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# DRAFT: Review of PG&E Renewable Integration Model and CAISO 33% RPS Analysis

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**Outline:**



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## Abbreviations and Acronyms

| | |
|---|---|
| CAISO | California Independent System Operator |
| CPUC | California Public Utilities Commission |

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|---|---|
| CT | Combustion turbine |
| DA | Day-ahead |
| GE | General Electric |
| IFM | Integrated forward market |
| IOU | Investor owned utility |
| LTPP | Long-Term Procurement Proceeding |
| NQC | Net qualifying capacity |
| OTC | Once-through cooling |
| RIM | Renewable Integration Model |
| PG&E | Pacific Gas & Electric Company |
| PRM | Planning reserve margin |
| QSS | Quasi-steady state analysis |
| WECC | Western Electricity Coordinating Council |
| WWSIS | Western Wind and Solar Integration Study |

## Executive Summary

The California Public Utilities Commission (CPUC) asked the Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory (NREL) to review two ongoing 33% renewable energy integration studies in California. One study, led by the California ISO, uses a detailed production cost model (PLEXOS) and will provide detailed results for a limited set of scenarios. The second is an Excel spreadsheet tool called the Renewable Integration Model (RIM) that is meant to estimate integration needs and costs in a simple, transparent way under a wide variety of user-driven assumptions.

The purpose of the review is to understand the differences and similarities of the methods used in the two studies, determine if there are any major problems with using the studies to inform the CPUC in evaluating integration costs and procurement plans of the Investor Owned Utilities (IOUs), and to highlight similarities or differences to other integration studies in the U.S. or internationally. This is not a comprehensive review of each assumption or aspect of the studies' methodologies. Instead we focus on particular issues that may have a significant impact on the results or steps that can help interpret the output of the studies.

The studies are important in providing an assessment of the needs and impacts of getting to a 33% RPS in California. It is important to note that methods used in integration studies are continually evolving and there is not yet a standard method for conducting these studies. Relative to many of the existing integration studies, the California studies are innovative in various ways, including the high level of renewable penetration analyzed and a focus on investigating the interaction between the operational flexibility service requirements (what is called the Step 1 results) and the need for flexible capacity beyond what would be needed to meet the planning reserve margin (part of the Step 2 results). The results of the studies will be useful to other state commissions or policy makers interested in assessing variable renewables like wind and solar power.

One of the important aspects of these studies is that they are focused on ensuring the reliability of the power system in a future study year (2020) where the only resources that are initially added to the existing system are new renewables and sufficient new conventional capacity to meet the future peak load and planning reserve requirement *net of the capacity contribution attributed to the renewables* (also known as the capacity credit or net qualifying capacity in California). In other words, the variable renewable generators in this study are assumed to displace a portion of other conventional capacity that would have been built to meet the peak load and planning reserve margin if the variable renewables were not built (based on the estimated net qualifying capacity of the variable renewable generators).

The studies then evaluate if the system can be operated reliably despite the uncertainty and variability of the output from the variable renewables. The California ISO study directly simulates individual power plants in California and the rest of WECC in an hourly chronological production cost model. The uncertainty and variability of the load and variable renewables is represented by load following and regulation reserves ("operating flexibility service requirements"). The CAISO uses the model to simulate how the system will operate with increased variable renewables, and highlights periods where insufficient resources are available to meet the load and operating flexibility service requirements (leading to violations of reserve targets). The violations can occur due to insufficient aggregate ramping capability, insufficient ability of on-line generators to be backed down due to minimum generation constraints, too long start-up or shut-down times for conventional units, or insufficient generating capacity. The CAISO then adds new flexible generating units (combustion turbines) to the system until the system has sufficient flexible resources to operate without violations in reserve targets. This new capacity added on top of the resources required to meet the peak load and planning reserve margin (accounting for the net qualifying capacity contribution of the variable renewables) is referred to as the integration need. The cost of the combustion turbines attributed to integration need represent a fixed cost component of the overall integration cost.

