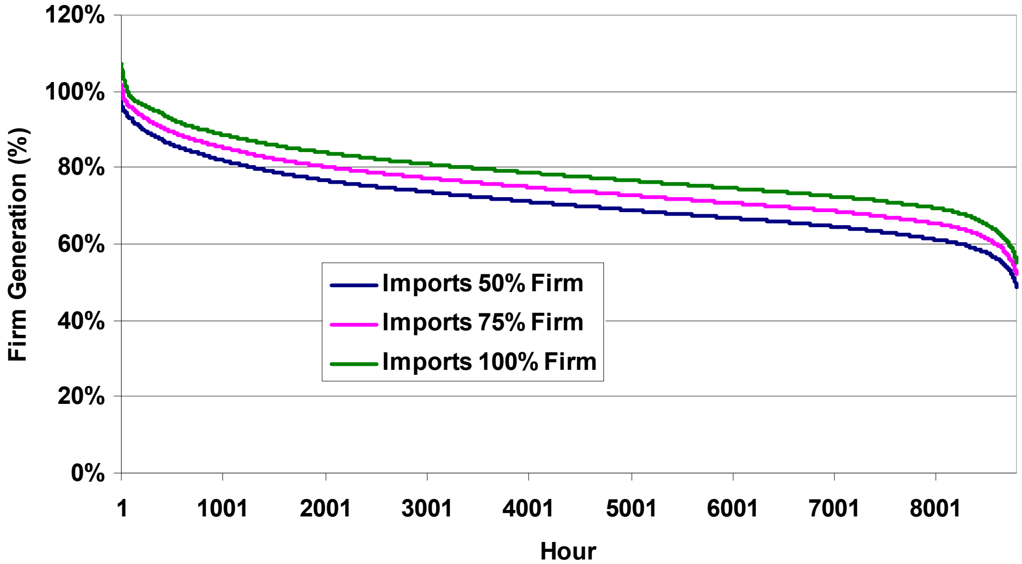


Figure 5-10: Duration curves for non-dispatchable generation with different levels of firm imports

Figure 5-10 shows the non-dispatchable generation in the three cases (50 percent, 75 percent and 100 percent import) as a percentage of the load. It can be observed that at higher percentages of firm imports, the total non-dispatchable generation is higher than load during a few hours, which results in overgeneration.

5.4 Fleet Operations and Economic Impacts

The production simulations results were also used to provide an initial evaluation of the impacts of 20 percent renewable energy production on the operations and revenues of the dispatchable thermal generation fleet. Table 5.4 shows the impact on the combined cycle fleet. This table shows the number of starts, on-peak and off-peak energy, CO2 emissions and revenues for the 20 percent RPS case, as well as the 2012 Reference case.[73] Tables 5.5 and 5.6 show the impacts on the simple cycle gas turbine and gas-fired steam turbine fleet, respectively. The 20 percent renewable energy modeled results in the combined cycle units starting and stopping more frequently. With the additional renewable production, combined cycle generator starts increase by 35 percent. Also, the energy from the combined cycle units reduces by roughly 9 percent, with more reduction occurring during off-peak hours, indicating increased cycling. The table also shows a reduction in CO_2 emissions from combined cycle generators due to the reduction in operations, although this was calculated using a single emissions factor multiplied by energy output, and did not consider the potential for higher emissions at less efficient levels of operations.

[73] The 2012 Reference case uses the same load and other assumptions as the 20 percent RPS case, except that the renewable portfolio includes only the renewable resources online in 2006.

Table 5.4: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table 5.5: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

Table 5.6: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

While the number of starts for combined cycle units increase with 20 percent renewable energy, the simulations show that the number of starts, along with energy produced, decrease quite substantially for simple cycle gas turbines and gas-fired steam turbines.

Figures 5-11 and 5-12 show the generation from combined cycle, simple cycle and gas-fired steam turbines for the same week in January, 2012, for the two cases. The combined cycle energy (area shown in blue) is smaller for the 20 percent RPS compared to the 2012 reference case. Also, the valleys in combined cycle generation are deeper indicating that more of these units either turn down and shutdown during off-peak hours.

Two conflicting impacts are at work here. On the one hand, the renewables decrease the overall amount of gas-fired generation required. The overall level of gas generation drops several thousand MW across the week, thereby decreasing the total energy and the number of starts. The average displacement by season and hour due to the renewable profiles being modeled can be seen in the gap between the load and net load in Figures 2-1 to 2-4. On the other hand, the uncertainty and variability tends to push up the number of starts. These simulation results likely underestimate production because intra-hourly load-following is not modeled.

Figures 5-13 and 5-14 show the seasonal on-peak and off-peak energy from combined cycle, simple cycle GT, gas-fired steam, wind and solar resources for the 20% RPS case and the 2012 reference case. From these two figures, it is clear that during on-peak hours, the incremental wind and solar generation displace the generation primarily from simple cycle and gas-fired steam generators. During off-peak hours, the generation from the incremental wind and solar generation has a bigger impact on the generation from combined cycle units.

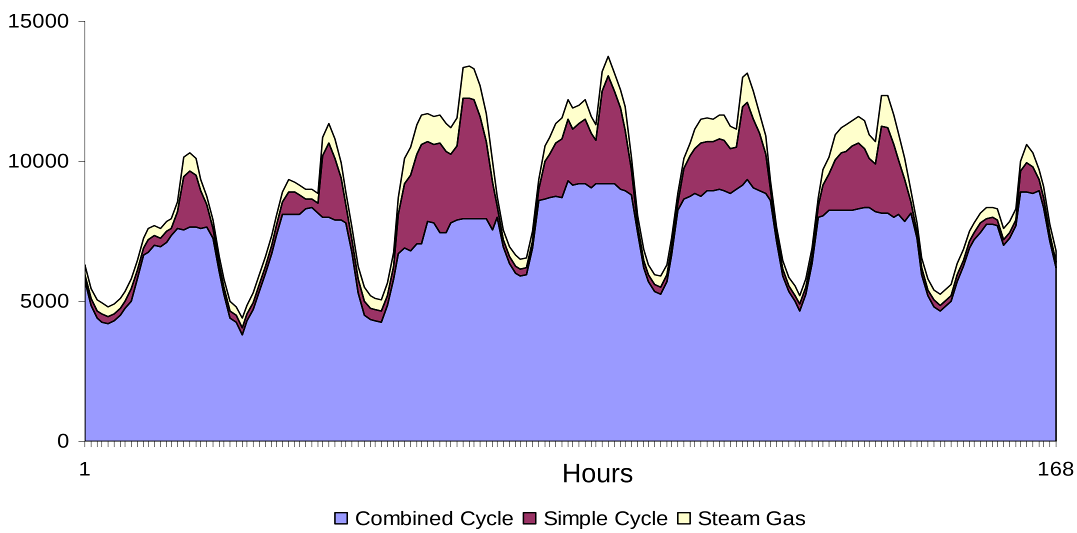


Figure 5-11: Weekly generation for gas units in the 2012 reference case

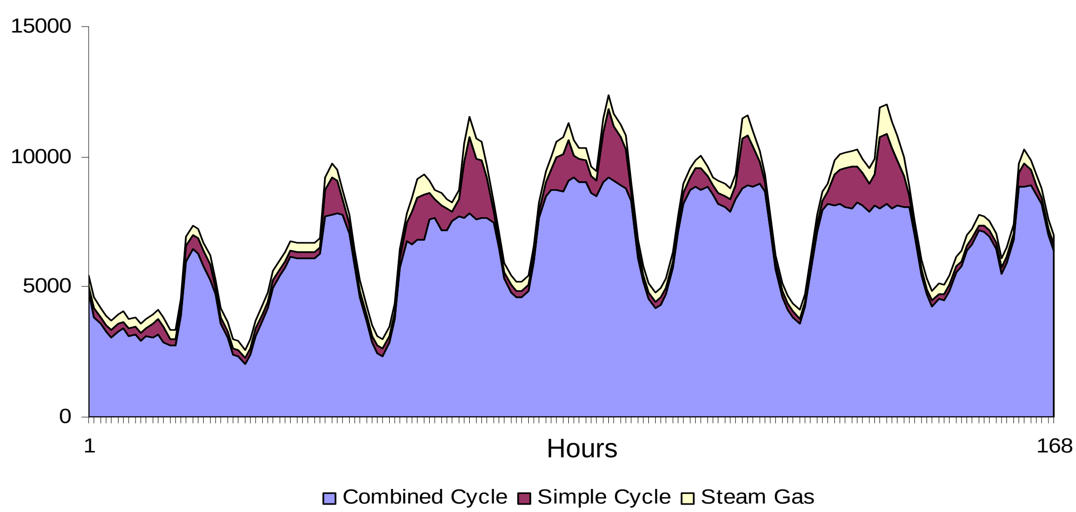


Figure 5-12: Weekly generation for gas units in the 20 percent RPS case

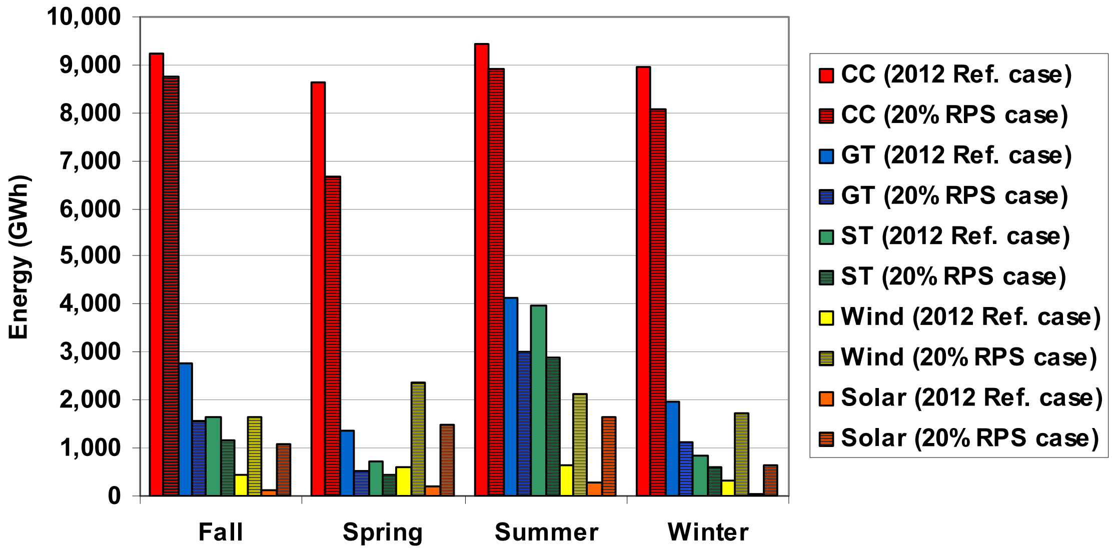


Figure 5-13: Seasonal on-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

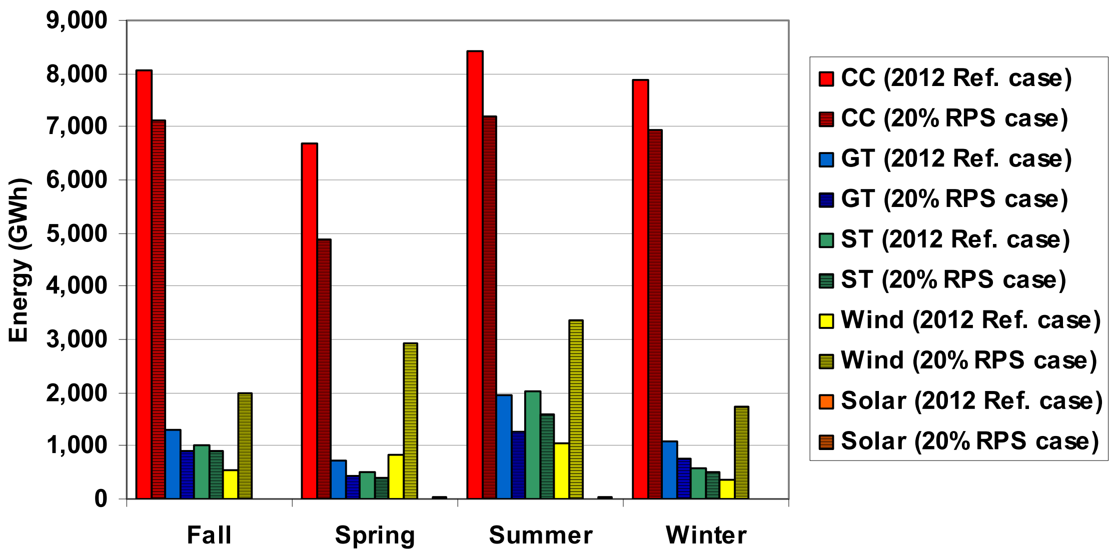


Figure 5-14: Seasonal off-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

The energy market revenues for the combined cycle, simple cycle gas turbine and steam units are lower in the 20 percent RPS case, compared to the 2012 reference case, by 16 percent, 39 percent and 29 percent respectively. The revenues for combined cycle, simple cycle gas turbine and steam units are lower due to the compounding effect of lower dispatch and lower energy prices. Figure 5-15 and 5-16 show the energy prices in the summer and spring for the two cases. The figure shows the minimum, maximum and standard deviation of the seasonal average hourly spot prices. On an average, the energy prices in the 20 percent RPS case are lower by $2.50 /MWh compared to the 2012 reference case. The lower energy prices, combined with the lower capacity factor, have a negative impact on the revenues of thermal units. Peaking units such as simple cycle gas turbines and steam turbines are impacted more in the 20 percent RPS case because they operate less during the peak hours of the days when energy prices are higher.

Also, it can be observed that the price volatility is higher in the 20 percent RPS case. The spring plot shows few hours when the price is zero or negative due to overgeneration. These periods correspond to solar and wind ramp up periods discussed in other sections of the report. The price volatility in the negative direction also has an impact on generator revenues.

These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues. Further analysis to quantify operational and economic impacts on fleet is required, especially at higher levels of RPS.

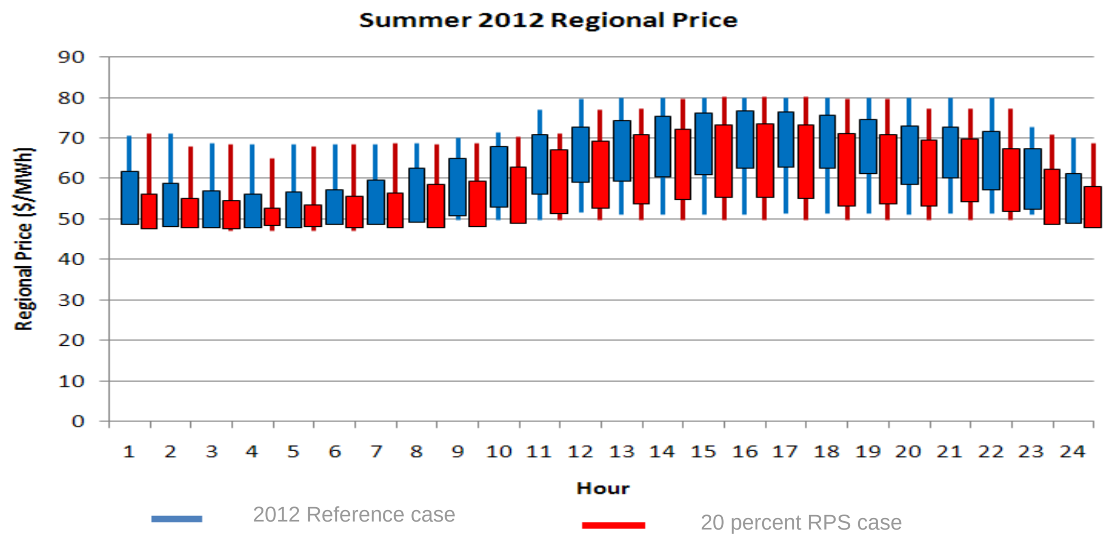


Figure 5-15: Summer 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

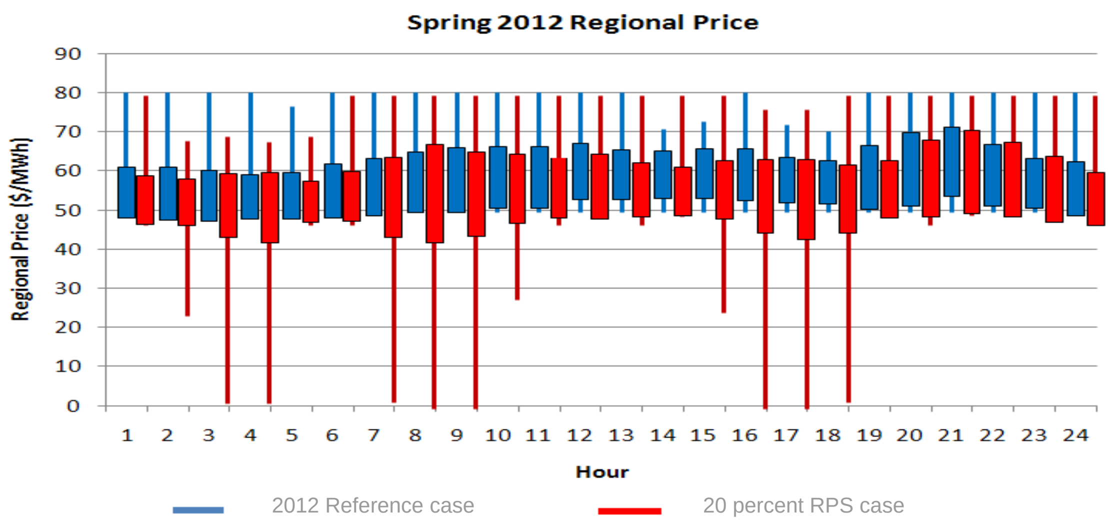


Figure 5-16: Spring 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

6 Key Study Conclusions and Recommendations

The study shows that the generation fleet is capable of meeting the regulation up and down requirements, as well as the load-following ramp up requirements under the 20 percent RPS. Sufficient upward ramp capability was found both in the empirical analysis of the dispatch over the past 15 months (although there may be few intervals in the analysis where upwards capability is tight) and the production simulations.

The production simulation analysis showed that under certain conditions (for example, low load, high hydro and wind generation in May), the system may not have adequate flexible generation to meet the load-following down ramp requirement. In the methodology that was employed, the shortages in the ramp down capability are captured as overgeneration. The cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012. This is roughly 0.02 percent of the expected renewable generation in 2012 and fairly insignificant. However, in the production simulations, the entire gas fleet was assumed to be dispatchable. The ramp down shortages can be exacerbated due to self-scheduling. Hence, the simulation result may be an under-estimate of actual overgeneration at 20 percent RPS.

Currently, a large portion of the generation fleet is self-scheduled and therefore not responding to 5-minute economic dispatch commands from the ISO. As a result, some periods may have insufficient dispatchable generation to follow load and variable energy production. The fleet capability analysis shows that due to self-schedules, the downward 5 minute capability of the generation fleet can be depleted. However, if no resource self-schedules, there is sufficient downward ramp capability inherent in the dispatch. This finding points to the significant negative impact that self-scheduling could have on efficient commitment and dispatch in high renewables scenarios. In fact, the ISO is already experiencing many hours of negative prices during off-peak hours in spring and summer, which is an indication that self-schedules are being violated to ensure reliable operations.

The study results indicate that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources during certain periods. The reduction in self-schedules will give the system the needed down ramp capability under certain conditions. The same outcome can also be achieved by reducing the amount of other non-dispatchable generation that are in the form of imports, hydro, QFs, geothermal etc. during these periods. There appears to be sufficient flexible generation available to operate with a 20 percent RPS if the ISO is not blocked from doing so due to an excess of non-dispatchable generation (including imports).The ISO is undertaking a large number of initiatives in system operations (notably improved wind and solar forecasting and visualization capabilities), grid planning and market design to prepare for renewable integration. These initiatives will not be reviewed here, but rather a few key recommendations that reflect the study findings are summarized.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility**. As noted, the study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets restrict ISO's access to that full capability due to self-scheduling. The empirical analysis provided information on the difference between load-following capabilities in the downward direction when resources are self-scheduled compared to their actual physical capabilities. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch or ancillary services. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfall in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: *(a) develop a regulation prediction tool.*** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a means to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance the efficiency of regulation procurement in the day-ahead time frame.

- **Improve day-ahead and real-time forecasting of operational needs: *(b) develop a ramp/load-following requirement prediction tool.*** The study identified the potential for significant increases in load following capacity and ramp requirements at 20 percent RPS. While forecasts can identify the need in the day-ahead and hour-ahead time frame, they cannot currently identify the presence of ramp constraints that may limit the ability of generation to meet those requirements. The ISO should evaluate the development of improved forecasting of ramp requirements and whether to modify day-ahead and real-time unit commitment algorithms and processes to reflect those ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact over time from changes in energy and ancillary services procurement, as well as consideration of the implications for capacity payments.

APPENDIX A-1: Comparison of seasonal results for the operational requirements simulations

This appendix presents supplemental figures and tables for Section 3, showing all seasons. Definitions of the operational requirements shown in the figures and tables are the same as in Sections 2 and 3, as is discussion of the methodology used for the simulations

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In the figures, the hourly results are represented as typical “stock” or “whisker” charts. The two ends of the line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars and lines refer to the 2012 simulations; Blue bars and lines refer to the 2006 simulations.

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[1]

[1] That is, excluding the 5% highest results from the simulations.

Figure A-1: Regulation Up Capacity Requirements by Hour of Day, All Seasons

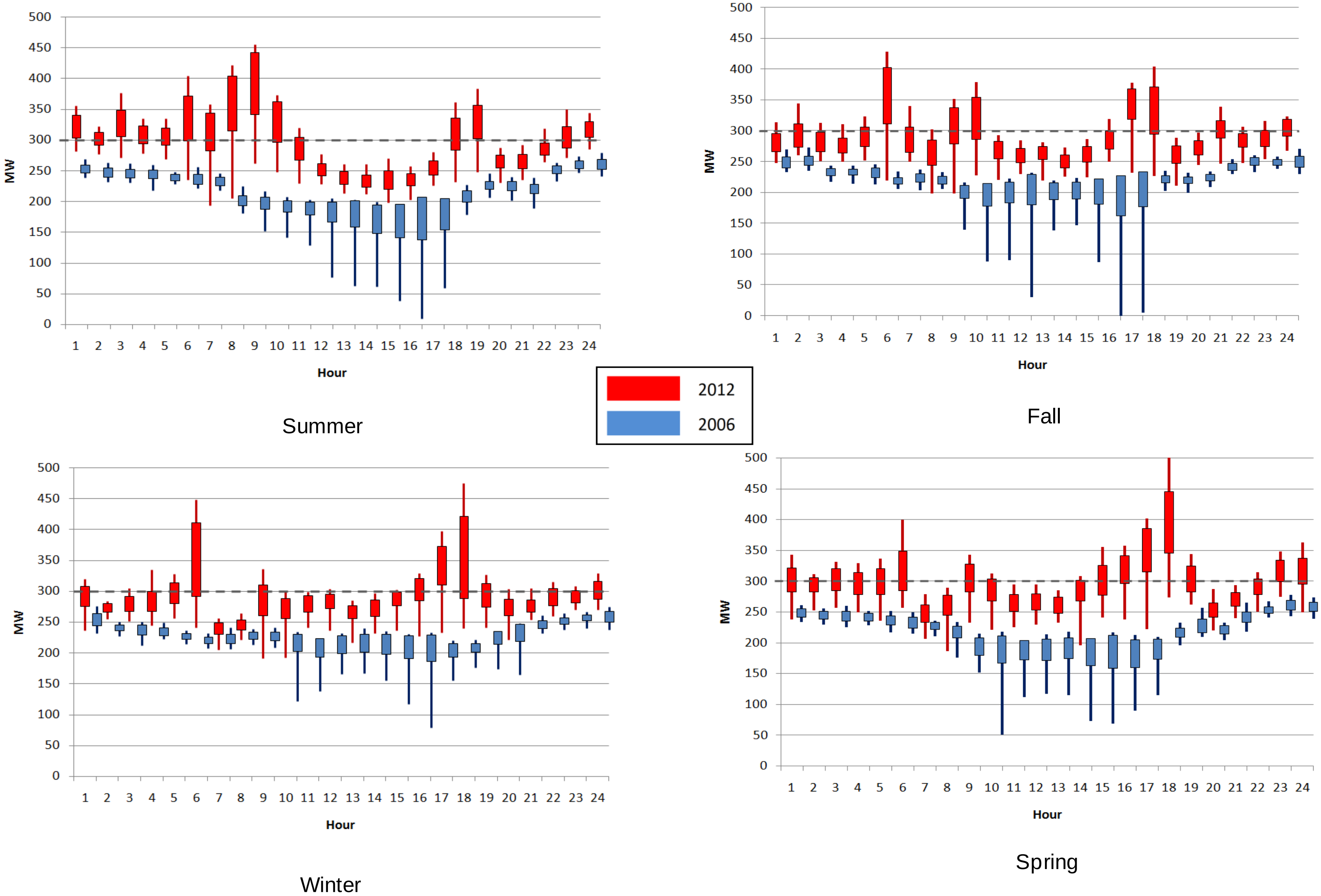


Figure A-2: Regulation Down Capacity Requirements by Hour of Day, All Seasons

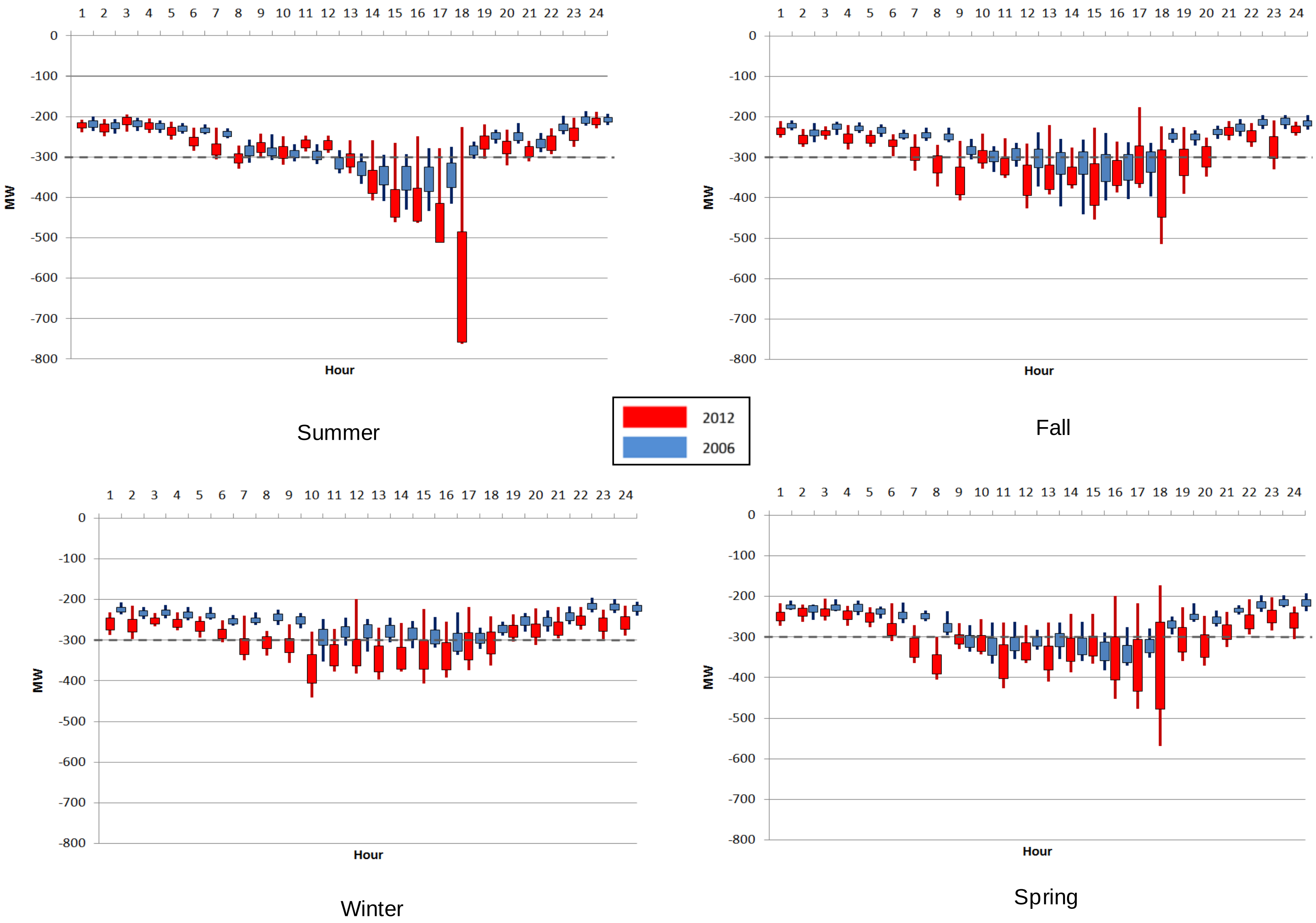


Figure A-3: Load Following Up Capacity Requirements by Hour of Day, All Seasons

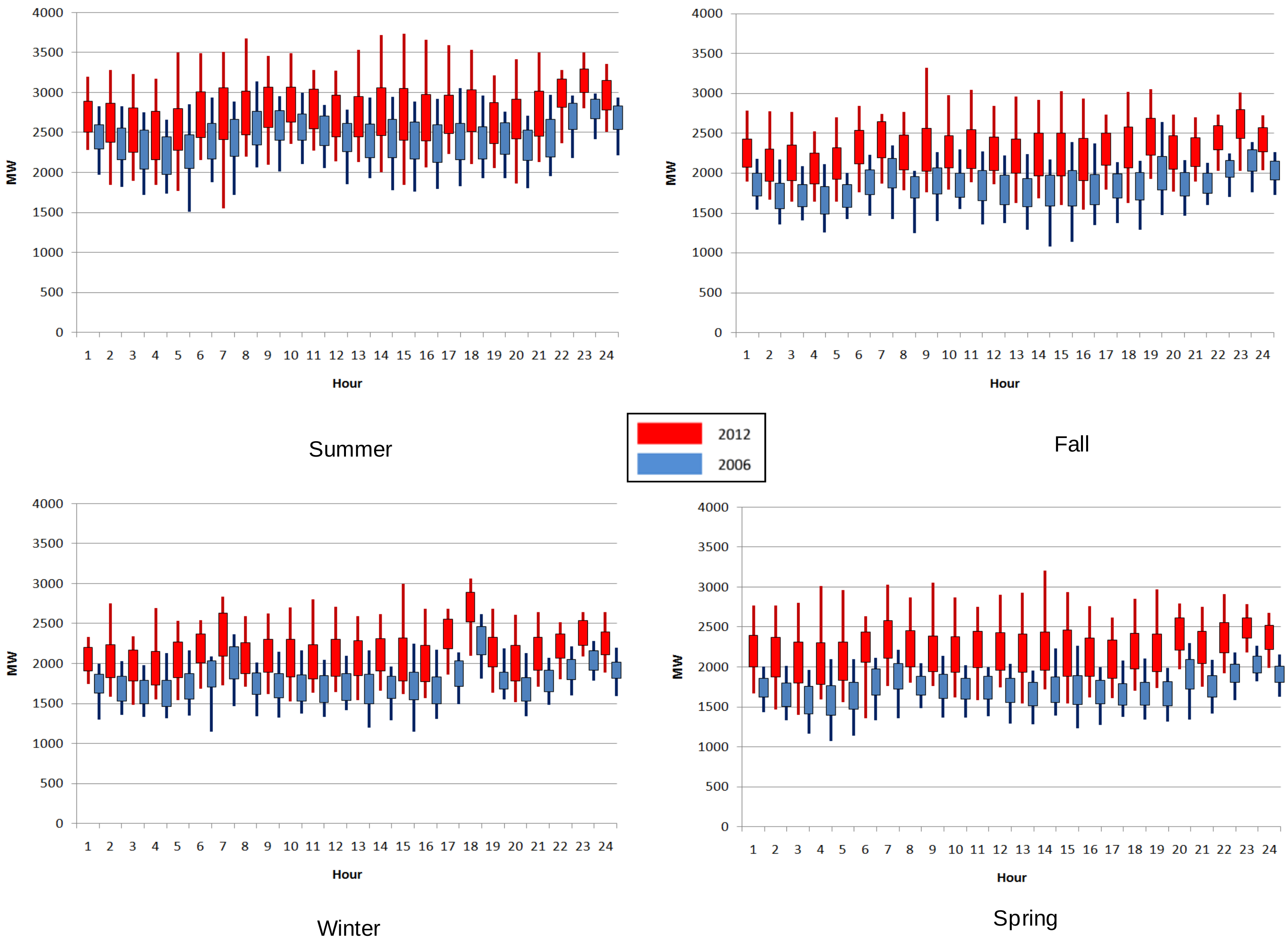


Figure A-4: Load Following Down Hourly Capacity Requirements by Hour of Day, All Seasons

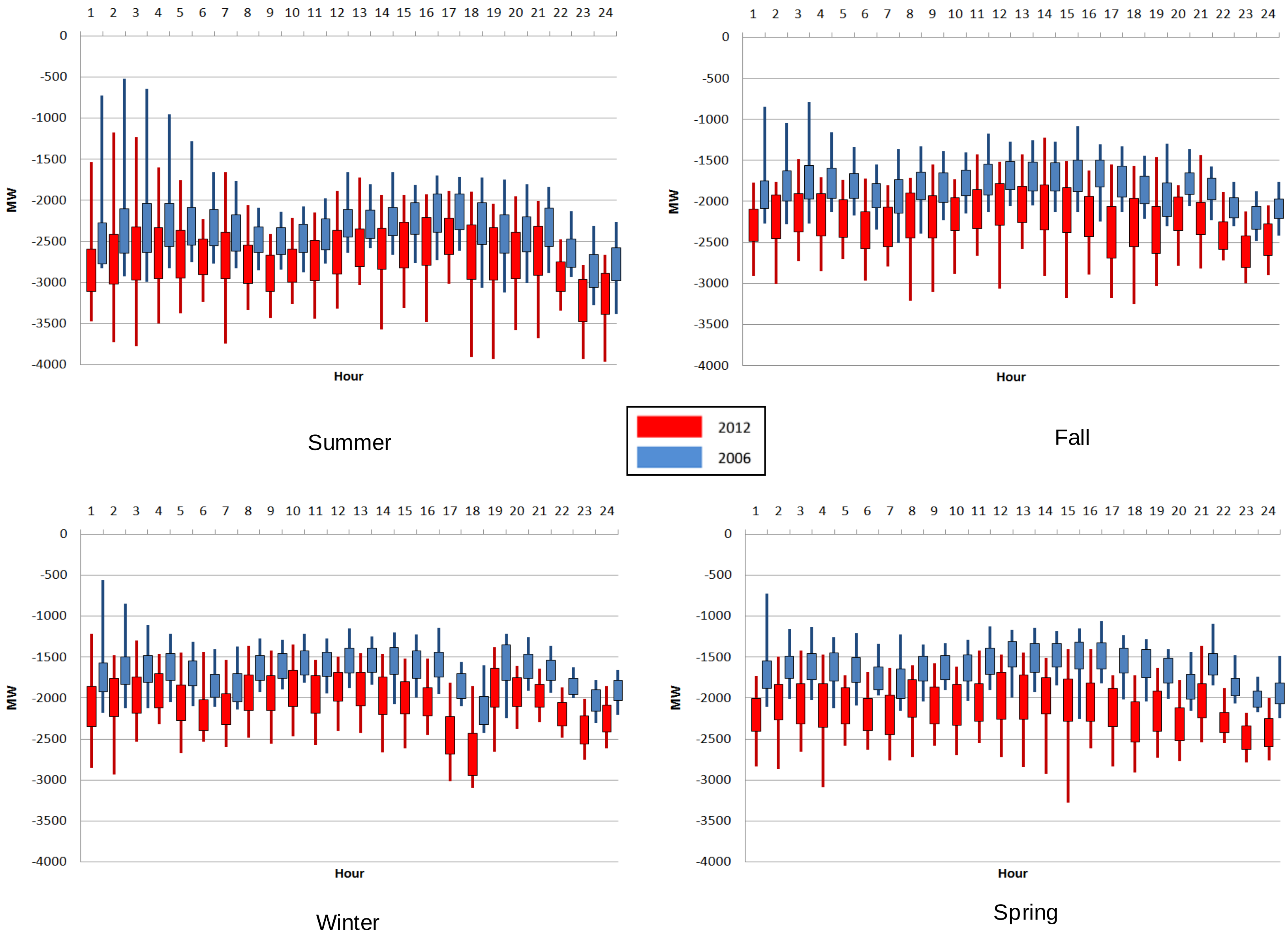


Figure A-5: Regulation Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

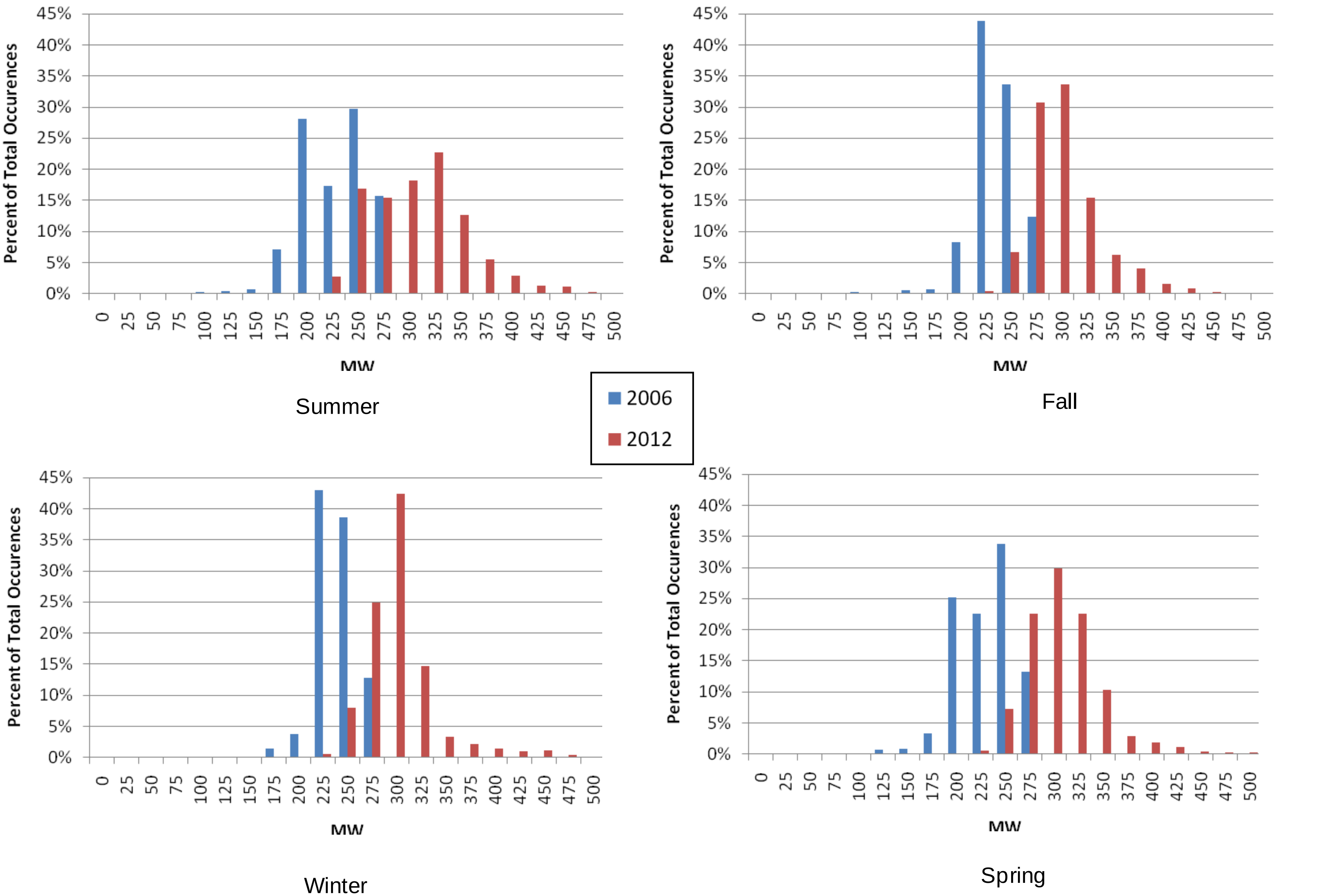


Figure A-6: Regulation Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

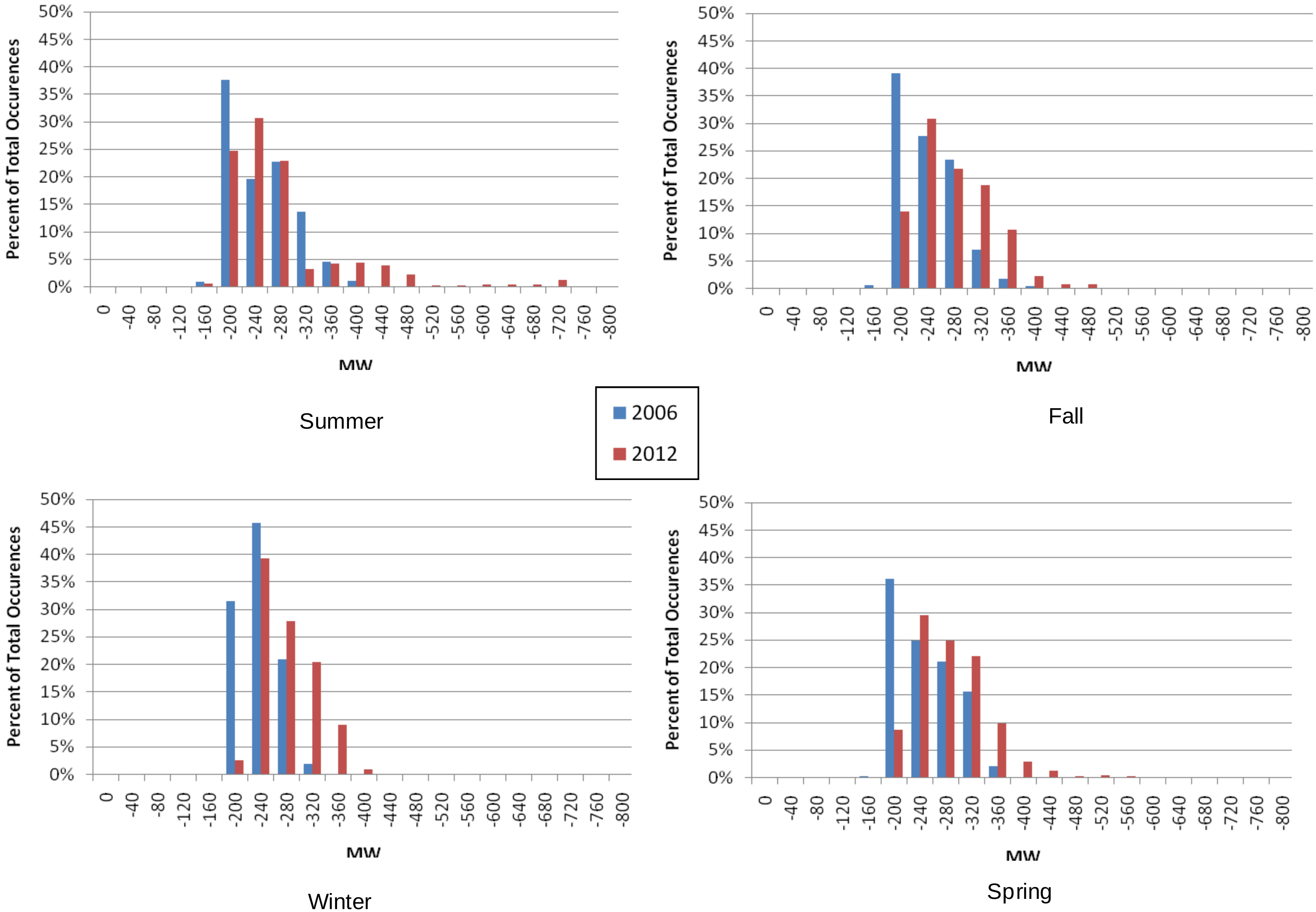


Figure A-7: Load Following Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

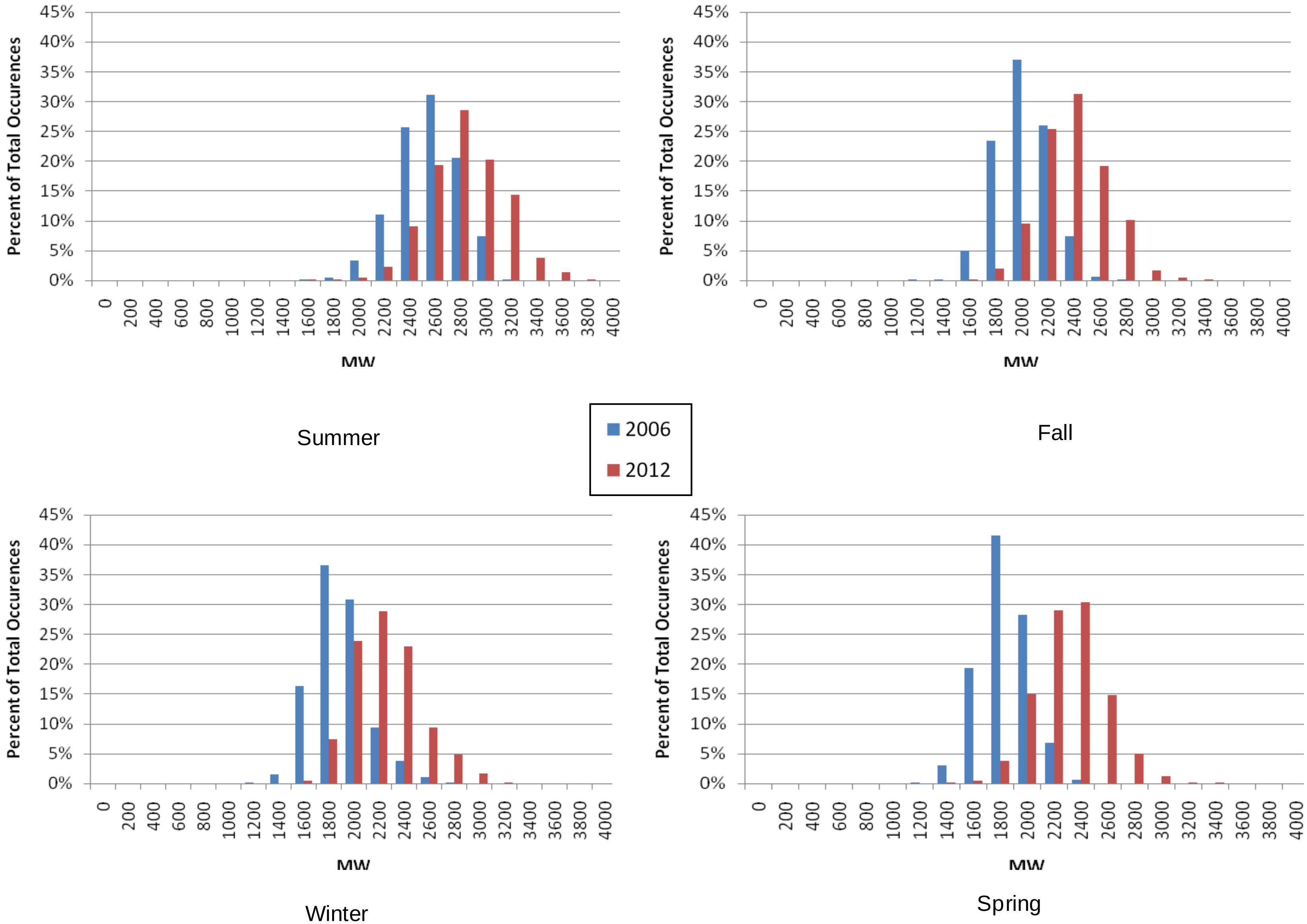


Figure A-8: Load Following Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

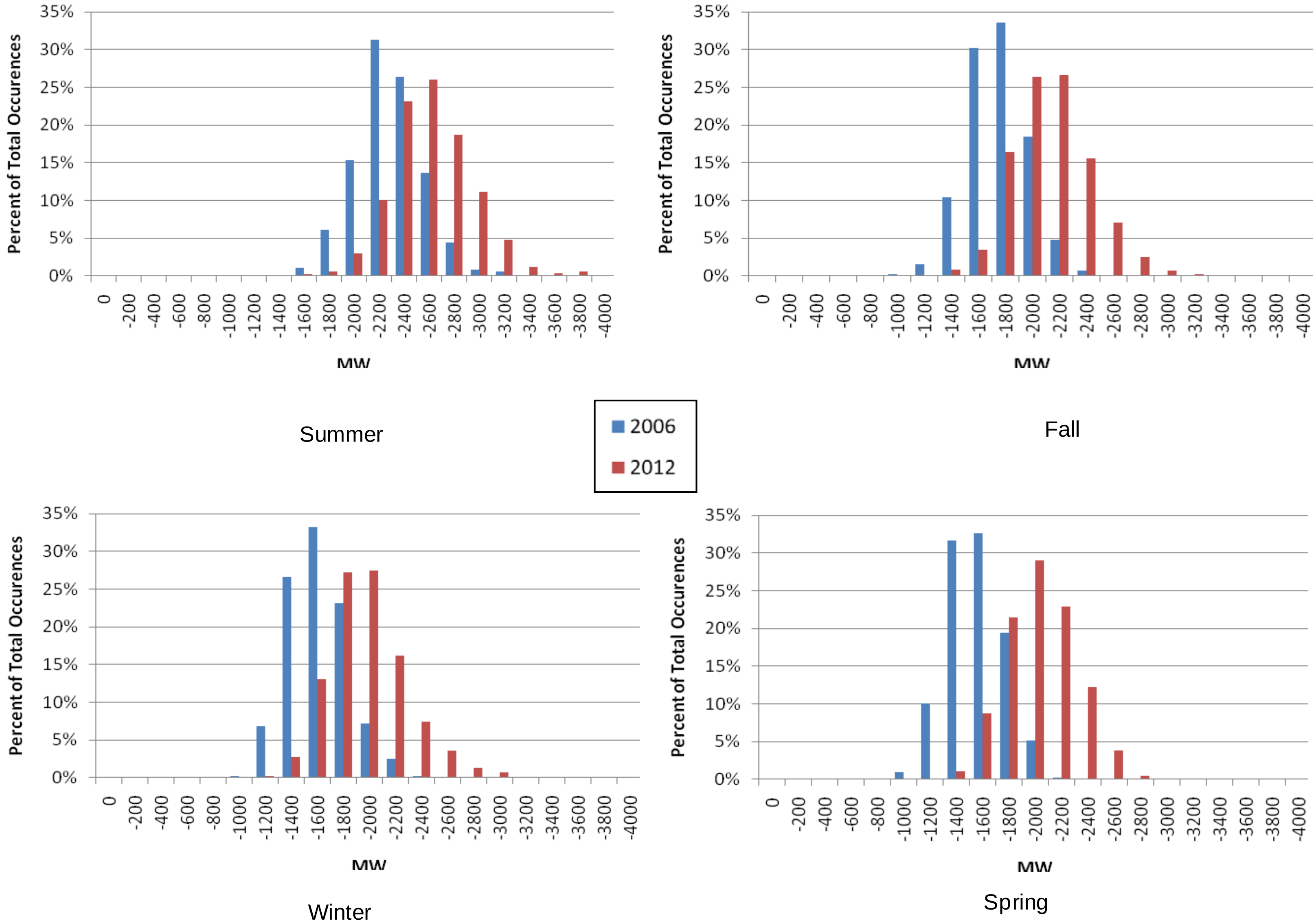


Table A-1: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,767	2,773	2,801	3,012	2,968	2,639	3,030	2,871	3,055	2,873	2,755	2,901
Maximum load-following up capacity (MW) – 2006	1,999	2,008	1,963	2,091	2,093	2,109	2,207	2,046	2,132	2,013	1,991	2,036
Maximum load-following down capacity (MW) – 2012	(2,836)	(2,868)	(2,654)	(3,088)	(2,580)	(2,630)	(2,765)	(2,723)	(2,581)	(2,698)	(2,548)	(2,722)
Maximum load-following down capacity (MW) – 2006	(2,100)	(1,999)	(2,019)	(2,117)	(2,082)	(1,958)	(2,145)	(2,038)	(1,893)	(2,029)	(1,895)	(1,988)
Maximum Regulation Up capacity (MW) – 2012	343	311	331	329	336	399	279	289	342	312	294	294
Maximum Regulation Up capacity (MW) – 2006	260	255	259	251	251	249	234	233	214	217	202	213
Maximum Regulation Down capacity (MW) – 2012	(273)	(263)	(259)	(273)	(277)	(311)	(364)	(406)	(330)	(343)	(426)	(365)
Maximum Regulation Down capacity (MW) – 2006	(233)	(258)	(236)	(245)	(255)	(265)	(261)	(295)	(336)	(366)	(354)	(331)

Table A-2: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,928	3,207	2,942	2,762	2,621	2,857	2,976	2,794	2,752	2,918	2,788	2,678
Maximum load-following up capacity (MW) – 2006	1,953	2,228	2,259	1,991	2,079	2,102	1,987	2,292	2,088	2,175	2,260	2,148
Maximum load-following down capacity (MW) – 2012	(2,845)	(2,926)	(3,275)	(2,614)	(2,838)	(2,910)	(2,731)	(2,771)	(2,542)	(2,548)	(2,782)	(2,761)
Maximum load-following down capacity (MW) – 2006	(1,922)	(1,840)	(2,246)	(1,816)	(2,012)	(2,030)	(2,004)	(2,148)	(1,834)	(2,061)	(2,166)	(2,239)
Maximum Regulation Up capacity (MW) – 2012	286	309	356	358	402	502	344	287	293	315	348	363
Maximum Regulation Up capacity (MW) – 2006	217	205	215	212	209	232	255	232	264	266	277	272
Maximum Regulation Down capacity (MW) – 2012	(410)	(387)	(366)	(452)	(476)	(569)	(359)	(371)	(325)	(294)	(284)	(305)
Maximum Regulation Down capacity (MW) – 2006	(353)	(359)	(382)	(371)	(350)	(293)	(263)	(273)	(245)	(237)	(226)	(236)

Table A-3: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	3,198	3,285	3,234	3,174	3,500	3,496	3,507	3,675	3,461	3,491	3,281	3,278
Maximum load-following up capacity (MW) – 2006	2,826	2,823	2,752	2,663	2,854	2,933	2,888	3,140	2,948	2,993	2,845	2,782
Maximum load-following down capacity (MW) – 2012	(3,473)	(3,727)	(3,774)	(3,496)	(3,372)	(3,238)	(3,745)	(3,333)	(3,432)	(3,258)	(3,438)	(3,316)
Maximum load-following down capacity (MW) – 2006	(2,810)	(2,911)	(2,972)	(2,809)	(2,743)	(2,752)	(2,814)	(2,838)	(2,830)	(2,862)	(2,754)	(2,624)
Maximum Regulation Up capacity (MW) – 2012	355	321	376	334	334	404	357	421	455	373	319	276
Maximum Regulation Up capacity (MW) – 2006	268	263	261	259	248	256	245	224	216	207	202	204
Maximum Regulation Down capacity (MW) – 2012	(238)	(249)	(237)	(241)	(257)	(285)	(306)	(329)	(304)	(320)	(286)	(291)
Maximum Regulation Down capacity (MW) – 2006	(236)	(243)	(236)	(241)	(242)	(245)	(254)	(315)	(308)	(312)	(318)	(340)

Table A-4: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	3,538	3,718	3,737	3,661	3,592	3,535	3,213	3,415	3,502	3,286	3,505	3,362
Maximum load-following up capacity (MW) – 2006	2,933	2,944	2,883	2,916	3,053	2,964	2,757	2,712	2,969	2,960	2,986	2,937
Maximum load-following down capacity (MW) – 2012	(3,031)	(3,570)	(3,308)	(3,479)	(3,013)	(3,908)	(3,927)	(3,579)	(3,675)	(3,338)	(3,934)	(3,962)
Maximum load-following down capacity (MW) – 2006	(2,567)	(2,649)	(2,751)	(2,718)	(2,601)	(3,046)	(3,107)	(2,989)	(2,866)	(2,918)	(3,262)	(3,365)
Maximum Regulation Up capacity (MW) – 2012	260	261	270	257	280	361	383	287	291	319	350	344
Maximum Regulation Up capacity (MW) – 2006	202	198	191	198	201	226	244	239	238	262	273	278
Maximum Regulation Down capacity (MW) – 2012	(341)	(408)	(461)	(463)	(506)	(763)	(305)	(321)	(312)	(294)	(275)	(229)
Maximum Regulation Down capacity (MW) – 2006	(367)	(408)	(430)	(434)	(416)	(305)	(267)	(268)	(289)	(245)	(223)	(222)

Table A-5: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,782	2,777	2,765	2,522	2,701	2,843	2,746	2,773	3,326	2,976	3,050	2,846
Maximum load-following up capacity (MW) – 2006	2,232	2,221	2,138	2,165	2,060	2,276	2,389	2,084	2,310	2,345	2,316	2,269
Maximum load-following down capacity (MW) – 2012	(2,904)	(3,004)	(2,724)	(2,845)	(2,699)	(2,960)	(2,794)	(3,210)	(3,103)	(2,879)	(2,661)	(3,058)
Maximum load-following down capacity (MW) – 2006	(2,268)	(2,280)	(2,275)	(2,132)	(2,171)	(2,344)	(2,509)	(2,396)	(2,228)	(2,145)	(2,129)	(2,058)
Maximum Regulation Up capacity (MW) – 2012	314	345	313	311	323	428	340	303	351	378	293	285
Maximum Regulation Up capacity (MW) – 2006	271	275	245	245	248	235	239	235	217	214	224	234
Maximum Regulation Down capacity (MW) – 2012	(252)	(275)	(257)	(281)	(274)	(297)	(333)	(372)	(407)	(328)	(352)	(427)
Maximum Regulation Down capacity (MW) – 2006	(233)	(263)	(244)	(240)	(249)	(256)	(259)	(263)	(304)	(335)	(323)	(371)

Table A-6: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,959	2,917	3,027	2,938	2,735	3,017	3,056	2,733	2,699	2,740	3,011	2,726
Maximum load-following up capacity (MW) – 2006	2,287	2,225	2,432	2,418	2,185	2,209	2,680	2,216	2,185	2,294	2,433	2,314
Maximum load-following down capacity (MW) – 2012	(2,579)	(2,904)	(3,176)	(2,890)	(3,172)	(3,247)	(3,031)	(2,787)	(2,820)	(2,720)	(2,992)	(2,894)
Maximum load-following down capacity (MW) – 2006	(2,048)	(2,132)	(2,133)	(2,249)	(2,131)	(2,217)	(2,307)	(2,060)	(2,232)	(2,305)	(2,482)	(2,420)
Maximum Regulation Up capacity (MW) – 2012	281	273	286	319	378	404	288	297	339	307	316	323
Maximum Regulation Up capacity (MW) – 2006	221	225	222	217	232	236	233	236	256	262	259	272
Maximum Regulation Down capacity (MW) – 2012	(392)	(377)	(454)	(388)	(376)	(515)	(390)	(347)	(257)	(275)	(329)	(247)
Maximum Regulation Down capacity (MW) – 2006	(420)	(440)	(406)	(402)	(395)	(263)	(270)	(254)	(248)	(230)	(230)	(232)

Table A-7: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,338	2,753	2,344	2,698	2,532	2,541	2,838	2,598	2,631	2,700	2,803	2,710
Maximum load-following up capacity (MW) – 2006	1,999	2,037	1,984	2,132	2,171	2,095	2,370	2,015	2,153	2,168	2,048	2,097
Maximum load-following down capacity (MW) – 2012	(2,849)	(2,934)	(2,533)	(2,324)	(2,669)	(2,533)	(2,598)	(2,480)	(2,554)	(2,468)	(2,574)	(2,398)
Maximum load-following down capacity (MW) – 2006	(2,176)	(2,124)	(2,120)	(2,051)	(2,095)	(2,107)	(2,138)	(1,926)	(1,897)	(1,813)	(1,940)	(1,875)
Maximum Regulation Up capacity (MW) – 2012	319	284	304	334	327	448	255	263	335	300	298	302
Maximum Regulation Up capacity (MW) – 2006	274	249	249	248	235	230	240	237	240	233	222	231
Maximum Regulation Down capacity (MW) – 2012	(288)	(298)	(265)	(277)	(293)	(306)	(349)	(338)	(357)	(442)	(378)	(383)
Maximum Regulation Down capacity (MW) – 2006	(237)	(248)	(246)	(251)	(249)	(264)	(262)	(263)	(270)	(353)	(314)	(327)

Table A-8: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,597	2,619	3,000	2,688	2,689	3,063	2,683	2,608	2,646	2,516	2,647	2,647
Maximum load-following up capacity (MW) – 2006	2,171	1,965	2,256	2,175	2,146	2,624	2,193	2,131	2,071	2,222	2,285	2,201
Maximum load-following down capacity (MW) – 2012	(2,424)	(2,666)	(2,613)	(2,448)	(3,013)	(3,094)	(2,655)	(2,380)	(2,298)	(2,482)	(2,754)	(2,612)
Maximum load-following down capacity (MW) – 2006	(1,837)	(2,069)	(1,989)	(1,947)	(2,097)	(2,424)	(2,244)	(1,907)	(1,934)	(1,998)	(2,303)	(2,204)
Maximum Regulation Up capacity (MW) – 2012	284	296	302	328	397	474	326	303	304	315	308	329
Maximum Regulation Up capacity (MW) – 2006	238	234	229	232	219	220	233	247	260	263	265	273
Maximum Regulation Down capacity (MW) – 2012	(397)	(377)	(407)	(391)	(374)	(363)	(304)	(313)	(296)	(274)	(297)	(289)
Maximum Regulation Down capacity (MW) – 2006	(306)	(320)	(319)	(336)	(322)	(289)	(280)	(279)	(261)	(232)	(233)	(240)

APPENDIX A-2: Additional sensitivity results from the operational requirements simulations

This appendix provides additional sensitivity results from the operational requirements simulations. As noted in Section 3, these include:

- Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio; and the

- Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors.

As with Section 3, the focus in this appendix is on Summer 2012 results; showing one season of such results is sufficient to characterize the relationships among the variables being analyzed.

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[2]

A.1 Load Following Results for Summer 2012

A.1.1 Requirements by renewable technology

As noted in Section 2, the impact of variable energy resources can be differentiated by technology using the statistical simulation methodology. The results of such sensitivity analyses are presented here to show the relative impact of load and each renewable technology being modeled on load following by hour. The difference between wind and solar is in part a function of the capacity of each technology type in the portfolio (i.e., how much energy is being obtained in each hour from each technology), and also of their particular variability and forecast error characteristics. The results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts; that is, there is not sufficient information in these results to determine how to isolate the relative impacts of wind and solar across all the operational requirements. As with the results shown above, the results here assume all forecast errors.

Figures A-9 and A-10 show the hourly maximum results due to (a) load, (b) load plus solar, (c) load plus wind, and (d) load plus wind plus solar. Obviously, in the off-peak hours, wind is the driver of the incremental operational requirements.

[2] That is, excluding the 5% highest results from the simulations.

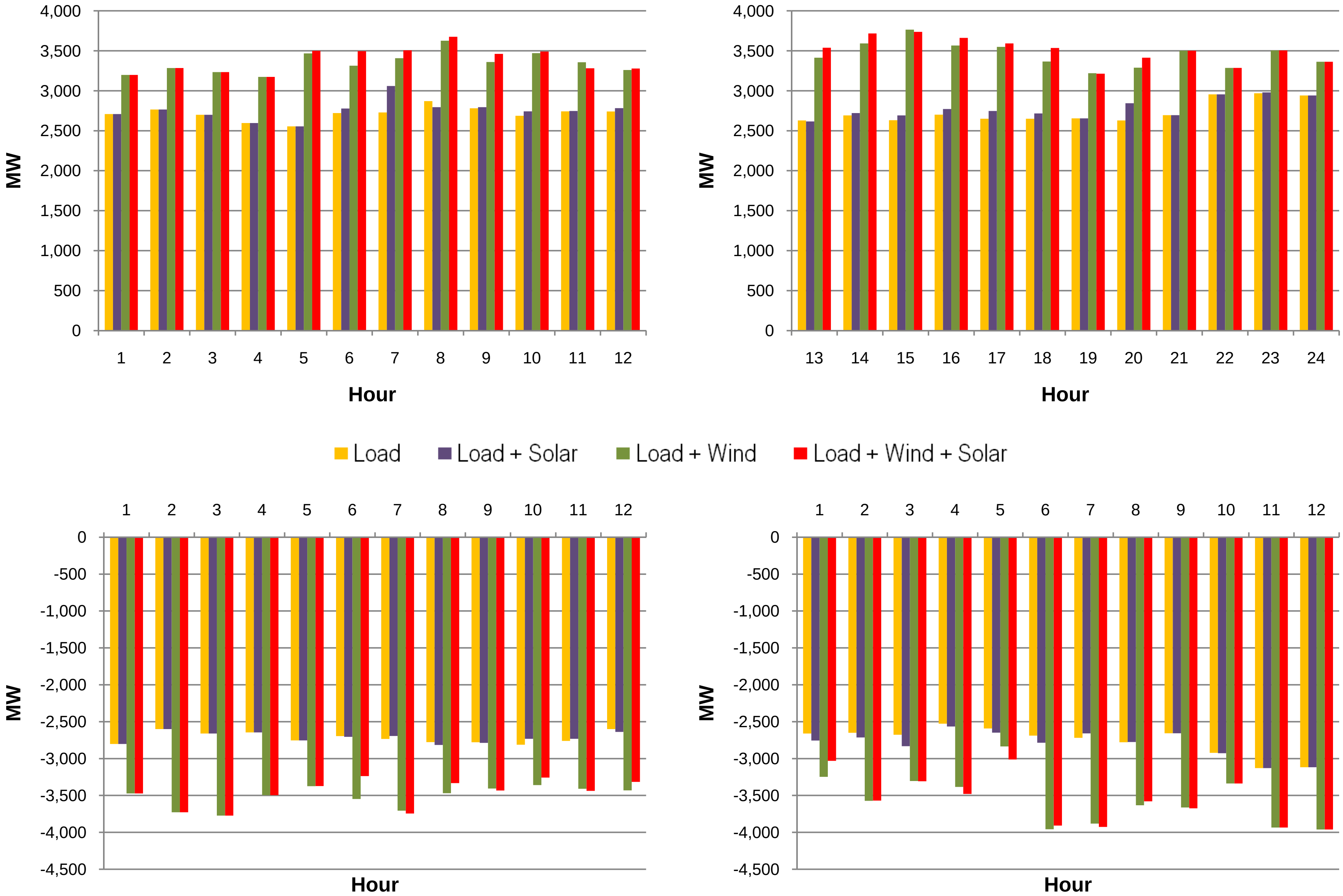


Figure A-9: 2012 Summer Load Following Maximum Hourly Requirement by Technology

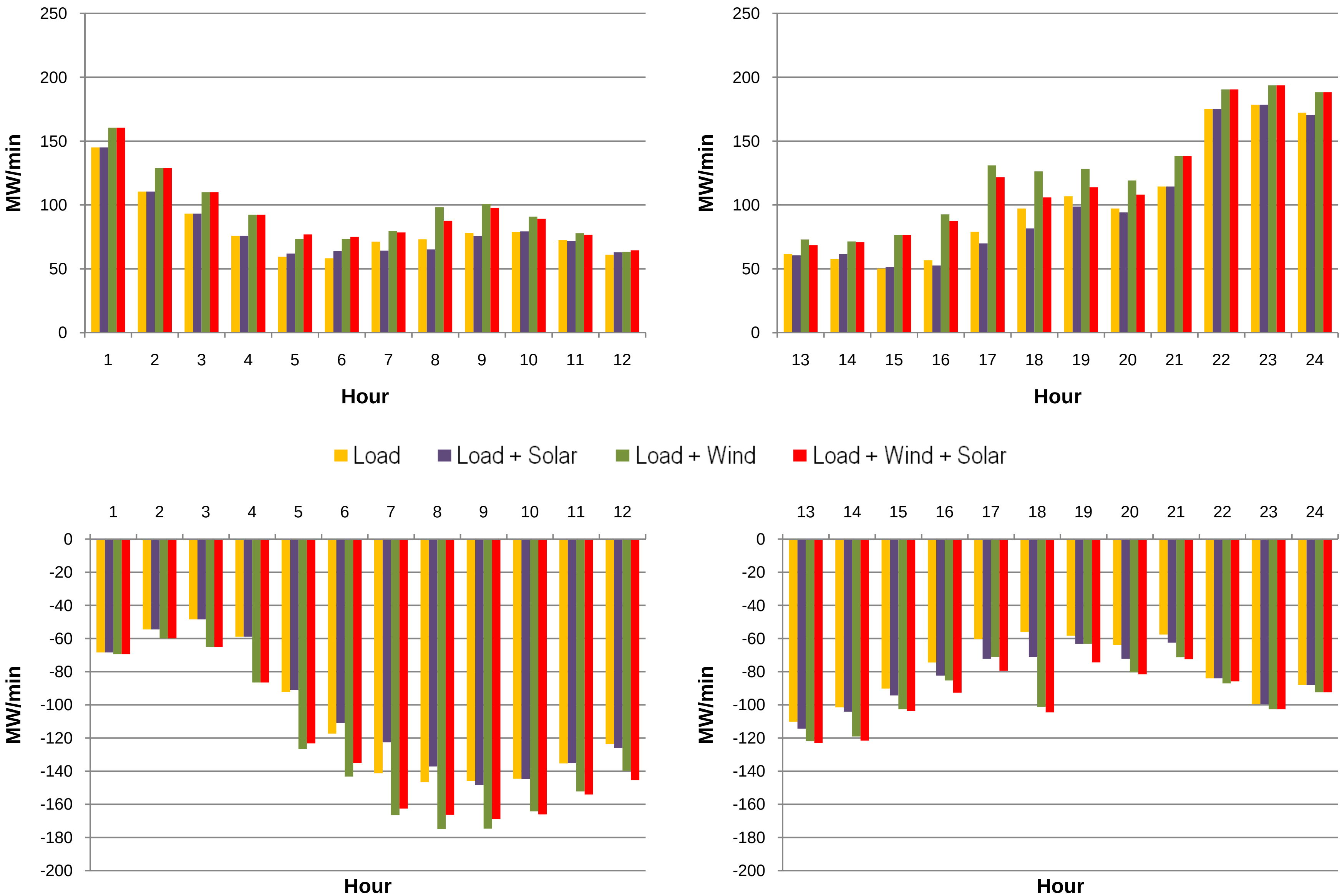


Figure A-10: 2012 Summer Load Following Up and Down Maximum Hourly Ramp Rate by Technology

A.1.2 Impact of forecast error and variability

In the hour-ahead time frame, forecast error is the more significant contributor to incremental load following requirements due to variable energy resources than their inherent variability. As noted, the simulation can take account of this difference by altering the statistical parameters of the distribution of forecast errors – including removing them altogether, at which point the residual impact on load following is due to variability alone. For comparison, this section compares the results of including all forecast errors and no errors; specific improvements in forecast errors were not evaluated in this study but will be explored in subsequent analysis.

The two components of Figure A-11shows an aggregate "all hours" result that compares the load following up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes 19 percent of the total requirement, with forecast errors providing the remaining 81 percent. Figures A-12 and A-13 then show this result by operating hour. The hourly result shows in which hours improvements in forecasting are likely to provide the highest benefit.

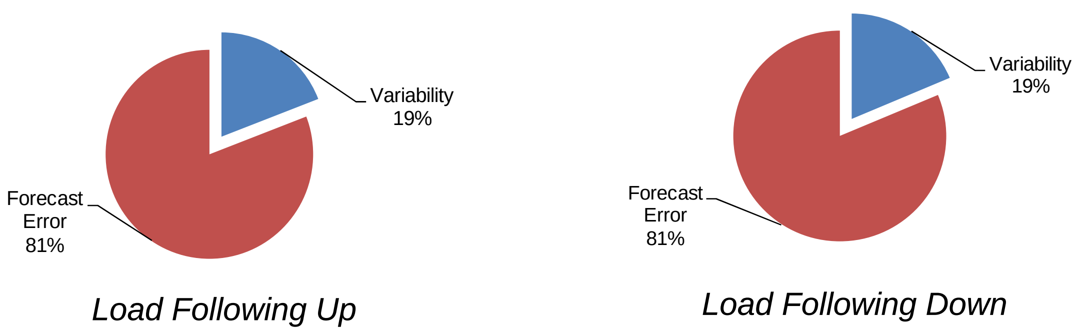


Figure A-11: Aggregate Contribution of Variability and Forecast Error to the Summer 2012 Load Following Requirement

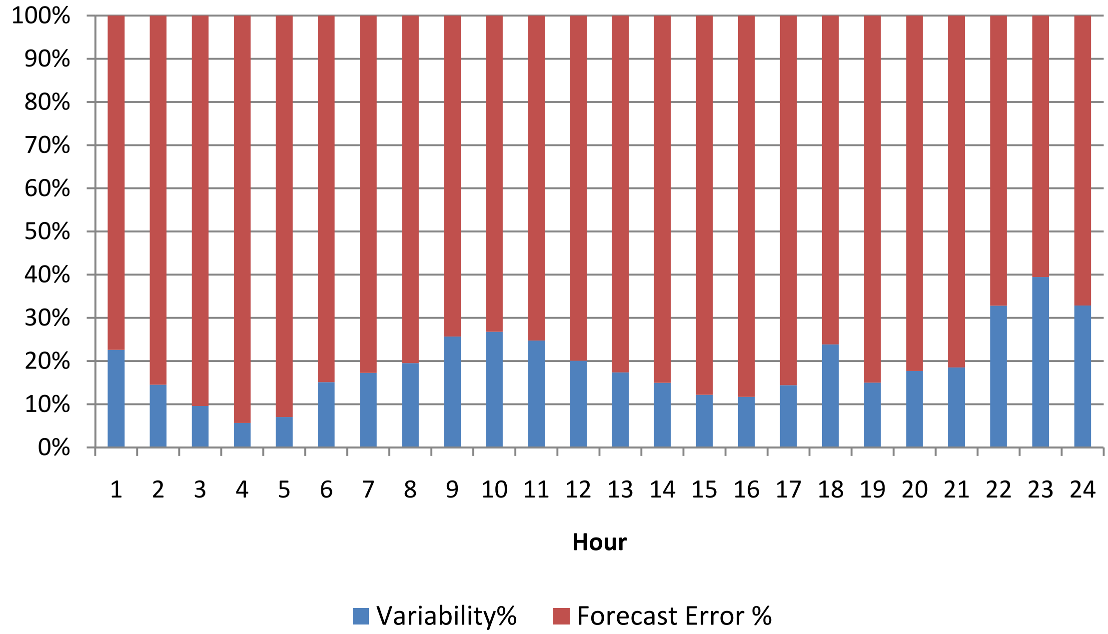


Figure A-12: Effect of Forecast Error and Variability on Load Following Up (Load & Wind & Solar) by Hour, Summer 2012

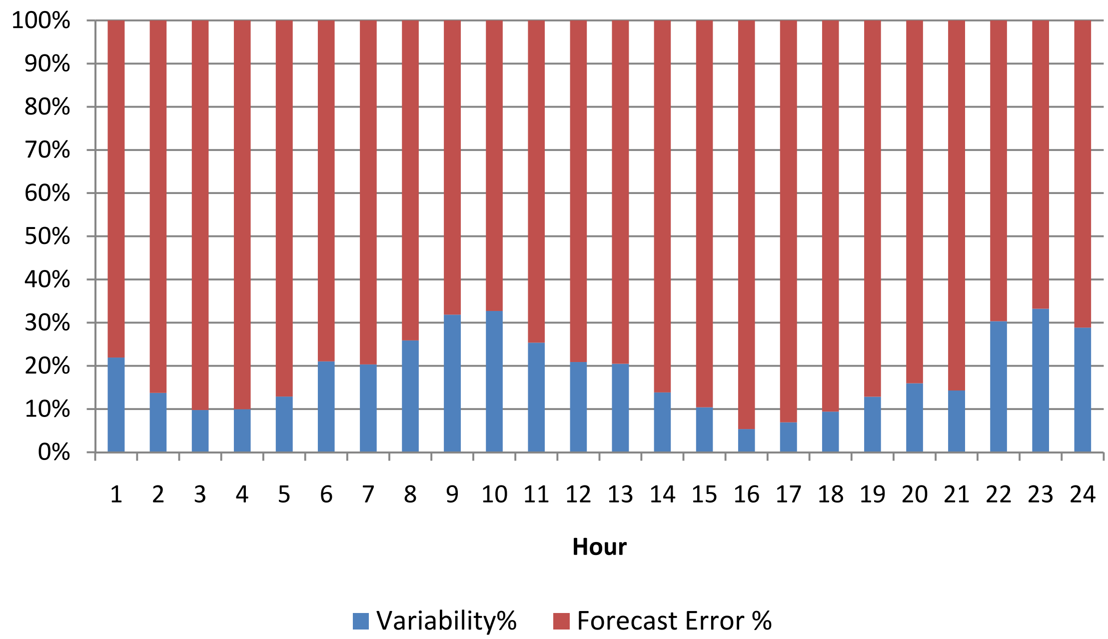


Figure A-14: Effect of Forecast Error and Variability on Load Following Down (Load & Wind & Solar) by Hour, Summer 2012

A further representation of this result is shown in Figure A-14, which compares the maximum load following capacity results for load-only requirements assuming all (load forecast) errors to portfolio requirements with wind and solar forecast errors eliminated and then to portfolio requirements with wind and solar forecast errors included.

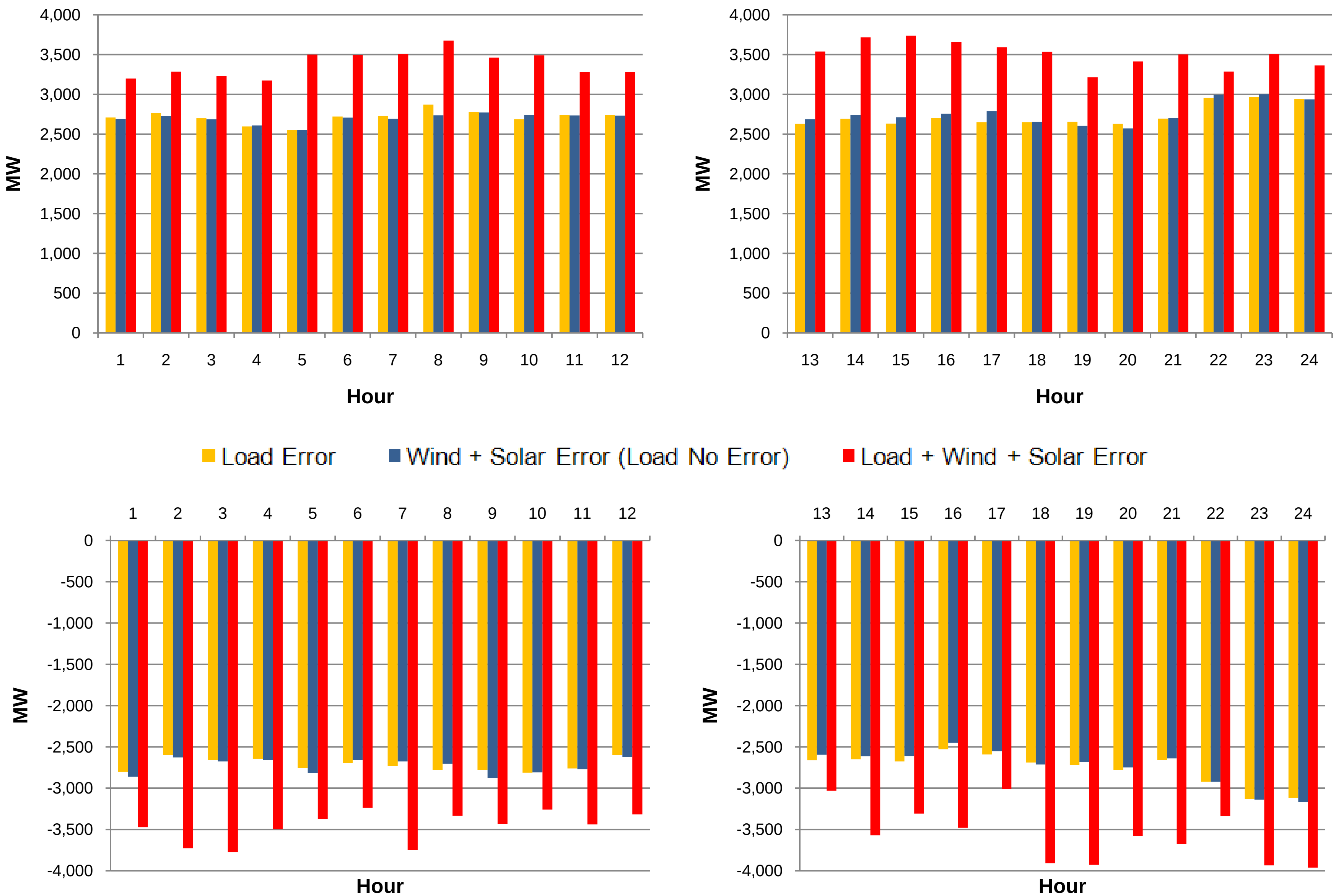


Figure A-13: Maximum Hourly Load-Following Capacity Requirement with Variations in Forecast Error Assumptions

The sensitivity analysis of forecast error provides a quantitative measure of how improvements in the hour-ahead forecast (and hence in periods further forward in time) can reduce the ramp range that the ISO will need to deploy within the hour. A 10 percent improvement in forecast error could result in a reduction in several hundred MW of load following capability in the upward and downward direction. The results point to the particular hours – morning and evening ramps – where such forecast improvements would have the most value. However, the ISO has not in this study quantified specific reductions in forecast error or the potential dispatch cost reductions. Subsequent studies may provide such information.

A.2 Regulation Results for Summer 2012

A.2.1 Requirements by renewable technology

As with load following, the impact of variable energy resources on regulation can be differentiated by technology using the statistical simulation methodology. These sensitivity results are presented here to show the relative impact of load and each renewable technology (at the capacity being modeled) on regulation by hour. Again, the results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts. The results here assume all forecast errors and variability for load, but only the variability data captured for wind and solar. Hence, the results are not indicative of how variable energy resource forecast error affects the operational requirements in this time frame.

Figure A-15 shows the hourly maximum Regulation capacity results with sensitivity cases that model (a) load only for 2012, (b) load plus solar, (c) load plus wind, and, finally, (d) load plus wind plus solar, which is the case shown in Section 3. The results show that wind resources largely drive the increases in regulation up requirements in the morning hours, while solar resources barely increase those requirements compared to the load-only case. In the afternoon hours, solar resources drive additional requirements in the mid-afternoon hours, when wind is hardly creating any additional requirements until hours 18-19. For regulation down, solar has a more significant effect than wind in Hours 8-9, then wind significantly drives the maximum requirements in the mid-afternoon, with a peak in Hour 18. Figure A-16 shows these comparative results for the hourly maximum results for Regulation ramp rates.

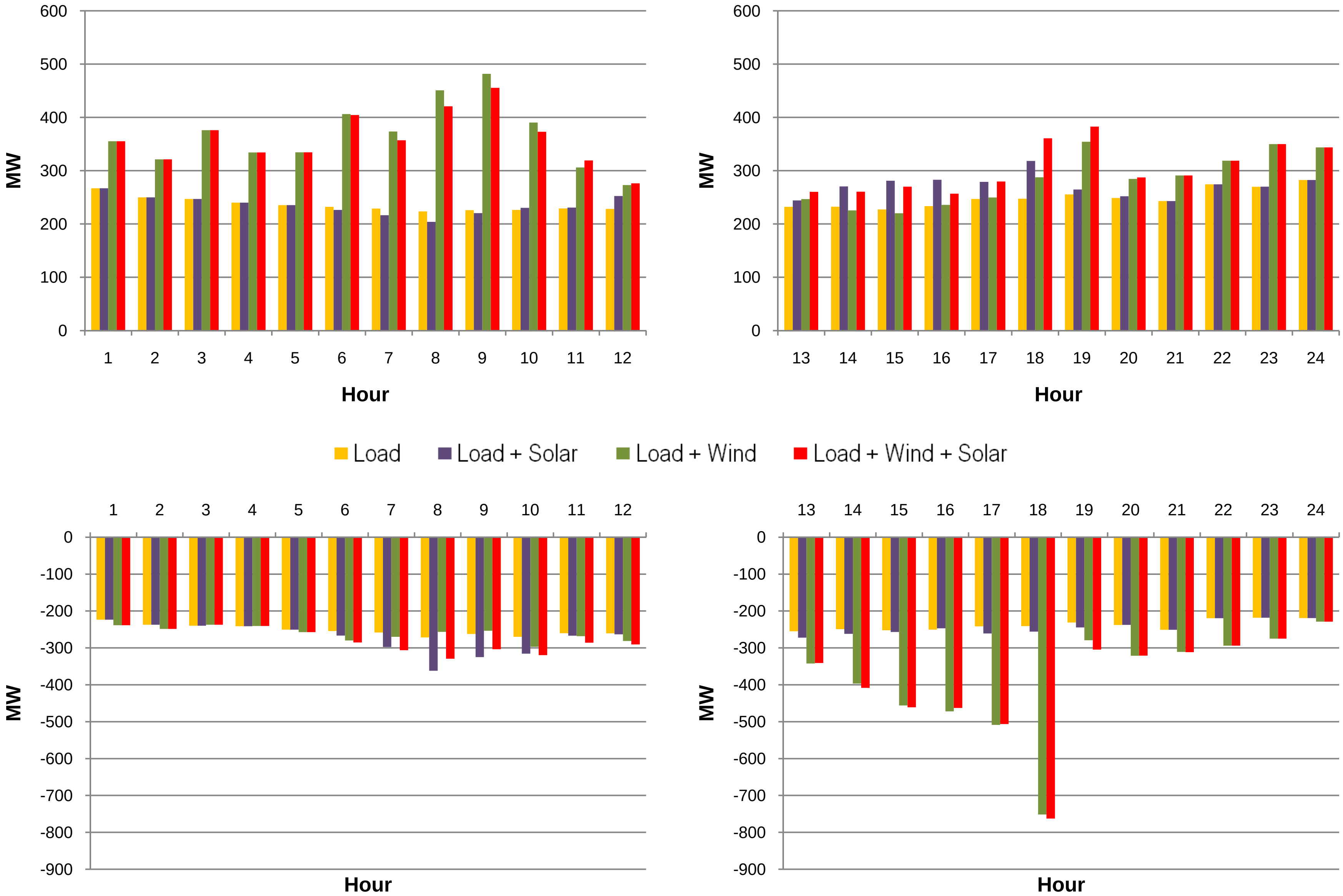


Figure A-14: Regulation Capacity Requirements by Technology by Hour, Summer 2012

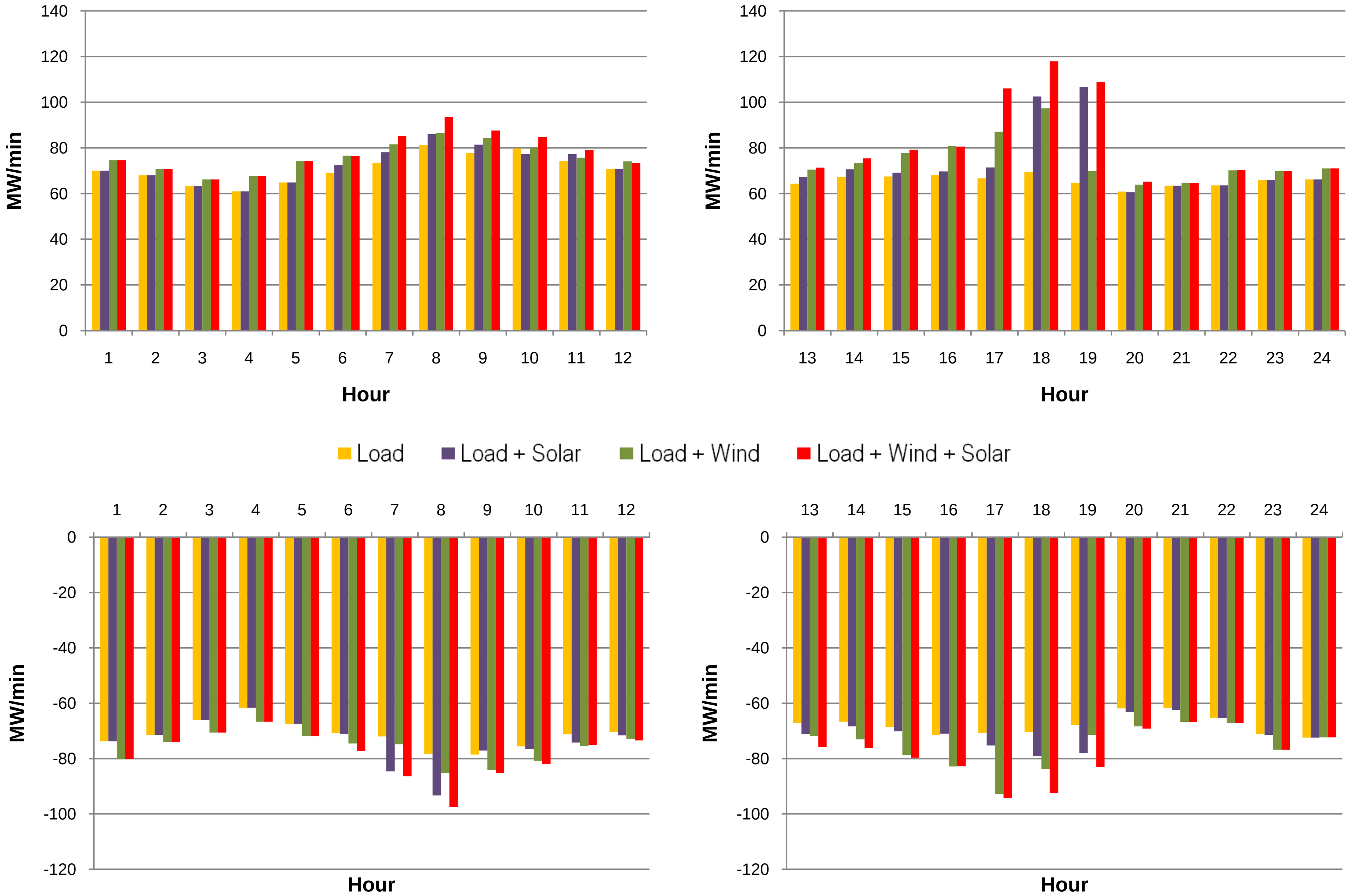


Figure A-15: Summer 2012 Regulation Ramp Rate by Technology

A.2.2 Impact of forecast error and variability

In the hour-ahead time frame, variability is the more significant contributor to the incremental regulation requirements due to variable energy resources than forecast error. However, unlike the load following simulation, the model does not include short-term forecast errors for wind and solar resources; in current practice, the ISO uses a persistence forecast for short-term dispatch, which was not sampled by the Monte Carlo simulation but rather held static in the analysis. Hence, only load forecast errors are evaluated when isolating forecast error from variability, and the impact of wind and solar resources on Regulation is based entirely on their variability within the five-minute dispatch interval.

Figure A-17 shows an aggregate "all hours" result that compares the regulation up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes a little over 60 percent of the total requirement; with (load) forecast errors providing the remaining percent. Figure A-18 and Figure A-19 then shows this result by operating hour. The hourly results show which hours improvements in forecasting are likely to provide the highest benefit.

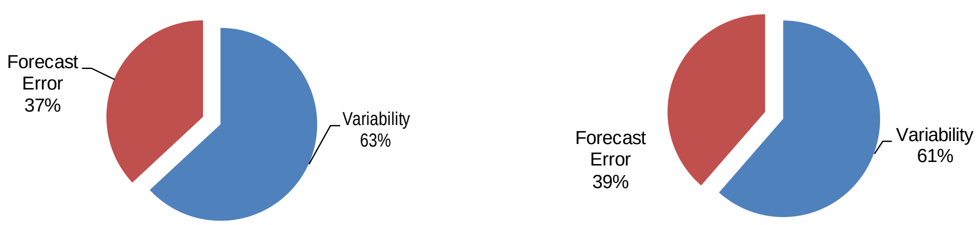


Figure A-16: Aggregate Contribution of Variability and Forecast Error to the Summer Regulation Requirement

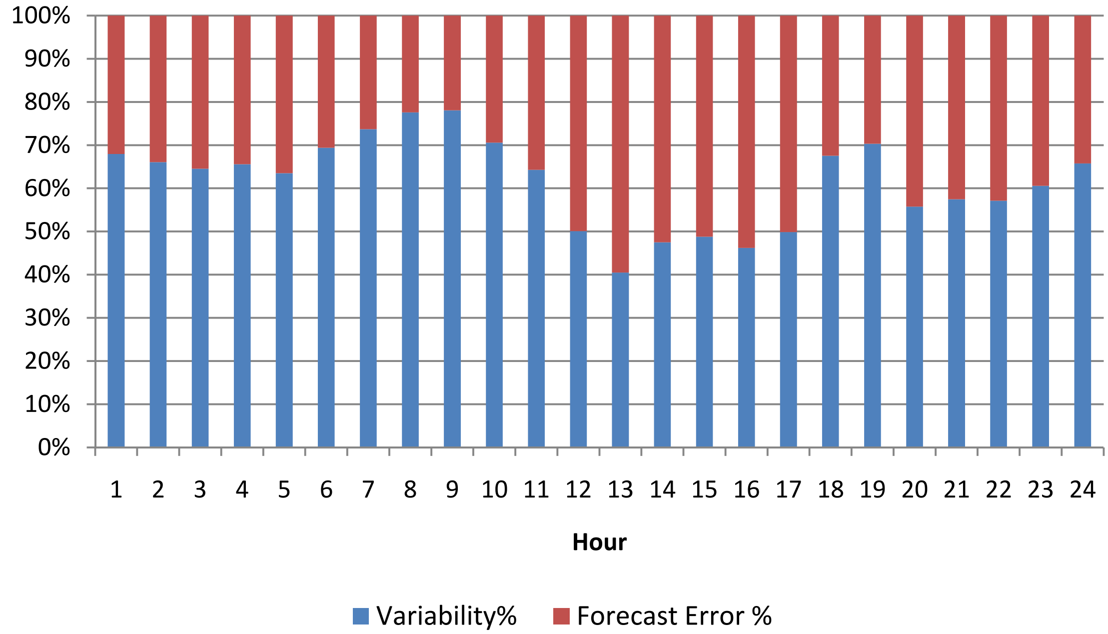


Figure A-17: Effect of Forecast Error and Variability on Regulation Up (Load & Wind & Solar) by Hour, Summer 2012

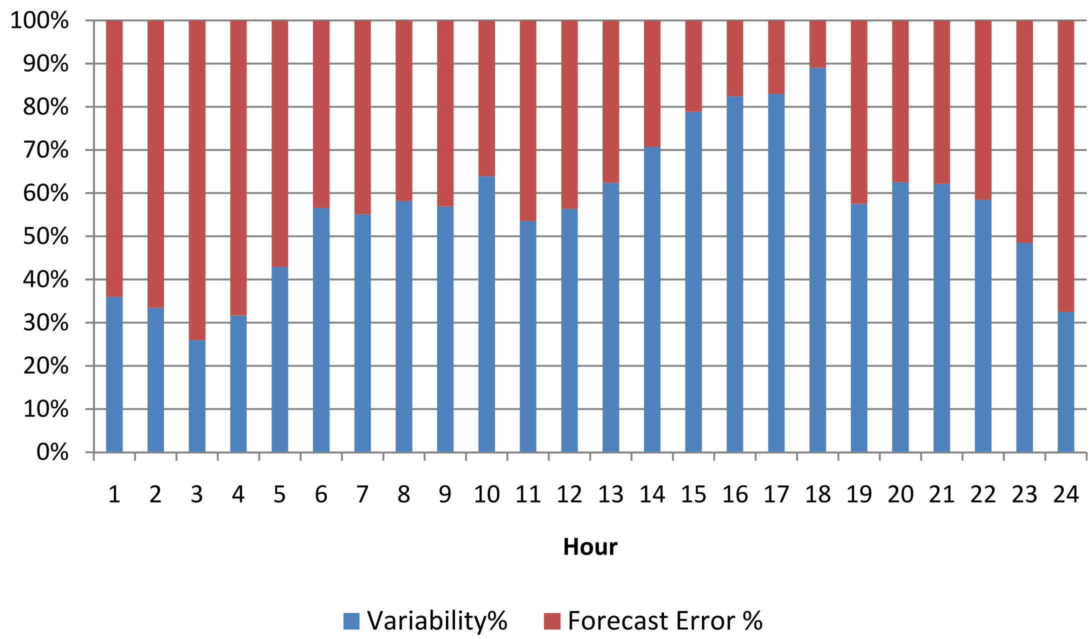


Figure A-18: Effect of Forecast Error and Variability on Regulation Down (Load & Wind & Solar) by Hour, Summer 2012

APPENDIX B Additional Fleet Capability Analysis Results

Section 4 discussed the load-following and regulation capability of the fleet for the summer season based on market data from April 1, 2009 to June 30, 2010. This appendix gives the historical capability for all the seasons.

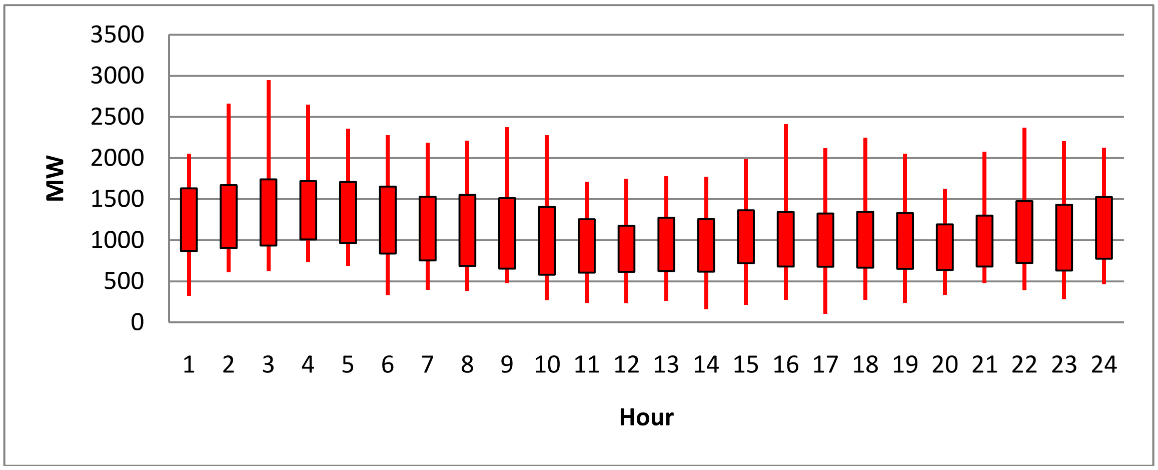


Figure B-1: Fall 5-Minute Load Following Up Capability: Sep2009-Nov2009

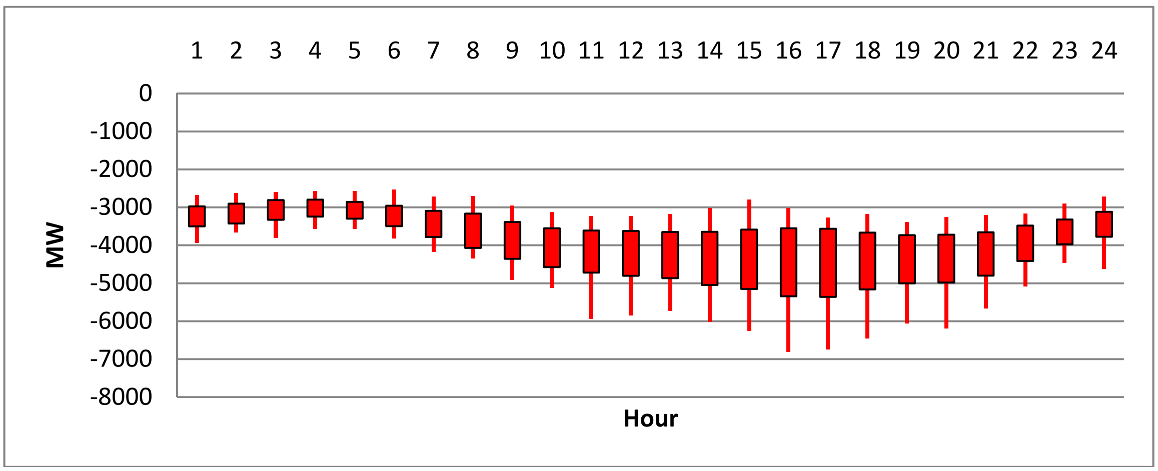


Figure B-2: Fall 5-Minute Load Following Down Capability: Sep2009-Nov2009

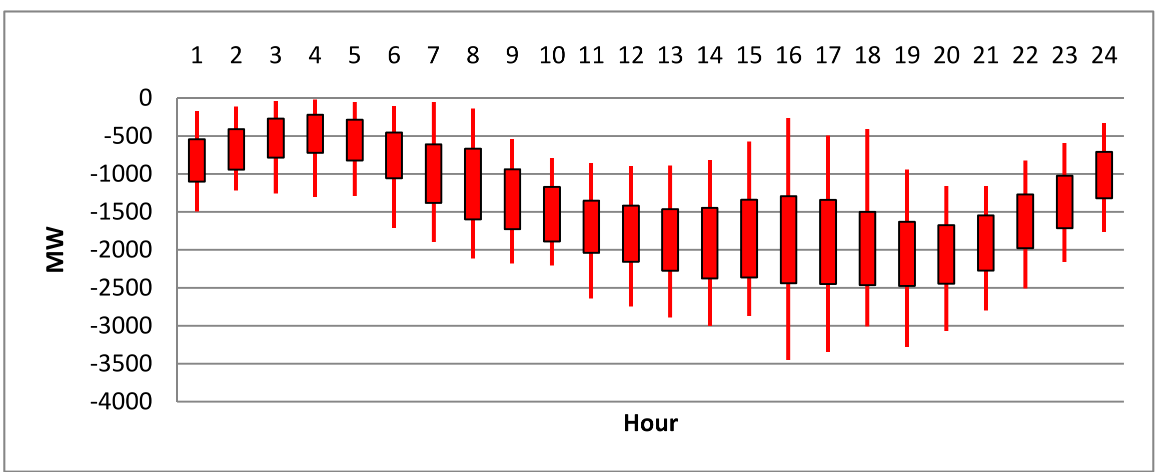


Figure B-3: Fall 5-Minute Load Following Down Capability (To Self Schedule): Sep2009-Nov2009

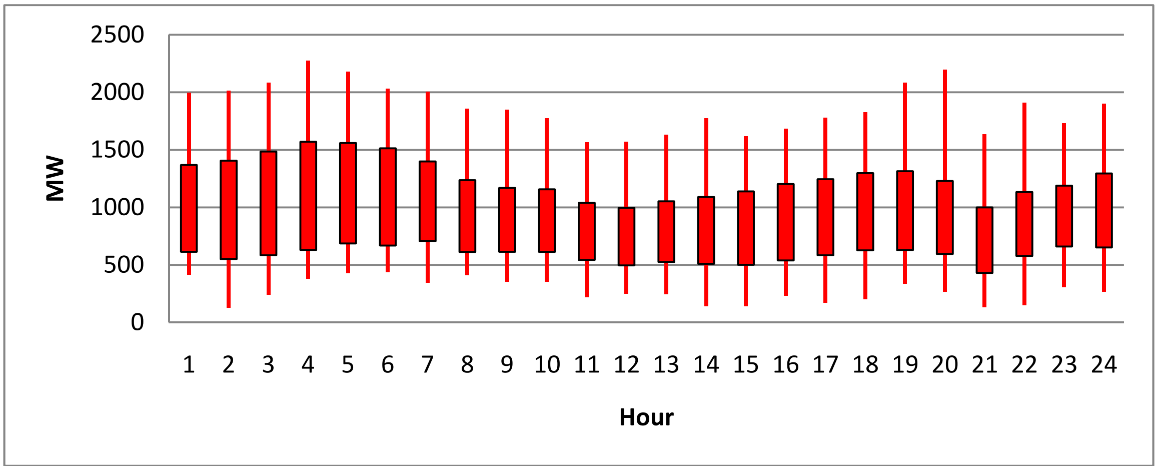


Figure B-4: Spring 5-Minute Load Following Up Capability: Mar-May, 2009-2010

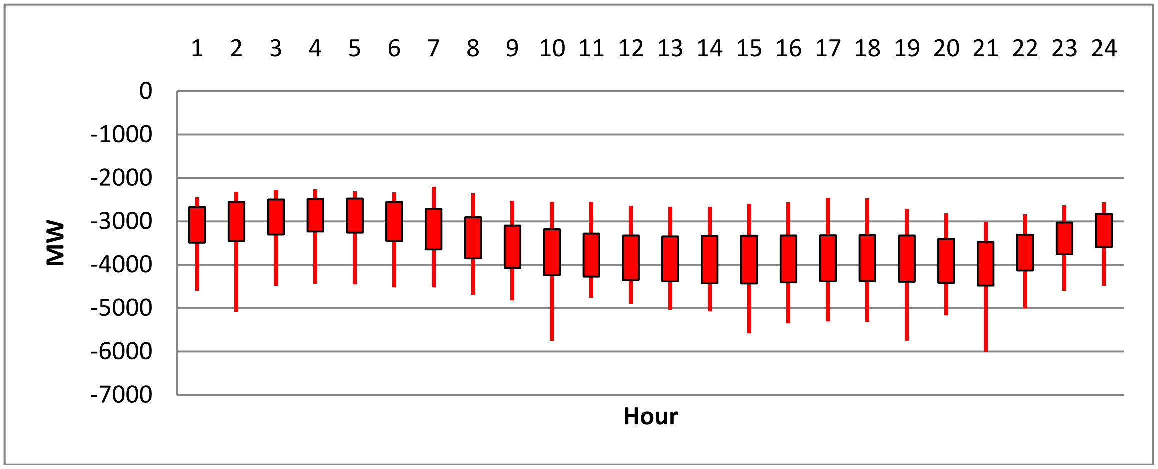


Figure B-5: Spring 5-Minute Load Following Down Capability: Mar-May, 2009-2010

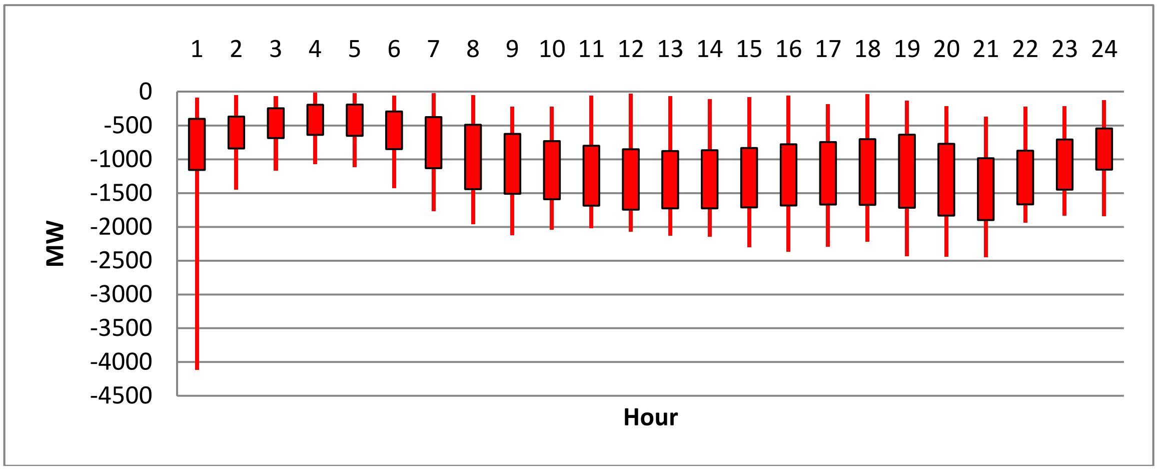


Figure B-6: Spring 5-Min Load Following Down Capability (To Self Schedule): Mar-May, 2009-2010

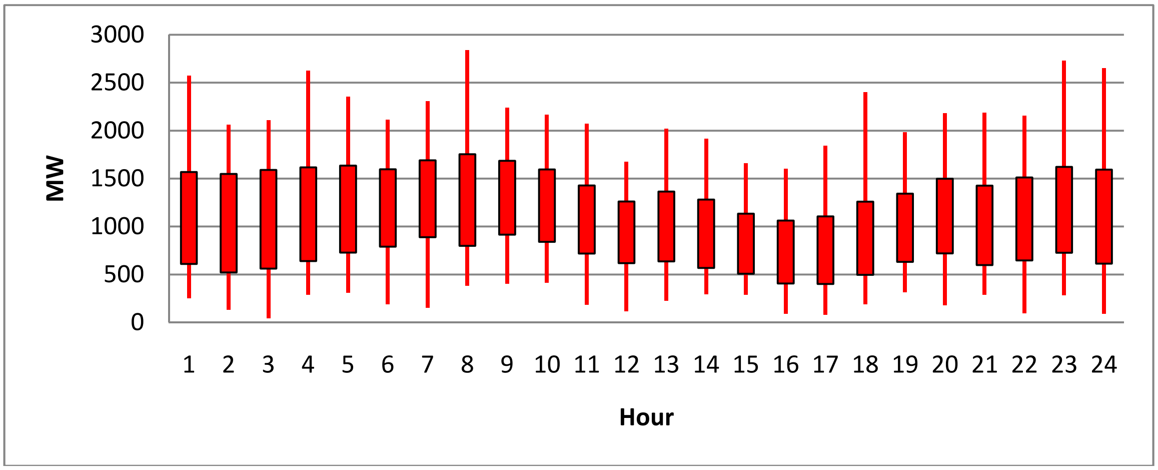


Figure B-7: Summer 5-Minute Load Following Up Capability: Jun2009-Aug2009, Jun2010

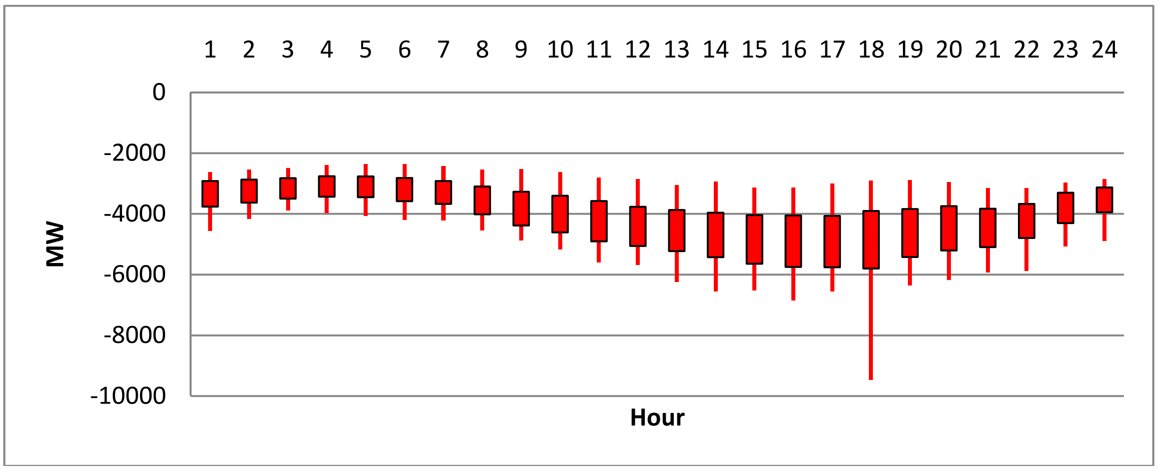


Figure B-8: Summer 5-Minute Load Following Down Capability: Jun2009-Aug2009, Jun2010

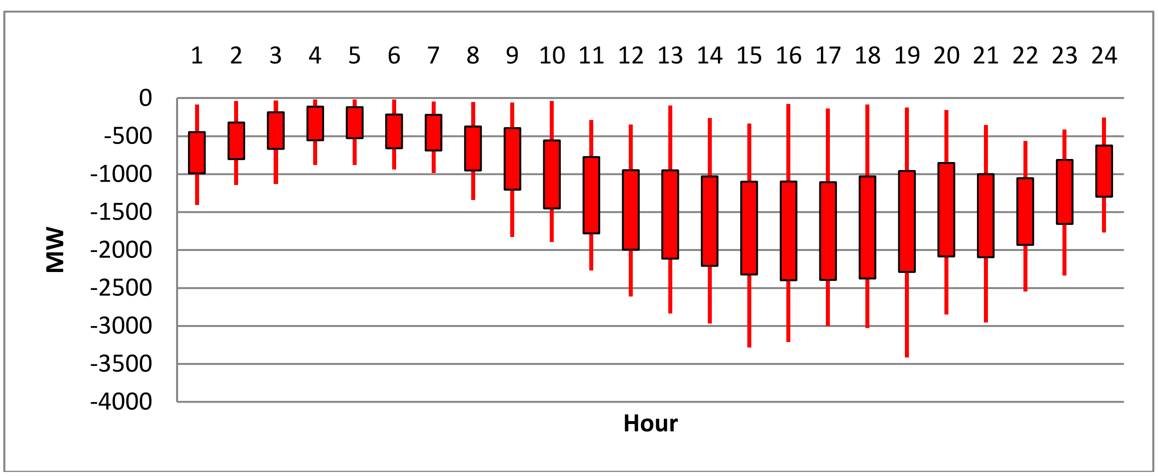


Figure B-9: Summer 5-Min Load Following Down Capability (To Self Schedule): Jun09-Aug09, Jun10

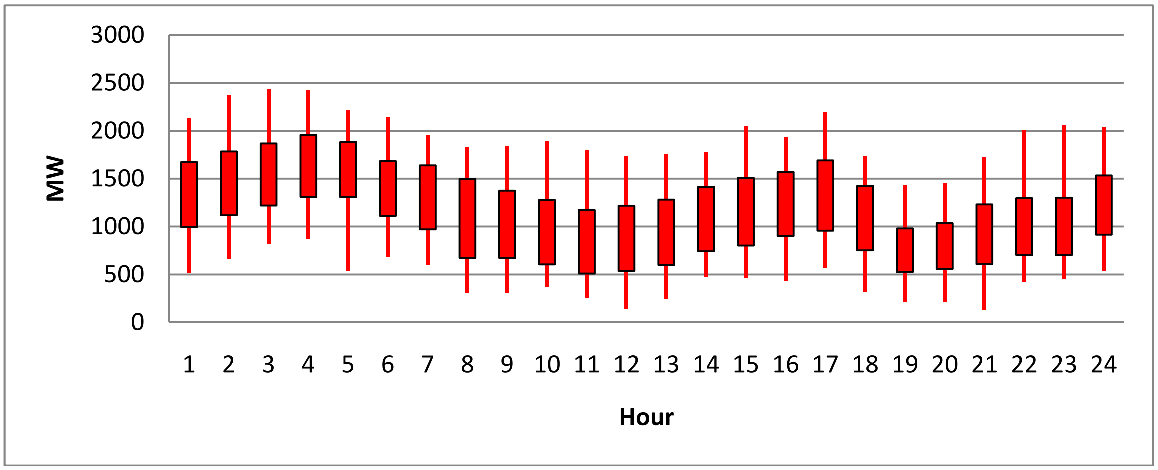


Figure B-10: Winter 5-Minute Load Following Up Capability: Dec2009-Feb2010

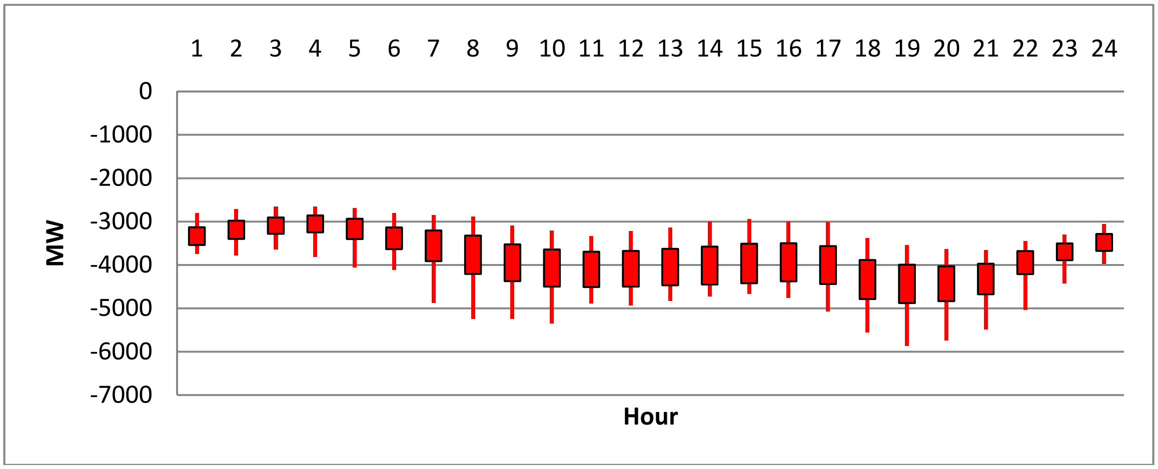


Figure B-11: Winter 5-Minute Load Following Down Capability: Dec2009-Feb2010

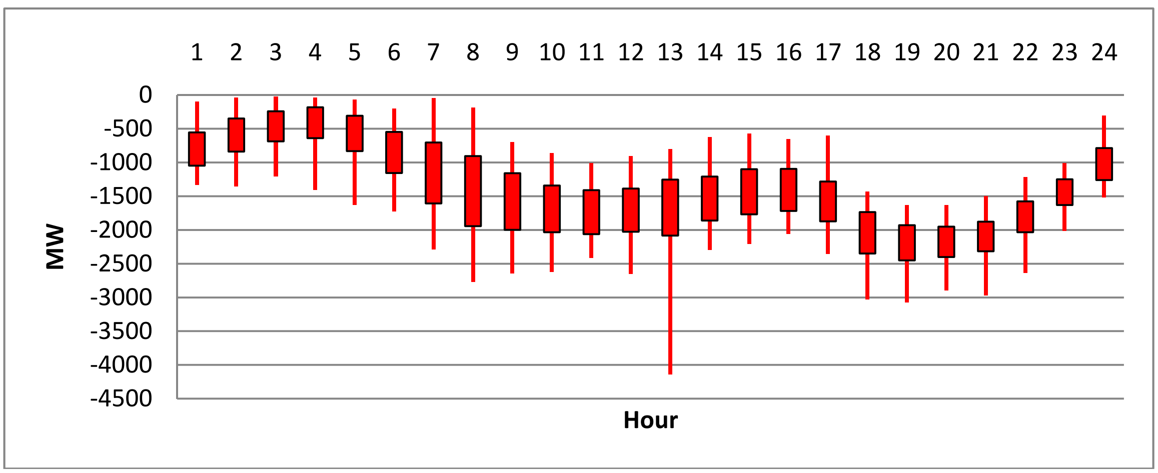


Figure B-12: Winter 5-Minute Load Following Down Capability (To Self Schedule): Dec2009-Feb2010

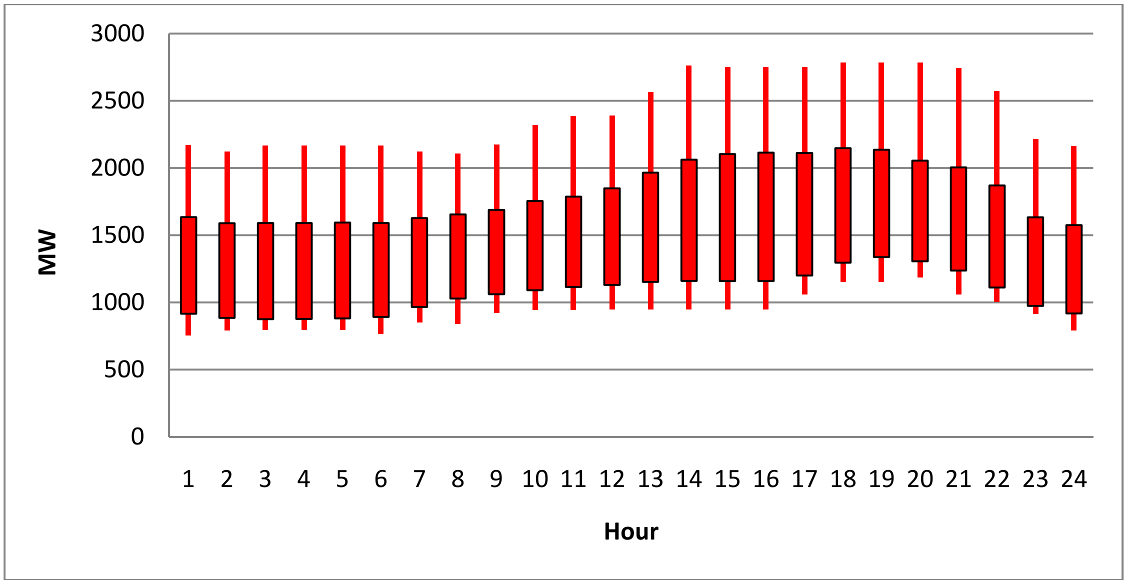


Figure B-13: Fall Regulation Up, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

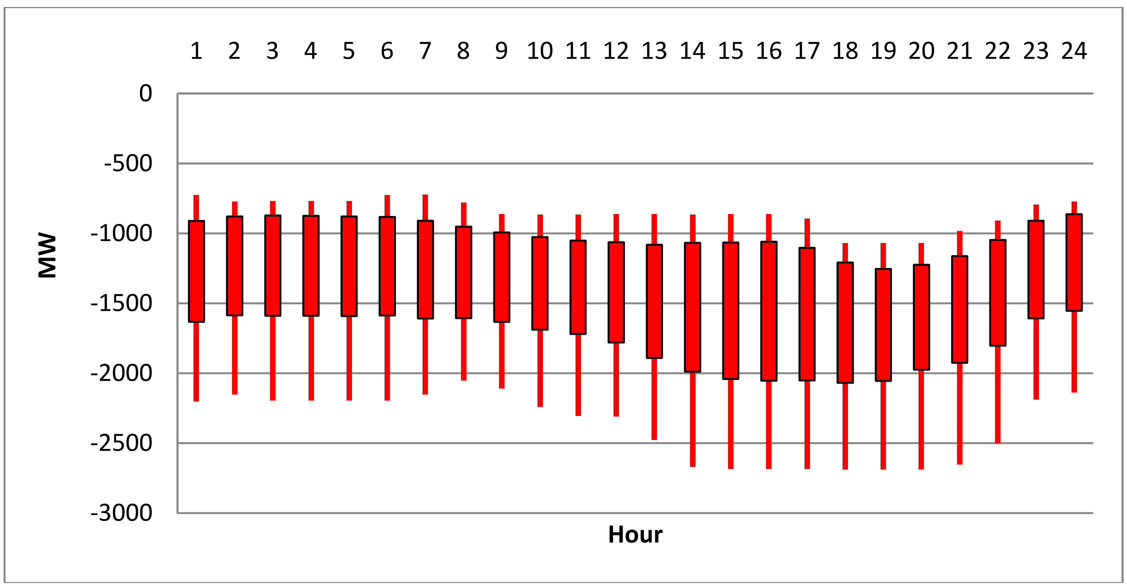


Figure B-14: Fall Regulation Down, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

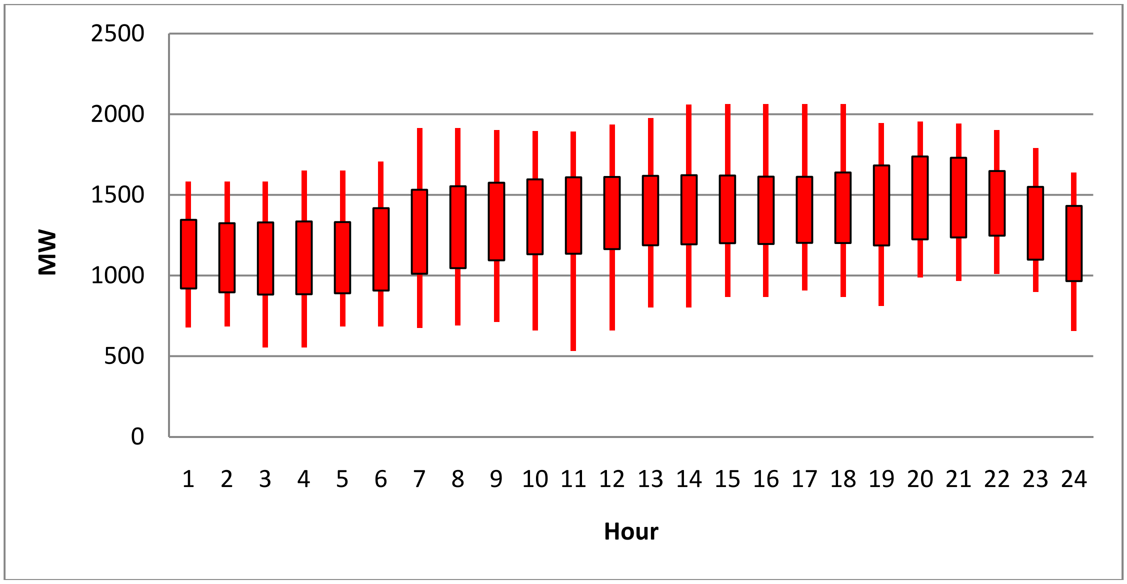


Figure B-15: Spring Regulation Up, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

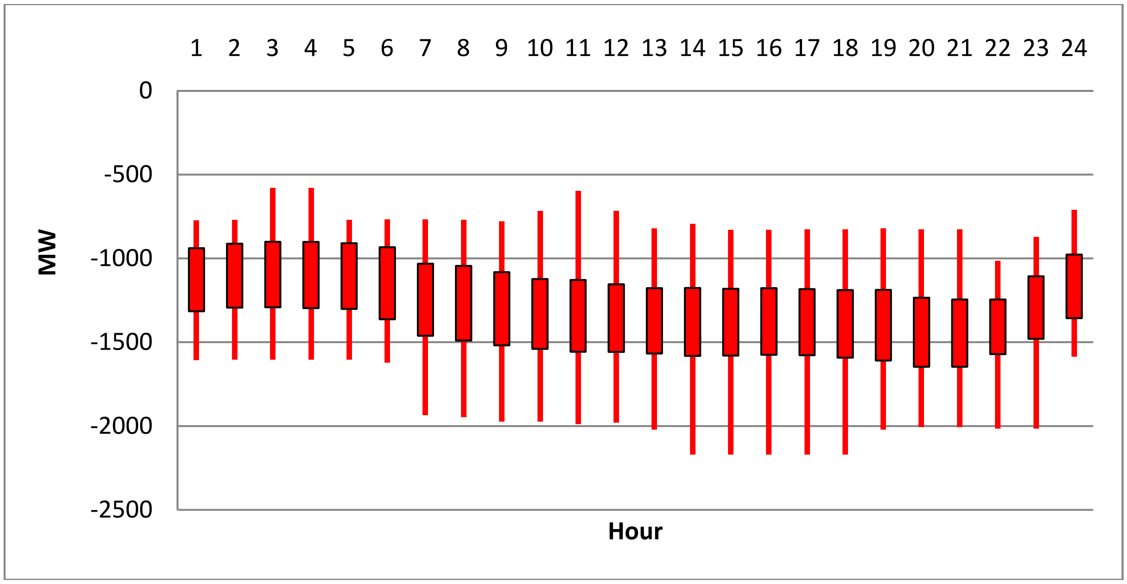


Figure B-16: Spring Regulation Down, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

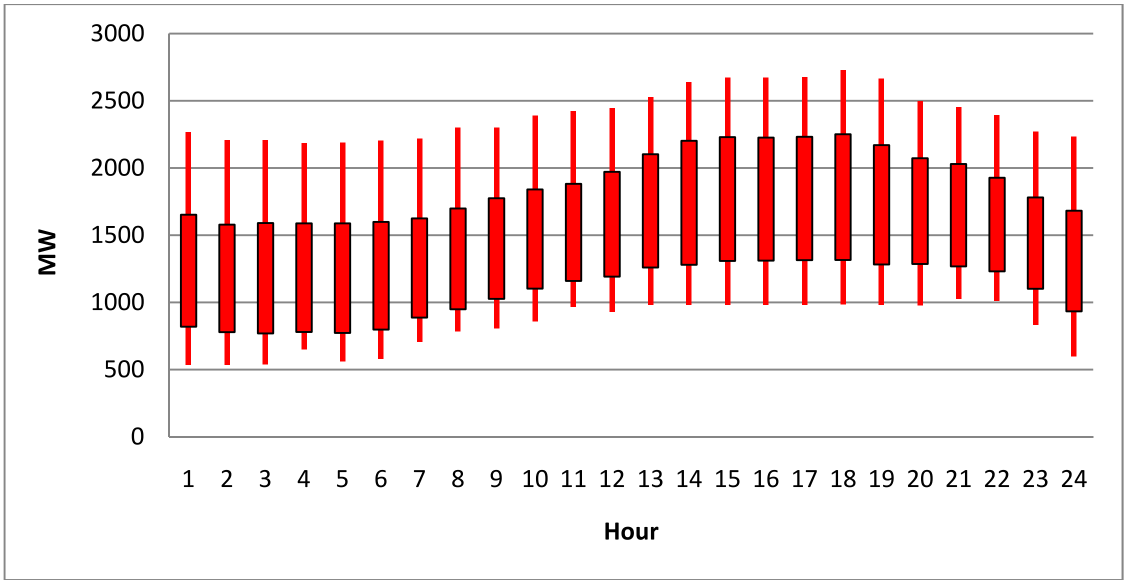


Figure B-17: Summer Regulation Up, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

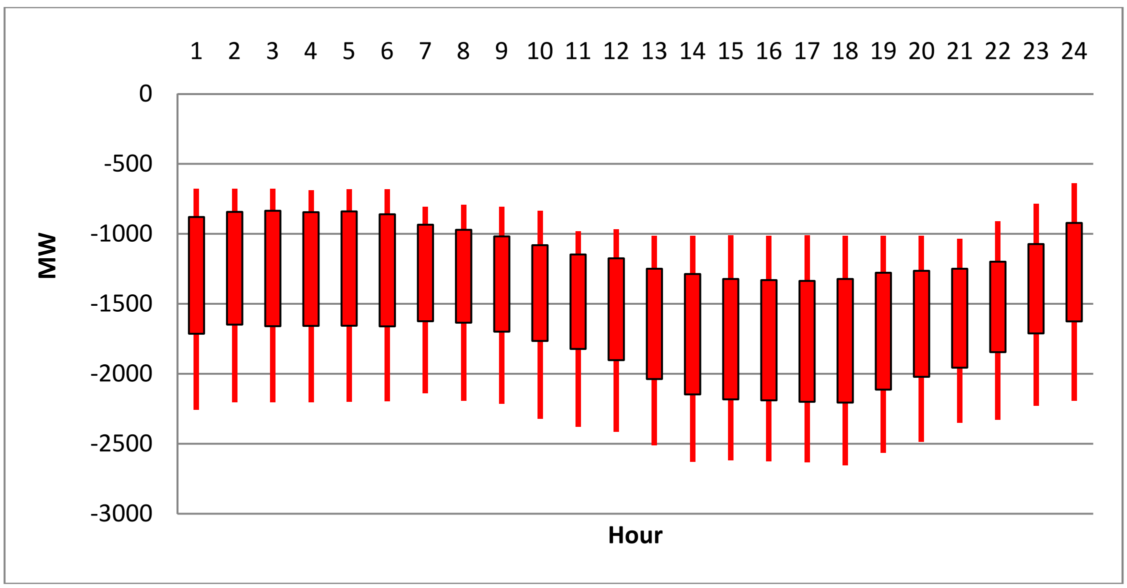


Figure B-18: Summer Regulation Down, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

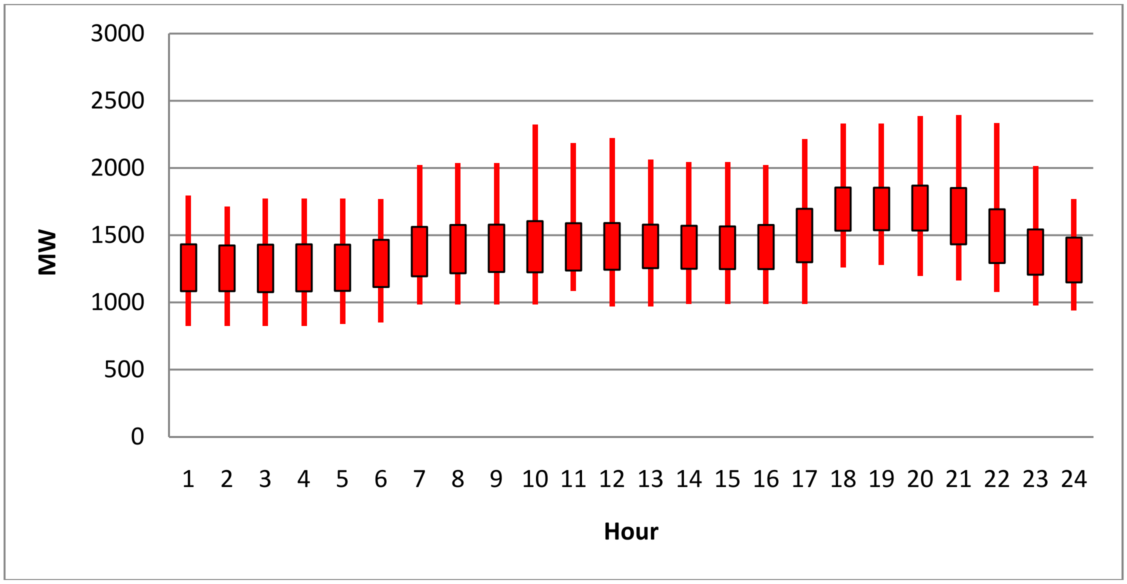


Figure B-19: Winter Regulation Up, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

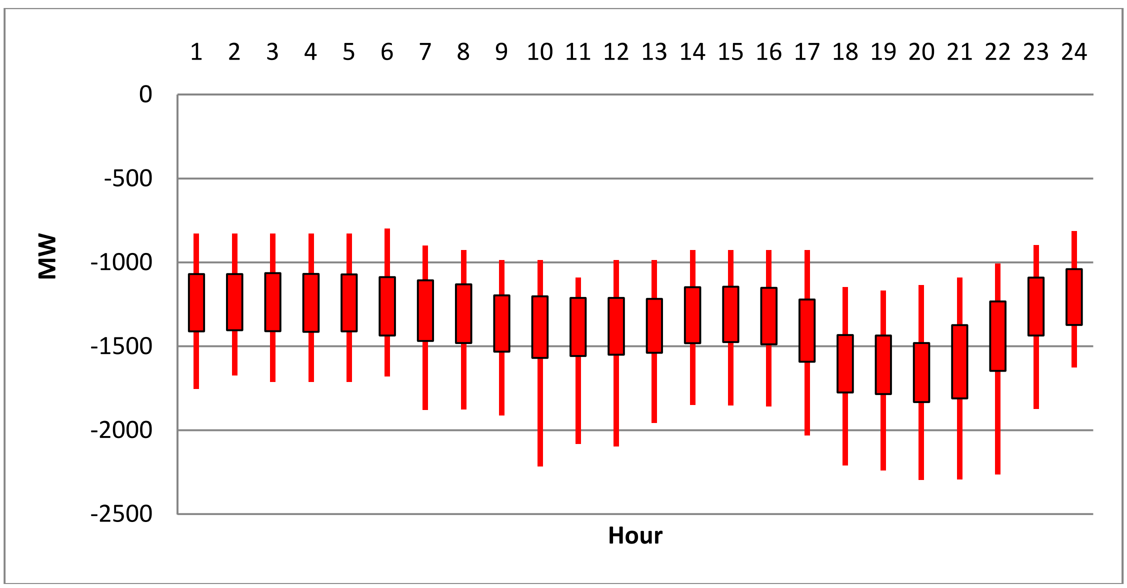


Figure B-20: Winter Regulation Down, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

APPENDIX C Additional Production simulation Results

C.1 Stochastic Sequential Simulation Results

C.1.1 Overview

For selected days, the ISO adopted a sequential approach to the simulations: first, conducting the day-ahead and hour-ahead simulations, then “freezing” the resulting unit commitment for simulation of the “real-time” dispatch on a five-minute time-step. This methodology is already described in the Technical Appendix. It is not practical to run the sequential, stochastic simulation, and in particular, the 5-minute real-time simulations for the whole year due to the computational burden that is involved. Therefore, it is necessary to focus these simulations only for some periods of interest. This section of the appendix describes the overall process that was used in the sequential, stochastic simulation of interesting days.

A number of stochastic simulations are required for determining the real-time operational capability of the system. These simulations are listed below.

- Annual Day Ahead (DA), stochastic
- Monthly Hour Ahead (HA), stochastic
- Monthly Real Time Hourly (RT-H), stochastic
- Daily Real Time 5 minute (RT-5), stochastic

Each simulation provides insights into the system operation and helps guide the selection of time periods for the following steps. At each step of the process the system was examined for the following operational issues:

- Overgeneration, or dump energy
- Regulation down violations (regdn)
- Regulation up violations (regup)
- Spinning Reserve violations
- Non-spinning Reserve violations

In the results presented in Section 5 of the report, overgeneration and regulation down violations are combined together (and called overgeneration) since they both represent conditions where instantaneous generation is more than load.

C.2 Stochastic Simulation

The day-ahead (DA) hourly, stochastic simulation was performed first. This simulation showed that most of the over generation occurred in May and the surrounding months Figure C-1 shows the monthly over generation from the initial deterministic case (imports 100% firm) and the Day Ahead stochastic simulation. There were no significant other violations (regulation up and spin) in these simulations. Therefore, subsequent simulations focused on four months - April, May, June and July.

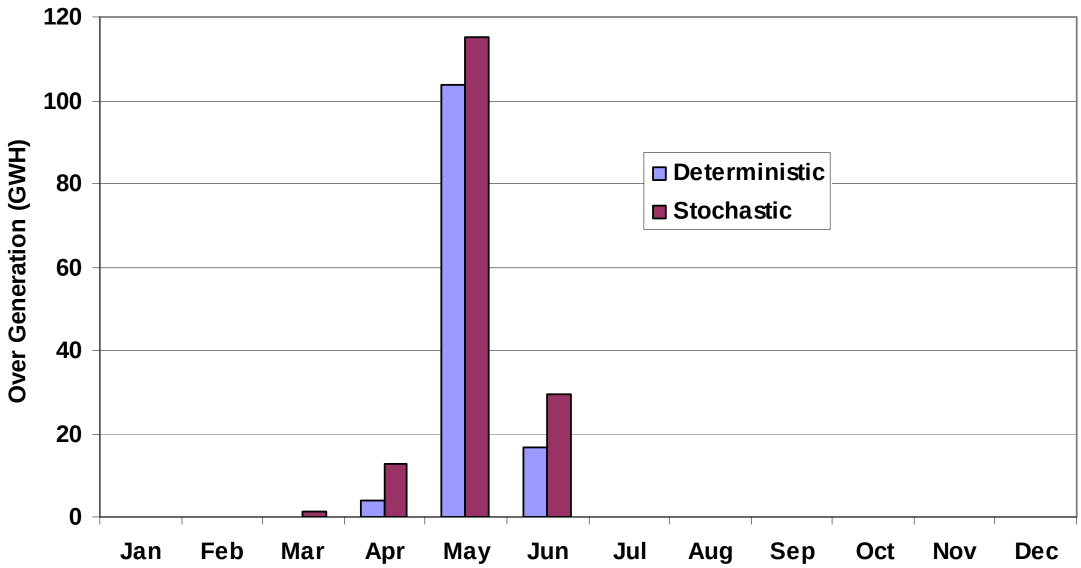


Figure C-1: Monthly over generation

With the unit commitment of long-start units from the DA simulation frozen, the hour-ahead, stochastic (hourly) simulations were performed for the four months. Both the day-ahead and hour-ahead simulations commit and dispatch to the forecasted load for 100 draws of the load forecast. Also, the wind generation in the commitment and dispatch are the same in each one the 100 iterations. Therefore, there is no uncertainty in load and wind generation in the day-ahead and hour-ahead stochastic simulations. The end-result of the day-ahead and hour-ahead stochastic simulation is a set of unit commitment for long and medium-start generators for the 100 iterations.

In order to evaluate the impact of uncertainty in load and wind generation forecasts, the unit commitment obtained from the HA market simulation (for each one of the 100 forecasts) was used to dispatch the system with actual hourly loads and hourly actual wind generation. In this real-time, hourly simulation (RT-H) simulation, only quick starts were allowed to be committed in addition to the long and medium-start units. Figure C-2 shows the monthly over generation results for the selected months, including the RT-H simulations. The month of May accounts for 80% of the annual over generation in the RT-H simulation. Figure C-3 shows the operating issues from each day from the DA, HA and RT-H simulations for the month of May. The over generation plus regulation down shortages for the RT-H simulations are shown in the last column. It should be reiterated that the over generation and regulation down violations in this simulation are due to the uncertainty in load and wind generation forecasts as modeled in the stochastic process. The RT-H simulation does not capture the impact of variability in load and wind generation since these simulations are done at an hourly time scale. The real-time, 5-minute simulations are used to capture the operational impacts of variability. This is discussed next.

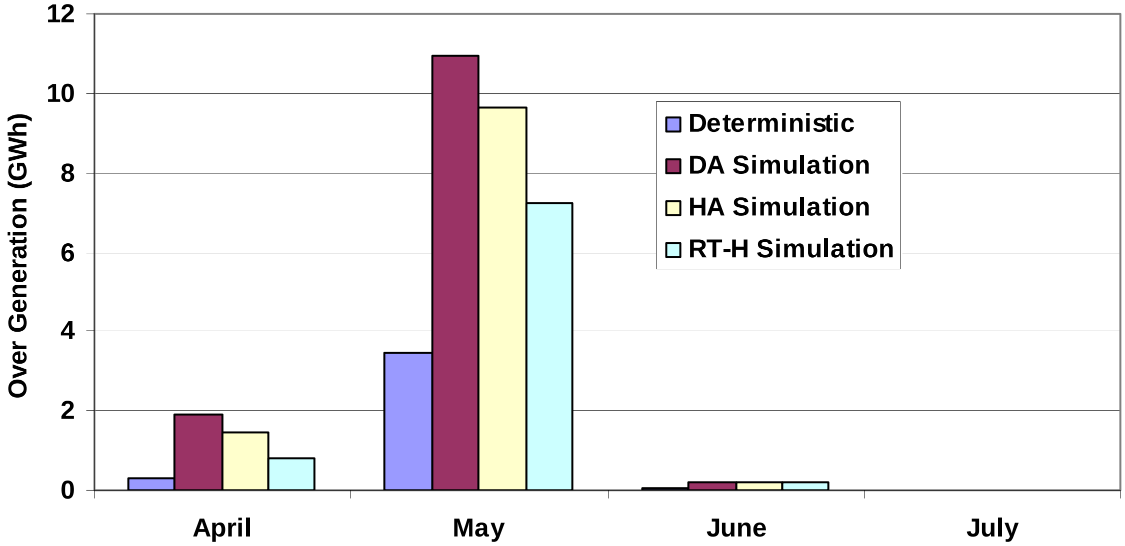


Figure C-2: Monthly over generation, imports 50% firm

From the RT-H simulations, it was decided to examine May 28th for the impact of variability in load and wind generation. Table C-1 shows the over generation results of the 5-minute (RT-5) simulation as well as the RT-H simulation. The overgeneration is higher in the RT-5 simulation since it includes the impact of uncertainty, as well as variability. The ratio of over generation in the RT-5 and RT-H simulation for May 28th is 2.2. While the RT-H identified days when uncertainty in load and wind generation is likely to result in operational problems, other methods were used to identify interesting days when the intra-hour ramps might exacerbate these problems. The next section discusses this methodology.

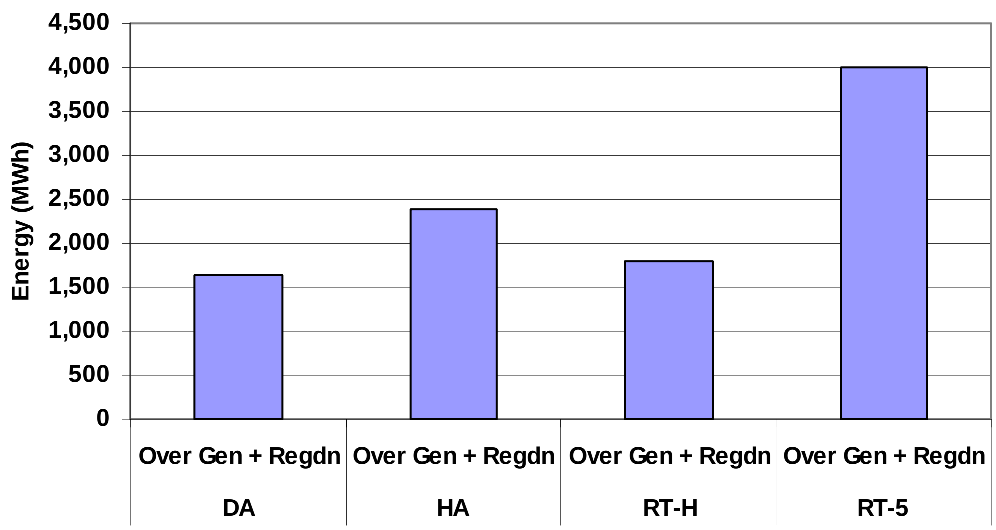


Figure C-3: Over generation for May 28th in RT-H and RT-5 Simulations.

Table C-1: Daily operating issues for May.

	DA	HA	RT-H	DA	HA	RT-H	DA	HA	RT-H
Date	Over Gen	Over Gen	Over Gen	Regdn	Regdn	Regdn	Over Gen + Regdn	Over Gen + Regdn	Over Gen + Regdn
5/1/2012	0.0	0.0	0.0	0.5	0.0	0.0	0.5	0.0	0.0
5/2/2012	1.0	0.0	0.0	1.7	1.9	0.0	2.7	1.9	0.0
5/3/2012	0.0	5.0	0.0	1.8	6.2	0.0	1.8	11.2	0.0
5/4/2012	67.8	86.5	15.2	73.2	110.7	48.4	141.0	197.2	63.7
5/5/2012	85.8	62.3	10.1	58.2	71.4	45.7	144.0	133.6	55.8
5/6/2012	5.9	2.5	1.0	18.7	11.2	8.7	24.6	13.7	9.7
5/7/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.3	0.0
5/9/2012	167.4	292.3	247.8	92.2	110.0	132.6	259.6	402.4	380.4
5/10/2012	41.6	106.9	54.0	12.6	23.3	15.2	54.2	130.2	69.2
5/11/2012	1.2	78.6	11.4	3.8	24.1	8.0	5.0	102.8	19.4
5/12/2012	6.1	4.4	0.0	5.3	3.2	0.0	11.5	7.7	0.0
5/13/2012	18.0	10.8	0.8	6.5	5.3	0.1	24.5	16.1	0.9
5/14/2012	4.3	13.3	4.4	2.2	3.6	1.5	6.5	16.9	5.9
5/15/2012	43.8	101.4	9.8	0.0	0.0	0.0	43.8	101.4	9.8
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	2.6	12.8	0.0
5/17/2012	7.8	3.6	0.0	0.0	0.0	0.0	7.8	3.6	0.0
5/18/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0	6.7	0.0	0.0	33.3	25.7	3.0
5/20/2012	241.6	356.5	93.5	152.9	201.7	164.4	394.4	558.2	257.9
5/21/2012	349.6	269.5	121.5	1.2	1.1	0.0	350.9	270.7	121.5
5/22/2012	348.2	364.4	257.8	0.0	0.0	0.0	348.2	364.4	257.8
5/23/2012	19.5	136.1	42.7	0.0	0.0	0.0	19.5	136.1	42.7
5/24/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/25/2012	0.0	6.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0
5/26/2012	19.2	27.7	1.9	36.7	53.1	31.6	56.0	80.9	33.6
5/27/2012	1,058.1	802.9	331.5	347.7	375.3	330.5	1,405.9	1,178.2	662.0
5/28/2012	1,140.7	1,622.0	780.3	489.8	756.9	1,021.6	1,630.5	2,378.9	1,801.9
5/29/2012	166.4	203.8	133.1	0.0	0.0	0.0	166.4	203.8	133.1
5/30/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0
Total	3,823.8	4,595.2	2,119.8	1,311.9	1,759.4	1,808.4	5,135.7	6,354.6	3,928.1

C.3 Further Analysis for Interesting Days

A combination of statistical data analysis, generation schedules, and results from Plexos deterministic and stochastic simulations was used to find "interesting" periods during the year for more extensive analysis. These periods included

- Days when real-time net load ramp up and down events far exceeded the average hourly scheduled (forecasted) ramp
- Days when real-time net load ramp up and down events are a high percentage of the hourly flexible generation
- Days with low amounts of dispatchable generation
- Days with Dump Energy in the stochastic hourly simulations
- Days with regulation and spin shortfalls in the hourly stochastic simulation

A number of days meeting each criterion above were selected on their merits, then they were collectively ranked and prioritized to determine a subset of days for in-depth analysis.

C.4 Five-Minute Ramp Ratios

The five-minute load, wind, solar and net load ramps were analyzed to find periods during the year when maximum five-minute net load ramp in an hour was much greater than the average scheduled ramp during the hour. The general procedure was

1. create 5-minute deltas (difference between successive 5-minute periods)
2. calculate maximum positive delta and maximum negative delta in each hour
3. calculate the average delta in each hour
4. compute ratio maximum delta/average delta for each hour

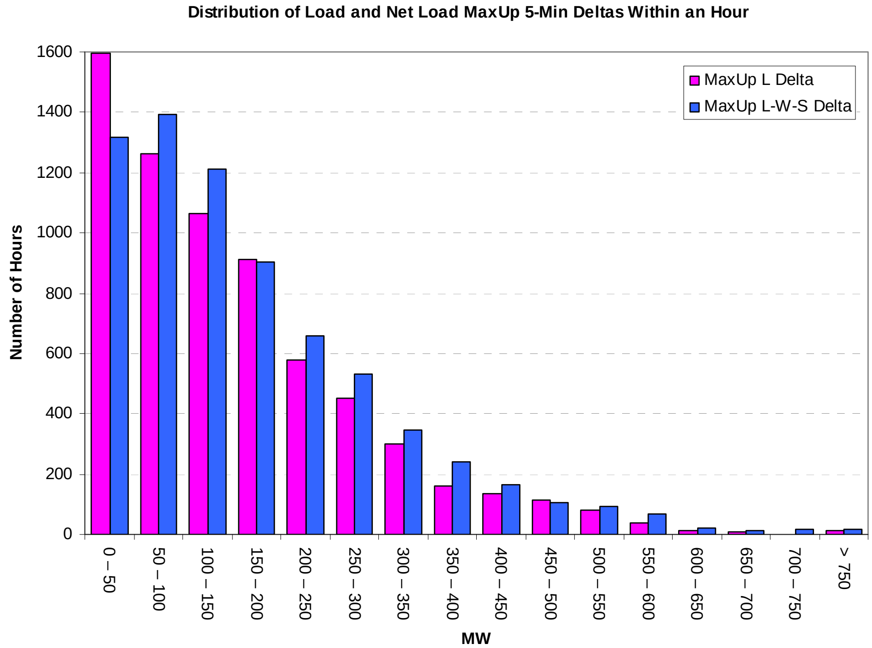
The concern is that the commitment is based on the hourly loads and therefore only consider the hourly load deltas and by extension, only the average 5-minute deltas within the hour. If a particular 5-minute delta is 10 or 20 times the average for the hour then there might not be enough ramping capability available and ramp violations could occur.

C.4.1 Load and Net Load Deltas

Figure C-4 shows the distribution of load and net load maximum 5-minute deltas in each hour of the 2006 shape year. The magenta bars show the number of positive and negative load deltas in each bin, and the blue bars show the number of positive and negative net load deltas in each bin. Net Load is defined as Load – Wind – Solar generation. As expected, each half of the distribution of deltas is skewed, but more so for load than net load.

For the positive deltas (or up-ramps), 80% of the load deltas are in the first 4 bins (200 MW or less) whereas only 68% of the net load deltas are 200 MW or less. On the tails of the distribution, there are 35 hours with a five-minute load delta of 600 MW or more, and 68 hours with a net load delta of 600 MW. However, the largest load up-ramp, 5,637 MW, is about the same as the largest net load up-ramp 5,634 MW.

The difference between load and net load is less distinct for the down-ramps. Approximately 77% of load deltas are 200 MW or less, and about 74% of net load deltas are in the same range. On the tail end, 11 load down-ramps are greater than or equal to 600 MW, compared to 19 net load down-ramps. Again, the largest load down-ramp, 5,808 MW, is about the same as the largest net load down-ramp.



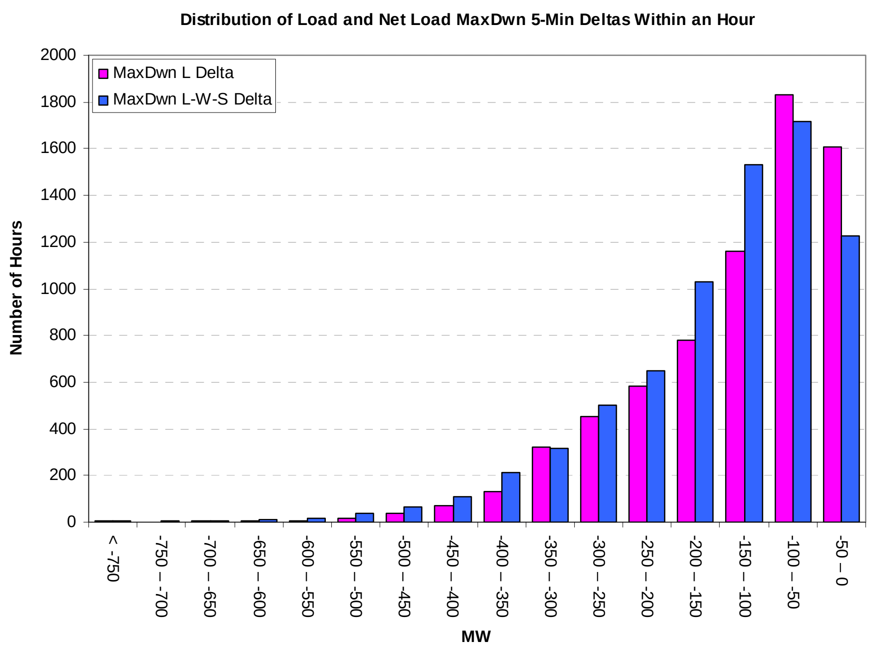


Figure C-4: Distribution of maximum 5-minute load and net load deltas in each hour

These 5-minute deltas are compared to the average 5-minute deltas within the hour to identify periods where the real-time ramping requirement outpaces the scheduled hourly ramp. Figure C-5 shows the distribution of average 5-minute ramps for load and net load in the 2006 shape year. The top plot shows the distribution of positive load and net load average 5-minute deltas, and the bottom plot shows the distribution of negative load and net load average 5-minute deltas. On both plots there are more hours with large average

5-minute deltas (on the tails of the distributions) with wind and solar than with load alone, although the difference may not be as great as expected.

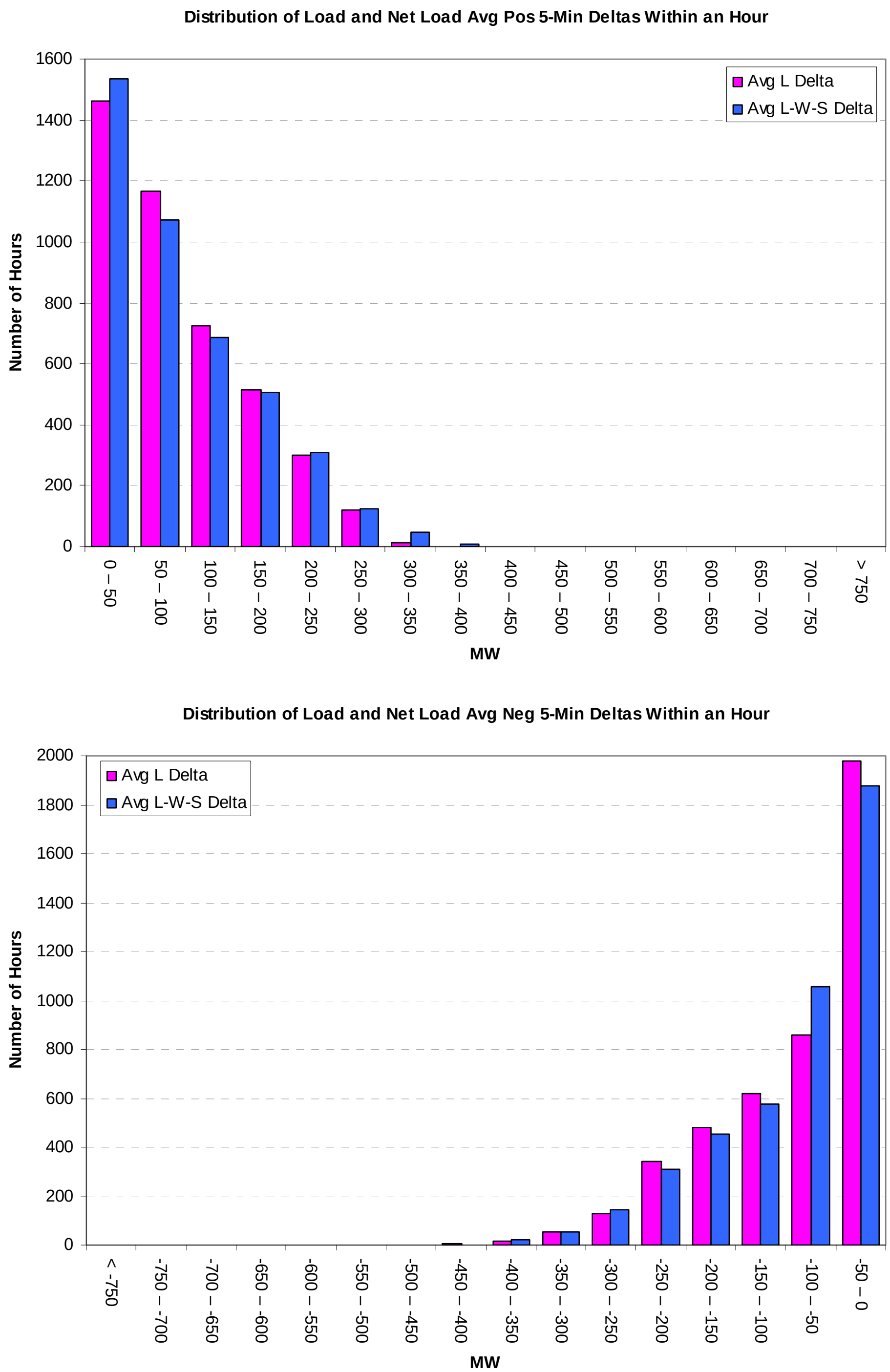


Figure C-5: Distribution of average hourly load and net load deltas

C.4.2 Max/Average Ratios

The maximum five-minute deltas and average five-minute deltas discussed above were used to compute the ratios. The simple relation is:

$$\text{Ratio} = \frac{\text{Maximum Five-Minute Ramp}}{\text{Average Five-Minute Ramp}}$$

Large ratios that are due to a small average hourly ramp (in the numerator) are not particularly interesting. Therefore a threshold was used to screen out these hours. Figure C-6 below (a scatter plot of maximum positive deltas versus average hourly deltas) shows how this threshold was determined. In the figure, magenta triangles represent a load hours and blue diamonds represent net load hours.

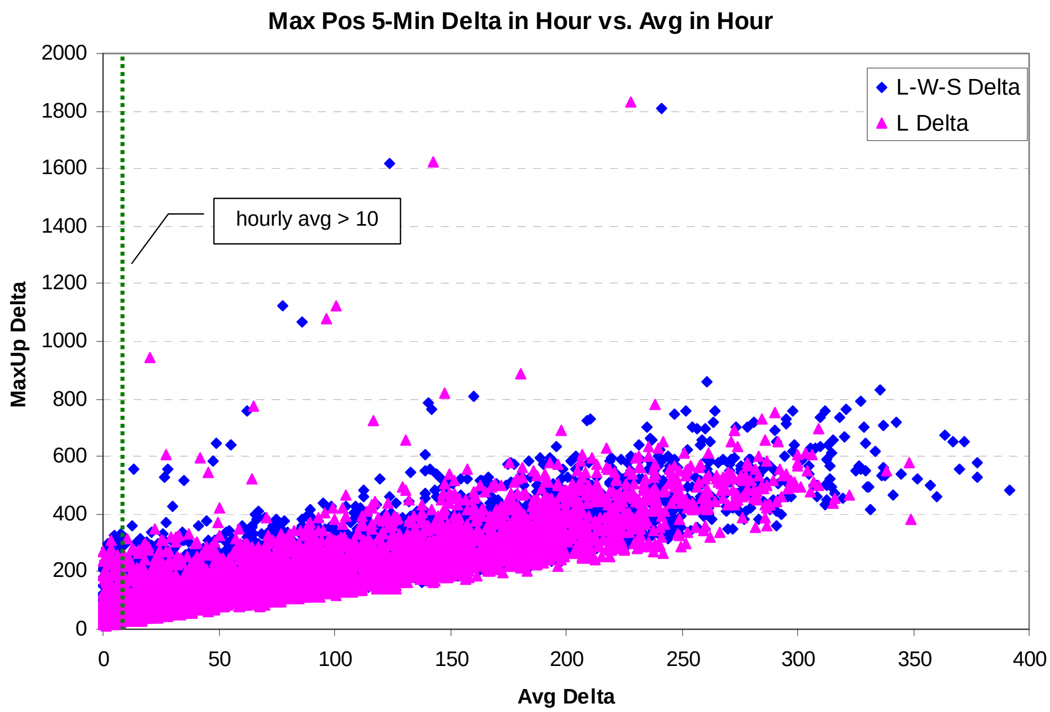


Figure C-6: Scatter plot of maximum positive deltas versus average delta in each hour

All the hours with a large maximum five-minute delta fall to the right of the vertical line at Avg Delta = 10. Therefore an initial threshold of Avg Delta > 10 was used to screen out large ratios caused by small averages. A similar threshold was used to initially screen the down-ramp ratios. Subsequently, an exercise was carried to determine if the initial threshold should be increased from 10, i.e. whether a threshold of 20 or 30 would be more selective.

Figure 7 shows the MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30 over the year. Blue diamonds represent ratios where Avg Delta >10, magenta squares represent ratios where Avg Delta >20, and green triangles represent ratios where Avg Delta > 30. The superposition of ratios selected using these three screening values confirm that there is no advantage in filtering with a threshold greater than 10.

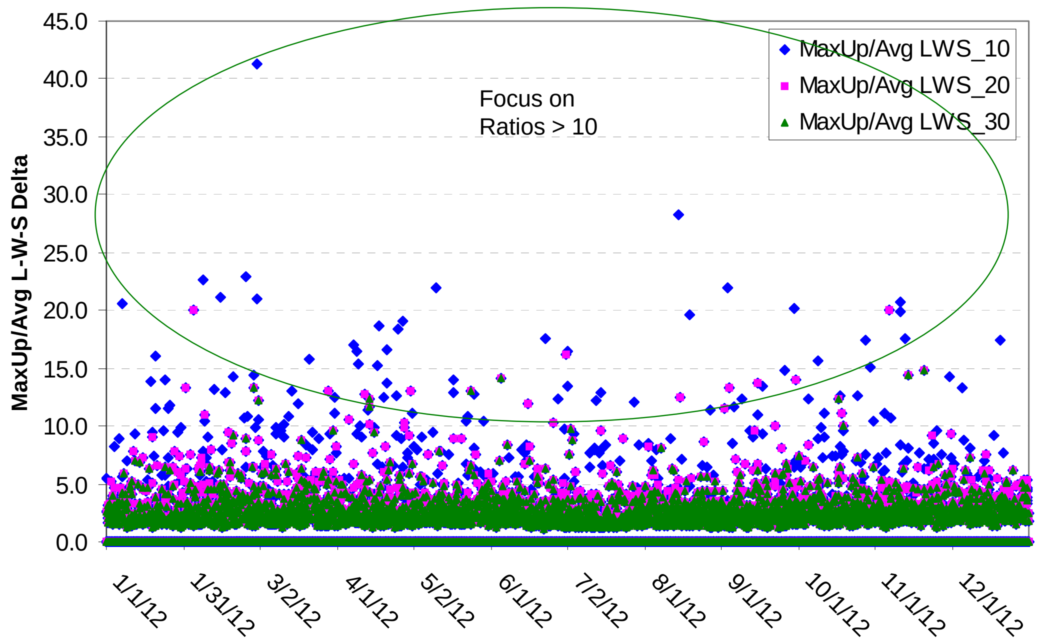


Figure C-7: MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30

Figure C-8 shows a scatter plot of the up-ramp ratios versus the average hourly delta. As before, magenta triangles represent a load hours and blue diamonds represent net load hours. As expected, there are many large ratios clustered vertically on the left side where the average hourly delta is low.

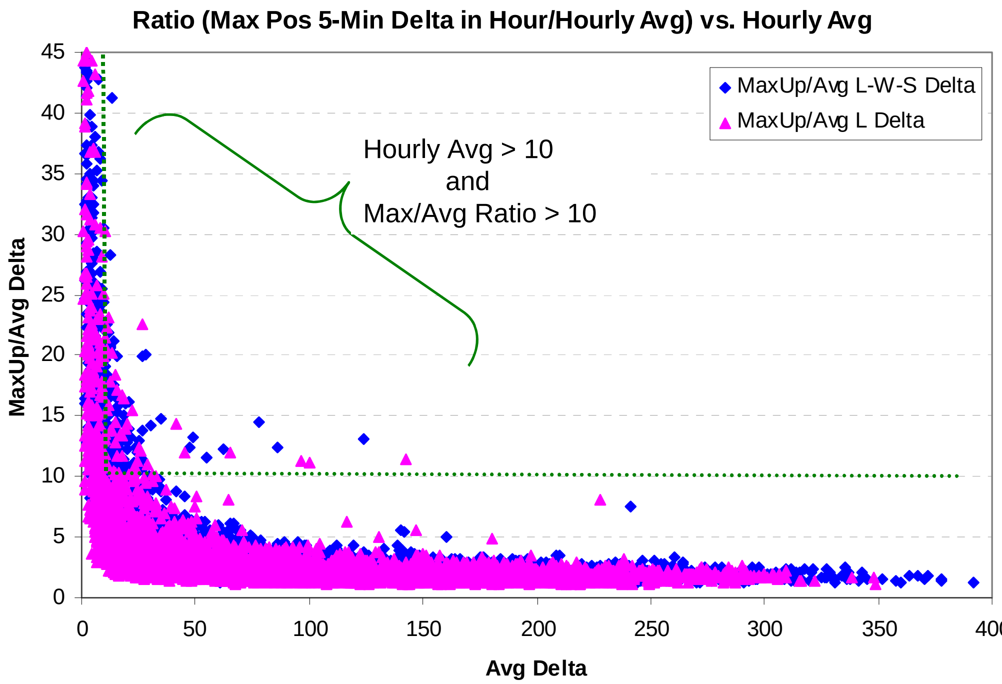


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Figure C-8: Scatter plot of MaxUp/Avg ratio versus average delta in each hour

However, the largest ratio with Avg Delta > 10 is at 41.2. In general, the set of hours with Max/Avg ratio > 10 and Avg Delta >10, (i.e. to the left of the vertical green line and above the horizontal green line) are the hours of interest from this exercise. These hours are listed in Table C-2. The hours of interest for down-ramps were determined in a similar manner and are listed in Table C-3.

Table C-2: Periods of Interest Based on MaxUp/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
2/29/12 15:00	41.2	10/28/12 2:00	17.4	5/17/12 14:00	14.0	4/12/12 7:00	12.8	9/5/12 18:00	11.6	5/29/12 18:00	10.5
8/14/12 19:00	28.3	12/20/12 8:00	17.4	1/24/12 8:00	14.0	5/26/12 4:00	12.8	1/20/12 10:00	11.5	2/8/12 18:00	10.5
2/25/12 8:00	22.9	4/8/12 7:00	17.0	9/30/12 18:00	13.9	10/18/12 7:00	12.6	9/2/12 5:00	11.5	10/31/12 13:00	10.4
2/8/12 2:00	22.6	4/21/12 2:00	16.5	1/18/12 8:00	13.9	10/25/12 2:00	12.6	1/25/12 8:00	11.5	5/22/12 17:00	10.4
5/10/12 19:00	21.9	4/9/12 7:00	16.5	9/15/12 3:00	13.8	4/25/12 9:00	12.6	4/13/12 16:00	11.4	6/26/12 2:00	10.4
9/3/12 5:00	21.9	7/2/12 2:00	16.5	4/21/12 1:00	13.7	3/31/12 7:00	12.5	8/27/12 18:00	11.4	4/28/12 7:00	10.3
2/15/12 2:00	21.1	7/1/12 3:00	16.2	9/17/12 13:00	13.5	4/20/12 3:00	12.5	10/19/12 1:00	11.2	4/14/12 5:00	10.2
3/1/12 1:00	21.0	1/20/12 8:00	16.1	7/1/12 19:00	13.4	8/15/12 19:00	12.4	11/4/12 14:00	11.1	3/11/12 3:00	10.1
11/11/12 4:00	20.7	3/21/12 7:00	15.7	12/5/12 8:00	13.4	4/14/12 8:00	12.4	10/11/12 16:00	11.1	10/19/12 6:00	10.1
1/7/12 3:00	20.6	10/9/12 12:00	15.6	2/1/12 13:00	13.4	10/5/12 16:00	12.4	5/1/12 11:00	11.1	9/22/12 7:00	10.0
9/29/12 18:00	20.2	4/9/12 16:00	15.3	9/4/12 2:00	13.3	10/17/12 10:00	12.4	3/31/12 10:00	11.1	4/10/12 9:00	10.0
2/4/12 18:00	20.1	4/17/12 7:00	15.2	2/28/12 8:00	13.2	9/9/12 7:00	12.3	9/15/12 11:00	11.0		
11/6/12 12:00	20.0	10/30/12 2:00	15.1	2/12/12 13:00	13.2	6/28/12 2:00	12.3	2/9/12 2:00	10.9		
11/11/12 3:00	19.9	9/26/12 7:00	14.9	5/24/12 11:00	13.1	3/1/12 8:00	12.2	5/23/12 14:00	10.9		
8/19/12 5:00	19.6	11/20/12 10:00	14.8	4/30/12 19:00	13.1	7/13/12 2:00	12.2	3/13/12 8:00	10.8		
4/27/12 19:00	19.1	2/28/12 7:00	14.5	3/14/12 16:00	13.0	7/28/12 4:00	12.0	2/26/12 6:00	10.8		
4/18/12 10:00	18.7	11/14/12 7:00	14.4	3/29/12 2:00	13.0	3/17/12 7:00	12.0	2/24/12 16:00	10.7		
4/25/12 16:00	18.4	11/30/12 15:00	14.3	5/17/12 18:00	12.9	6/16/12 3:00	12.0	11/7/12 12:00	10.7		
11/13/12 3:00	17.6	2/20/12 8:00	14.3	2/17/12 2:00	12.9	1/26/12 10:00	11.7	3/1/12 9:00	10.6		
6/23/12 4:00	17.5	6/5/12 12:00	14.2	7/15/12 3:00	12.9	4/14/12 9:00	11.6	4/6/12 7:00	10.6		

Table C-3: Periods of Interest Based on MaxDown/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
10/27/12 0:00	69.5	8/6/12 18:00	15.1	10/30/12 15:00	11.9	4/4/12 15:00	10.4
5/3/12 17:00	30.6	5/24/12 10:00	14.8	7/30/12 18:00	11.9	12/9/12 3:00	10.4
5/7/12 10:00	24.4	10/11/12 10:00	14.7	2/7/12 14:00	11.7	2/7/12 12:00	10.3
5/2/12 11:00	19.3	1/23/12 14:00	14.7	5/26/12 0:00	11.7	10/13/12 10:00	10.3
1/12/12 12:00	19.2	1/4/12 11:00	14.4	1/3/12 12:00	11.7	11/9/12 3:00	10.3
12/2/12 6:00	18.2	2/3/12 10:00	14.1	5/9/12 14:00	11.6	6/2/12 18:00	10.3
7/25/12 19:00	18.1	5/2/12 10:00	14.0	7/2/12 14:00	11.3	2/26/12 19:00	10.3
3/16/12 3:00	17.9	3/25/12 14:00	13.8	3/1/12 15:00	11.0	11/15/12 15:00	10.3
3/24/12 15:00	17.3	1/22/12 6:00	13.8	8/31/12 14:00	11.0	3/7/12 9:00	10.2
10/22/12 2:00	17.0	1/4/12 18:00	13.6	4/6/12 1:00	10.8	12/17/12 15:00	10.2
4/15/12 5:00	16.9	2/26/12 8:00	13.2	6/30/12 4:00	10.8	7/14/12 15:00	10.2
3/11/12 4:00	16.8	6/18/12 14:00	13.2	9/13/12 11:00	10.7	4/26/12 19:00	10.2
7/17/12 2:00	16.7	3/11/12 6:00	13.2	10/25/12 11:00	10.7	5/19/12 14:00	10.1
10/28/12 6:00	16.6	11/14/12 12:00	13.1	8/10/12 19:00	10.6	4/8/12 0:00	10.1
7/25/12 14:00	16.4	12/11/12 14:00	12.4	1/20/12 15:00	10.6	2/24/12 8:00	10.1
5/13/12 16:00	16.0	11/20/12 18:00	12.3	5/20/12 4:00	10.6	9/21/12 16:00	10.0
4/25/12 19:00	15.5	5/1/12 14:00	12.2	11/9/12 12:00	10.6		
5/2/12 16:00	15.4	8/26/12 4:00	12.1	4/2/12 16:00	10.6		
4/24/12 16:00	15.3	12/11/12 15:00	12.0	10/3/12 18:00	10.5		
4/24/12 19:00	15.3	7/6/12 2:00	11.9	10/7/12 15:00	10.4		

C.5 Flexible generation Ratios

The other aspect that was considered was the amount of dispatchable generation available within the hour. An hour with a relatively small ramp but with little dispatchable generation may cause more difficulty that an hour with large ramps and lots of dispatchable generation. The analysis started with the 2012 deterministic dispatch for the year based on the 2006 load profile. 50% of the imports were assumed to be fixed and the remainder dispatchable at $80/MWh. All of the Geothermal, Biomass, Nuclear, Qualifying Facilities (QF), Wind and Solar generation were assumed to be firm. Only the in-state gas fired generation was left dispatchable. Figure C-9 shows the results for the first week in May. Although the loads ranged from roughly 20,000 MW to 35,000 MW the amount of dispatchable generation, which is the difference between the load and total non-dispatchable generation, was very low at times.

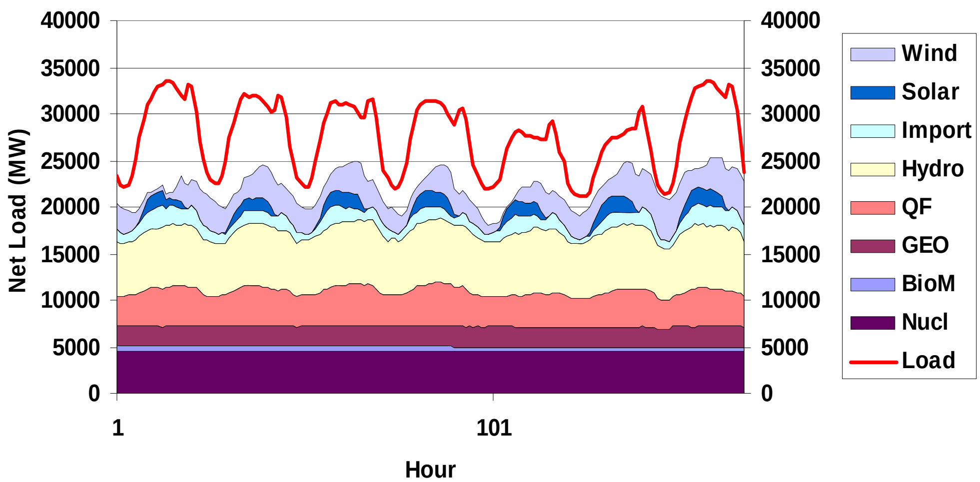

Figure C-9: Dispatch for the first week of May.

The analysis then examined each hour for "interesting" events. In addition to the hours identified previously when the maximum up and down ramps were greater than ten times the average ramp the amount of dispatchable generation was also considered. First, hours with less than 1500 MW of dispatchable generation were flagged. Then the maximum ramps were compared to the amount of dispatchable generation. Those hours when the maximum up or down 5-minute ramp exceed 15% of the dispatchable generation were identified. Table C-4 lists all of the events for the month of May. All of the evaluation criteria is shown with the items flagged highlighted in yellow. In some hours and days multiple events occurred.

Table C-4: Interesting events for May

Month	Day	Hour	MaxUp L-W-S Delta	MaxDwn L-W-S Delta	Dispatchable	Max Up / Disp	Max Dn / Disp	MaxUp/Avg LWS_10	MaxDwn/Avg LWS_10	Events
5	1	12	157.3	-89.1	10,610.9	1%	-1%	11.1		1
5	1	15	60.2	-138.4	11,494.0	1%	-1%		12.2	1
5	2	11	69.2	-213.9	9,958.6	1%	-2%		14.0	1
5	2	12	46.0	-201.9	10,135.3	0%	-2%		19.3	1
5	2	17	74.5	-204.1	8,970.0	1%	-2%		15.4	1
5	3	18	174.1	-390.3	6,207.1	3%	-6%		30.6	1
5	4	5	328.1	-17.6	2,072.8	16%	-1%	2.2		1
5	7	11	81.1	-251.2	9,680.0	1%	-3%		24.4	1
5	9	3	84.1	-72.7	1,087.3	8%	-7%			1
5	9	4	206.5	-29.3	920.0	22%	-3%	2.1		2
5	9	5	247.8	-4.3	1,441.3	17%	0%	2.0		2
5	9	6	397.6	116.5	2,572.0	15%	0%	1.9		1
5	9	15	113.8	-128.2	9,869.1	1%	-1%		11.6	1
5	10	20	253.6	-193.1	8,544.9	3%	-2%	21.9		1
5	13	17	61.6	-230.7	9,432.7	1%	-2%		16.0	1
5	17	15	141.5	-207.2	11,964.8	1%	-2%	14.0		1
5	17	19	206.4	-145.6	11,001.9	2%	-1%	12.9		1
5	19	15	60.2	-132.4	5,849.4	1%	-2%		10.1	1
5	20	4	33.4	-75.1	1,389.5	2%	-5%		3.4	1
5	20	5	95.3	-142.4	1,268.0	8%	-11%		10.6	2
5	20	7	160.7	-33.3	903.0	18%	-4%	2.7		2
5	20	8	222.6	105.1	1,021.0	22%	0%	1.5		2
5	21	2	23.9	-66.1	1,241.0	2%	-5%		3.2	1
5	21	3	21.0	-27.6	1,084.0	2%	-3%			1
5	21	4	123.5	47.1	998.7	12%	0%	1.4		1
5	21	5	225.0	-121.1	1,328.2	17%	-9%	1.9		2
5	22	2	-11.6	-104.4	883.7	0%	-12%		2.6	1
5	22	3	56.7	-61.1	691.0	8%	-9%			1
5	22	4	127.7	45.9	928.1	14%	0%	1.5		1
5	22	5	273.1	3.1	1,165.0	23%	0%	2.1		2
5	22	6	340.7	115.3	2,293.8	15%	0%	1.7		1
5	22	18	164.3	-238.1	6,125.0	3%	-4%	10.4		1
5	23	15	133.4	-78.8	9,952.5	1%	-1%	10.9		1
5	24	11	58.4	-1,231.4	9,590.6	1%	-13%		14.8	1
5	24	12	1,618.8	-449.5	9,919.5	16%	-5%	13.1		2
5	26	1	198.1	-171.1	3,111.4	6%	-6%		11.7	1
5	26	5	168.8	-125.6	2,492.5	7%	-5%	12.8		1
5	27	2	3.6	-77.8	1,277.9	0%	-6%		2.1	1
5	27	3	36.3	-45.3	1,143.1	3%	-4%			1
5	27	4	107.4	-11.2	948.2	11%	-1%	5.1		1
5	27	5	105.6	-127.3	1,050.6	10%	-12%			1
5	27	6	168.7	2.2	1,399.1	12%	0%	3.6		1
5	27	7	202.4	-159.6	895.5	23%	-18%	3.6		3
5	27	8	293.8	-181.4	969.1	30%	-19%	3.3		3
5	27	9	310.3	39.2	1,263.9	25%	0%	2.4		2
5	28	2	-12.9	-76.6	1,397.0	0%	-5%		1.8	1
5	28	3	17.6	-34.3	1,123.5	2%	-3%			1
5	28	4	65.7	1.6	1,165.2	6%	0%	2.6		1
5	28	5	135.6	-126.7	1,324.0	10%	-10%			1
5	28	6	128.9	-1.7	1,450.5	9%	0%	3.3		1
5	28	7	129.3	-9.7	914.7	14%	-1%	1.8		1
5	28	8	214.0	-199.4	692.1	31%	-29%	4.0		3
5	28	9	221.0	71.2	774.2	29%	0%	1.6		2
5	28	10	123.3	4.3	1,061.6	12%	0%	1.7		1
5	28	15	47.7	-126.2	1,414.4	3%	-9%			1
5	28	16	69.7	-28.3	1,205.6	6%	-2%	3.1		1
5	29	1	61.0	-93.8	1,340.3	5%	-7%		2.5	1
5	29	2	73.0	-104.4	1,269.5	6%	-8%		6.9	1
5	29	19	184.8	-58.9	8,122.9	2%	-1%	10.5		1

Figure C-10 shows the total number of interesting events by month. This analysis, along with the previous hourly stochastic dispatch analysis for the year, confirmed that the month of May would be the most difficult from an operational standpoint. Another summary of the statistics is shown in Table C-5.

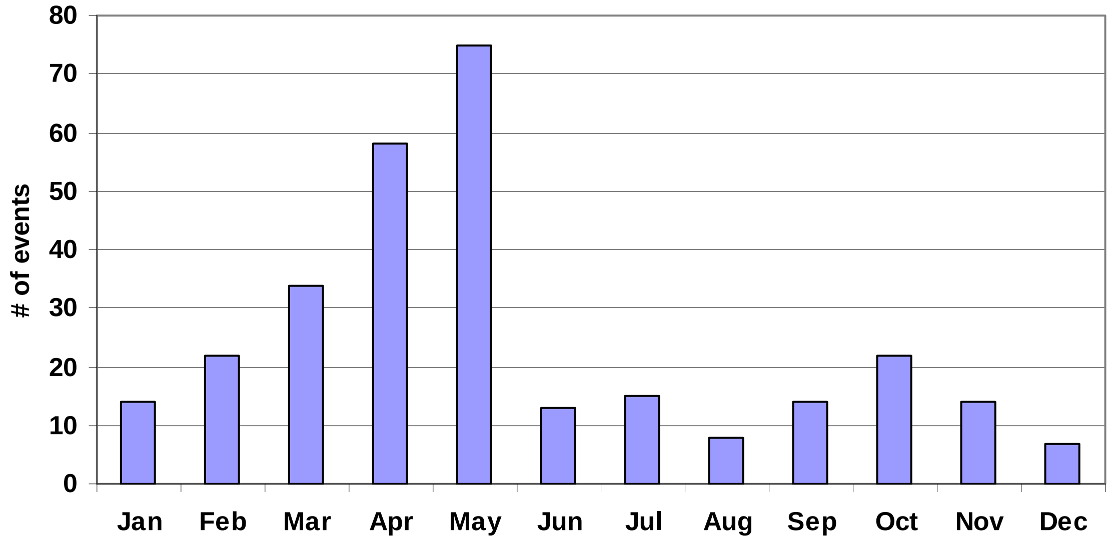

Figure C-10: Number of "interesting" event by month

Table C-5: Statistics of interesting events, 2006

Event	Count
1) Dispatchable Generation < 1500 MW	61
2) Max Up / Dispatchable > 15%	37
3) Max Down / Dispatchable > 15%	11
4) Max Up Ramp / Avg Ramp > 10	111
5) Max Down Ramp / Avg Ramp > 10	76
total events	296
Unique hours	263
Unique days	152
Days > 2 events	28

Table C-6 shows the days with more than two events happening at some time within the day. From this analysis, and based on statistics from the hourly stochastic dispatches, the days of May 16, 17, 24, 27 and 28 were selected for further sub-hourly analysis.

Table C-6: Summary of days with more than two events.

Month	Day	Events
1	20	3
2	26	3
3	1	4
3	11	3
3	25	12
3	26	4
4	6	4
4	8	3
4	9	3
4	14	7
4	15	10
4	17	4
4	19	3
4	21	5
4	25	3
4	27	3
5	2	3
5	9	7
5	20	7
5	21	5
5	22	7
5	24	3
5	27	13
5	28	14
5	29	3
6	11	3
7	2	4
10	27	3

C.6 2007 Analysis

The bulk of the analysis was performed on the 2006 load and generation shape data which had a high amount of hydro generation. The year 2007, which had significantly less hydro generation, was also analyzed. Figure C-11 shows a comparison of the generation by type for the two shape years considered. The hydro generation in 2007 is only slightly more than half of the 2006 level. The bulk of the difference is made up by increased imports and in-state gas fired generation.

Figure C-11: Comparison of generation by type for 2006 and 2007

Table C-7 Compares the amount of firm generation available each hour for the 2006 and 2007 based simulations. Because of the reduced hydro generation there is more flexible generation available to operate each hour.

Table C-7: Comparison of generation by type for 2006 and 2007

Gentyp	2006, Imports 50% Firm	2007, Imports 50% Firm
BioM	4,692	4,692
Gas	77,486	83,677
GEO	19,019	19,017
Hydro	37,240	20,662
Import	20,858	26,638
Nucl	39,967	39,967
Oil	1,010	1,010
Other	226	227
Solar	4,907	4,907
Wind	17,886	17,886
QF	39,206	42,129
Shydro	1,047	1,047
Total	263,543	261,858
Renewable	47,550	47,547
Renewable	18%	18%

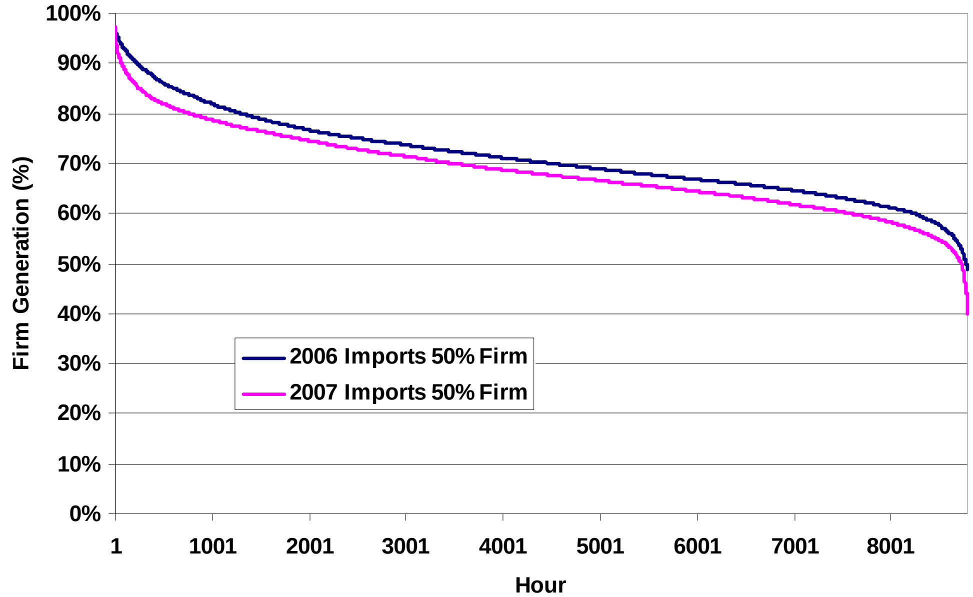

Figure C-12: Comparison of firm generation for 2006 and 2007

The operating issues (high ramping, low flexibility, etc) were also evaluated for the 2007 shapes. Figure C-13 shows the number of issues occurring each month. Similar to what was seen in the 2006 analysis, May seemed to be the worst month. Figure C-13 shows the number and type of issues for each day in May. Based on these results May 22nd and 23rd were studied at the 5-minute level.

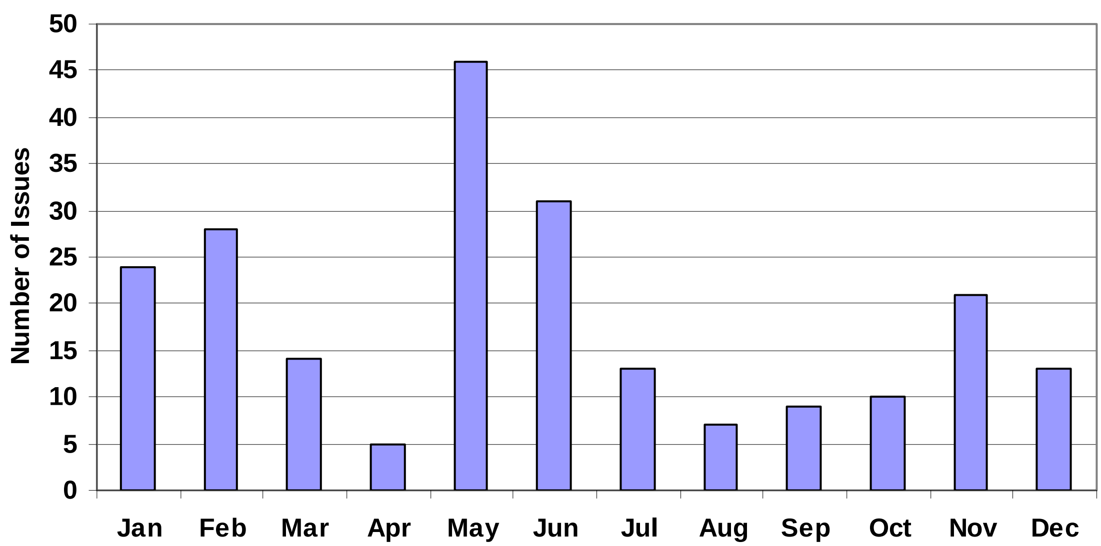

Figure C-13: Number of Operating issues in 2007

Table C-8: Daily Operating Issues in May 2007

Month	Day	Sum of Events	Max of MaxUp/Avg LW_10	Min of MaxDwn/ Avg LW_10	Max of Max Up L-W / Flexible Gen	Min of Max Dn L-W / Flexible Gen	Min of % Dispatchable Gen
5	1	1		10.9	1%	-4%	28%
5	3	2		10.6	3%	-3%	22%
5	4	1		17.1	2%	-3%	23%
5	8	3	5.9	1.6	2%	-5%	8%
5	9	1		23.4	3%	1%	28%
5	12	1		10.8	7%	-3%	25%
5	15	5	21.2	1.5	14%	-7%	9%
5	16	1	16.4		0%	-1%	28%
5	18	1		10.3	7%	1%	21%
5	19	1		11.8	7%	0%	21%
5	21	1		11.2	1%	-2%	19%
5	22	17	4.5	1.9	23%	-11%	6%
5	23	7	4.0	2.4	16%	-14%	7%
5	25	1		10.3	4%	-2%	20%
5	27	2		19.1	5%	0%	28%
5	31	1	10.0		1%	-1%	29%

C.7 Analysis of Operational capability under 20% RPS – Additional results

Sub-hourly analysis was conducted for five separate days within the month of May. Those days were the 16th, 17th, 24th, 27th and 28th. In addition to the 5-minute analysis a 10-minute analysis was done for the 24th and 28th for comparison purposes. Table C-9 shows the results from the DA, HA and RT-H analysis for comparison. The overall conclusion appears to be that if the hourly level simulations say that there is no operational issues, or only relatively small issues, then the sub-hourly analysis shows that the issues tend to go away. However, if the hourly level indicates that there may be a more significant issue then the sub-hourly simulation shows an even larger impact. Figures C-14 through Figure C-18 show the results graphically for the individual days where sub-hourly analysis was performed. Figure C-19 and Figure C-20 show similar results for May 22nd and 23rd from the 2007 analysis.

Table C-9: Comparative operational results for May

	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5
Date	Dump	Dump	Dump	Dump	Regdn	Regdn	Regdn	Regdn	Regup	Regup	Regup	Regup	Spin	Spin	Spin	Spin	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn
5/1/2012	0.0	0.0	0.0		0.5	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.5	0.0	0.0	0.0
5/2/2012	1.0	0.0	0.0		1.7	1.9	0.0		0.0	0.0	0.0		0.0	0.0	0.0		2.7	1.9	0.0	0.0
5/3/2012	0.0	5.0	0.0		1.8	6.2	0.0		0.0	0.0	0.0		0.7	0.0	0.0		1.8	11.2	0.0	0.0
5/4/2012	67.8	86.5	15.2		73.2	110.7	48.4		0.4	0.0	0.0		0.9	0.0	0.0		141.0	197.2	63.7	0.0
5/5/2012	85.8	62.3	10.1		58.2	71.4	45.7		0.0	0.0	0.0		1.1	0.0	0.0		144.0	133.6	55.8	0.0
5/6/2012	5.9	2.5	1.0		18.7	11.2	8.7		0.0	0.0	0.0		0.0	0.0	0.0		24.6	13.7	9.7	0.0
5/7/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0		0.0	0.3	0.0		2.8	0.0	0.0		1.6	0.0	0.0		0.0	0.3	0.0	0.0
5/9/2012	167.4	292.3	247.8		92.2	110.0	132.6		0.0	0.0	0.0		9.9	0.2	0.0		259.6	402.4	380.4	0.0
5/10/2012	41.6	106.9	54.0		12.6	23.3	15.2		0.0	0.0	0.0		7.8	0.1	0.0		54.2	130.2	69.2	0.0
5/11/2012	1.2	78.6	11.4		3.8	24.1	8.0		0.0	0.0	0.0		2.1	0.0	0.0		5.0	102.8	19.4	0.0
5/12/2012	6.1	4.4	0.0		5.3	3.2	0.0		0.0	0.0	0.0		0.0	0.0	0.0		11.5	7.7	0.0	0.0
5/13/2012	18.0	10.8	0.8		6.5	5.3	0.1		0.0	0.0	0.0		0.7	0.1	0.0		24.5	16.1	0.9	0.0
5/14/2012	4.3	13.3	4.4		2.2	3.6	1.5		0.0	0.0	0.0		2.9	0.0	0.0		6.5	16.9	5.9	0.0
5/15/2012	43.8	101.4	9.8		0.0	0.0	0.0		0.0	0.0	0.0		5.5	0.6	0.0		43.8	101.4	9.8	0.0
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.6	12.8	0.0	0.3
5/17/2012	7.8	3.6	0.0	0.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	7.8	3.6	0.0	0.3
5/18/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		1.3	0.0	0.0		0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0		6.7	0.0	0.0		0.0	0.0	0.0		9.2	0.2	0.0		33.3	25.7	3.0	0.0
5/20/2012	241.6	356.5	93.5		152.9	201.7	164.4		0.0	0.0	0.0		7.2	2.3	0.0		394.4	558.2	257.9	0.0
5/21/2012	349.6	269.5	121.5		1.2	1.1	0.0		0.0	0.0	0.0		4.4	0.6	0.0		350.9	270.7	121.5	0.0
5/22/2012	348.2	364.4	257.8		0.0	0.0	0.0		0.0	0.0	0.0		7.1	4.3	0.0		348.2	364.4	257.8	0.0
5/23/2012	19.5	136.1	42.7		0.0	0.0	0.0		0.2	0.0	0.0		6.3	0.2	0.0		19.5	136.1	42.7	0.0
5/24/2012	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.4	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.3
5/25/2012	0.0	6.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		4.0	0.0	0.0		0.0	6.0	0.0	0.0
5/26/2012	19.2	27.7	1.9		36.7	53.1	31.6		0.0	0.0	0.0		1.3	0.0	0.0		56.0	80.9	33.6	0.0
5/27/2012	1,058.1	802.9	331.5	1,485.7	347.7	375.3	330.5	955.7	2.3	0.0	0.0	1,150.4	8.1	5.2	0.0	168.7	1405.9	1178.2	662.0	2441.4
5/28/2012	1,140.7	1,622.0	780.3	2,561.3	489.8	756.9	1,021.6	1,435.4	1.2	0.0	0.0	1,099.0	22.4	10.1	0.3	311.3	1630.5	2378.9	1801.9	3996.7
5/29/2012	166.4	203.8	133.1		0.0	0.0	0.0		0.0	0.0	0.0		1.6	1.3	0.0		166.4	203.8	133.1	0.0
5/30/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.4	0.0	0.0	0.0
Total	3,823.8	4,595.2	2,119.8		1,311.9	1,759.4	1,808.4		7.0	0.0	0.0		110.3	25.3	0.3		5135.7	6354.6	3928.1	0.0

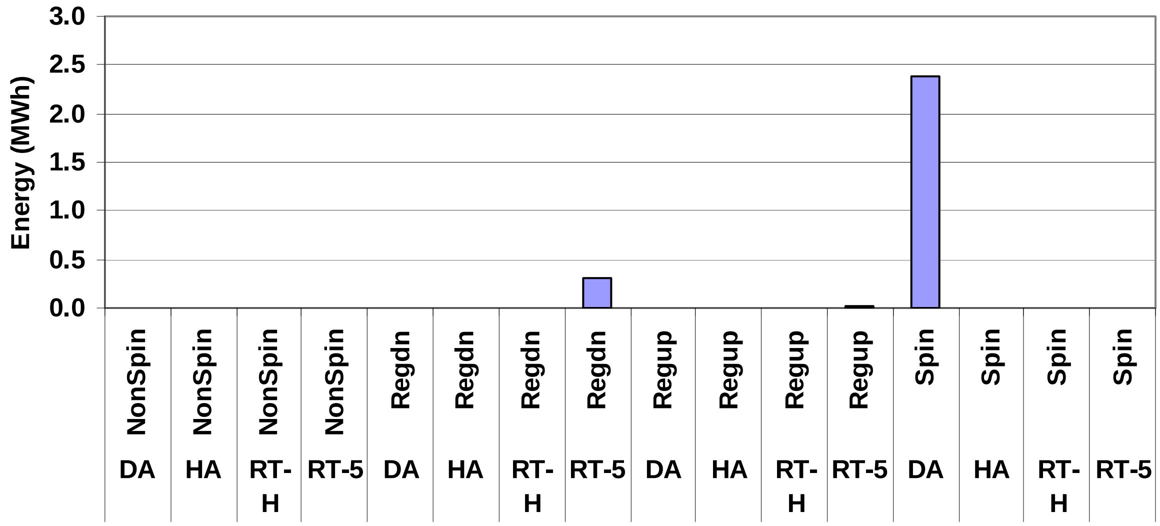

Figure C-14: May 16th Operational Issues based on 2006 Load Shapes

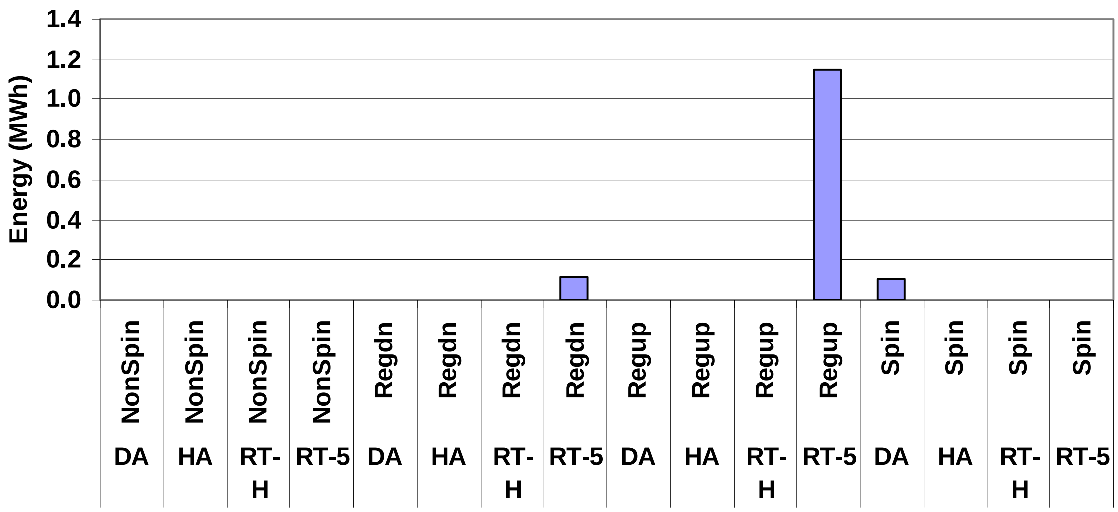

Figure C-15: May 17th Operational Issues based on 2006 Load Shapes

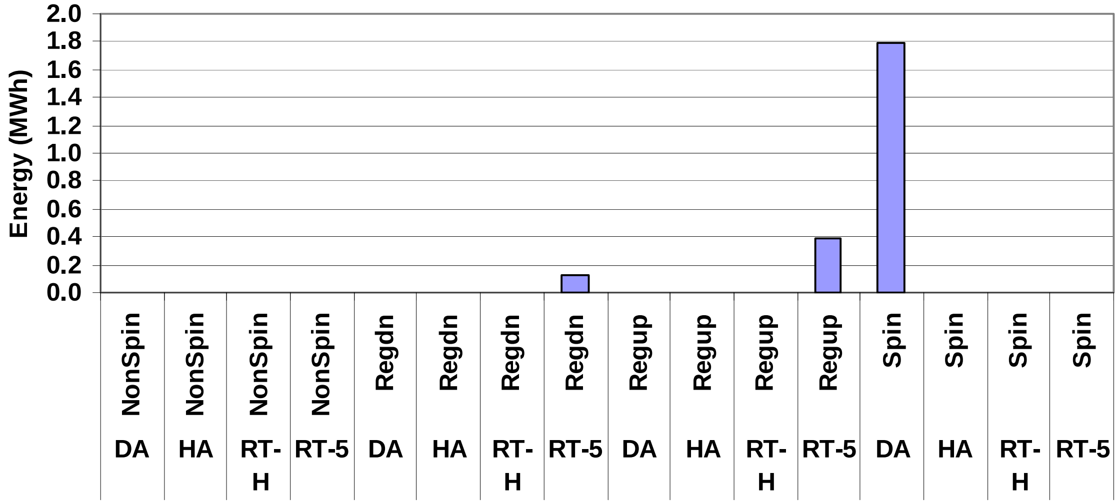

Figure C-16: May 24th Operational Issues based on 2006 Load Shapes

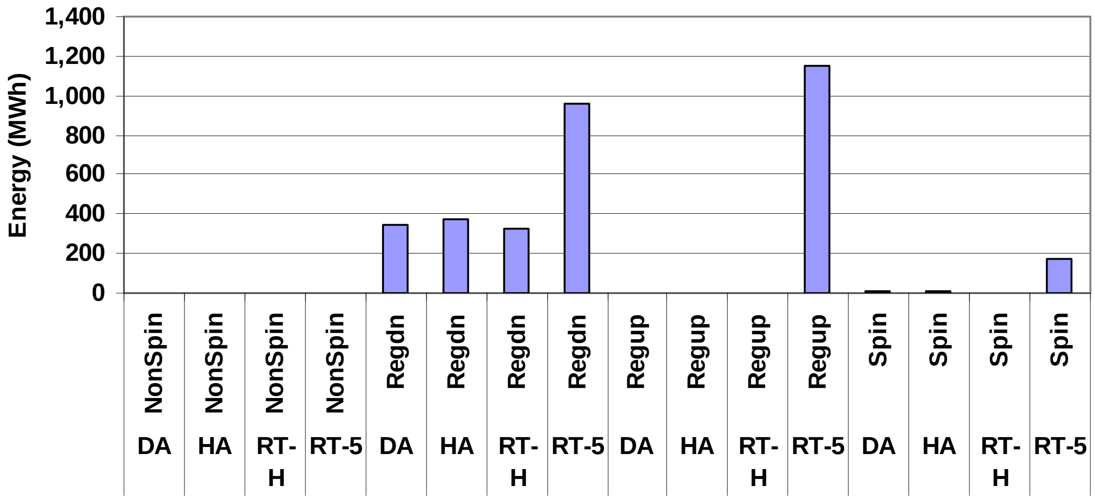

Figure C-17: May 27th Operational Issues based on 2006 Load Shapes

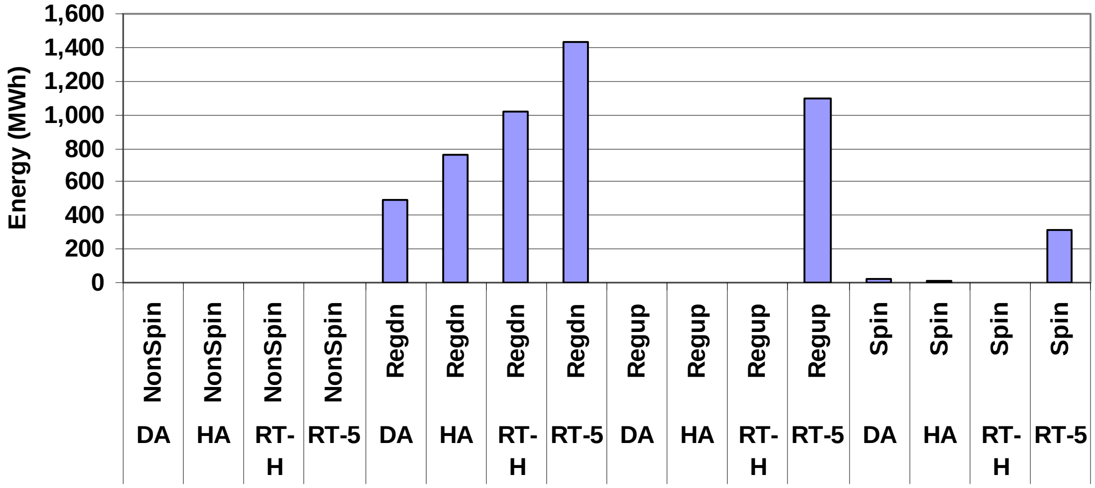

Figure C-18: May 28th Operational Issues based on 2006 Load Shapes

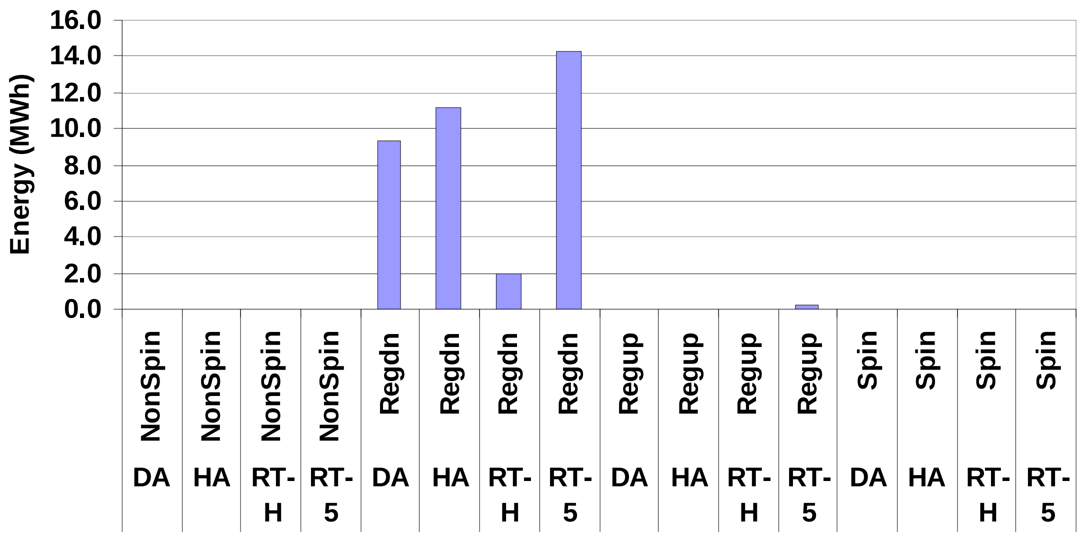

Figure C-19: May 22nd Operational Issues based on 2007 Load Shapes

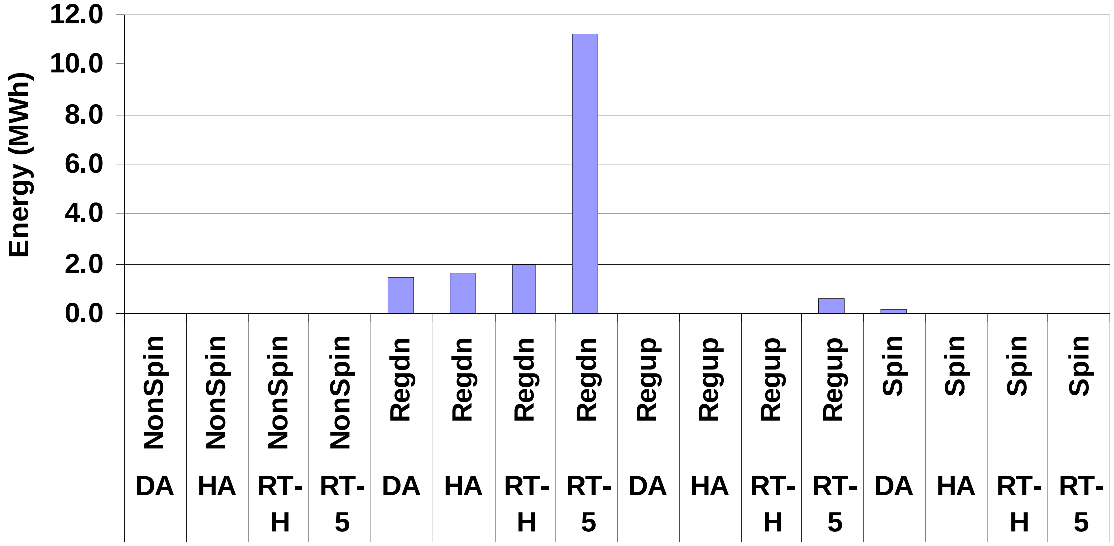

Figure C-20: May 23rd Operational Issues based on 2007 Load Shapes