It is important to recognize that the operating flexibility service requirements are an important input into the identification of periods where violations of the reserve targets will occur and additional new capacity is added to mitigate the violations (the integration need), but the operating flexibility service requirements are not necessarily the only driver of the estimated integration need in the CAISO analysis. It is therefore not certain that operating flexibility service requirements will be proportional to integration need across a wide range of different variable renewable portfolios to meet a 33% RPS.

The RIM model simplifies this process in an hourly spreadsheet tool. RIM similarly accounts for how the variability and uncertainty of loads and variable renewable generators impact the operating flexibility service requirements. RIM, however, implicitly assumes that the existing generation units in a base year (2008) cannot increase its provision of energy or operating flexibility services in any hour within the future study year (2020). This assumption is used because RIM does not directly account for the capability or limitations of individual generating units in providing flexibility (which the CAISO method accounts for through the use of a production cost model) and the RIM developers rightly argue that the other extreme of assuming that all units are *perfectly flexible* would also be incorrect. This conservative assumption in the RIM model about the severely limited flexibility of the existing units leads to the addition of new power plants to provide additional flexibility. Analysis of results from the RIM model indicates that this assumption particularly impacts the integration need when solar generation is included in the variable renewable portfolio, even when variable renewables are assumed to be perfectly forecastable and not to vary within the hour. RIM reports very high integration costs for the 33% RPS case provided as a starting point with the model (which includes a large contribution of solar) that far exceed the integration costs reported elsewhere in previous integration studies. The conservative assumptions in RIM about existing flexibility are likely a key contributor to the higher cost estimate.

Table ES 1 summarizes the key areas that warrant further evaluation in the California studies. Overall, as noted, the RIM model currently does not adequately capture the flexibility of the existing generation. Without modification to the current model formulation, RIM may not be useful for estimating variable renewable integration costs and estimating the quantity of new units needed to provide increased flexibility to integrate variable renewables, particularly for scenarios with high solar penetration. The highest priority recommendation is to therefore focus on improving the characterization of the flexibility of the existing system in the RIM model.

Because the CAISO study uses a detailed chronological production cost model, its results can better account for the flexibility of the existing system. With regards to the quantification of the operating flexibility service requirements, the RIM and CAISO approaches both adequately assess the seasonal maximum operating flexibility service requirements. Applying these maximum requirements to all hours of a season, however, can lead to a situation where reserves are held in the models in preparation for conditions that are not physically possible. Holding resources in reserve for infeasible events appears to overstate the integration need for wind in the RIM model. The hourly estimate of operating flexibility service requirements in the CAISO approach truncates the range of forecast errors to ensure that the hourly operating flexibility requirement is based on physically possible events. The base methodology used by the CAISO however applies the maximum seasonal requirement to the hour the day (i.e. a seasonal maximum is estimated for twenty-four hours per season) which, like RIM, may lead to the CAISO holding reserves for infeasible events, particularly during individual hours when renewable production is low. The difference in the integration need between the base methodology and a sensitivity study by the CAISO that used the original hourly requirements may in part be explained by the issue of infeasible forecasts. This issue should be evaluated in more detail for both RIM and CAISO. In addition, this issue highlights that the interaction of hourly variable generation profiles, the correlation with load, and the timing of operational flexibility service requirements together impact the resulting integration need. The seasonal maximum operating flexibility service requirements (the Step 1 results) in isolation should not automatically be assumed to be directly proportional to the integration need (part of the Step2 results) across a broad range of variable renewable portfolios. Additional detailed analysis is needed to determine if there might be consistent trends between seasonal maximum operating flexibility service requirements and integration need.

Finally, the CAISO does not currently address day-ahead forecast errors for load or variable renewables in their analysis. Day-ahead forecast errors may be important for high penetrations of variable generation. The degree to which integration need and costs might be impacted by day-ahead forecast errors should be assessed. The additional issues in Table ES 1 are lower priority because they can be addressed through sensitivity studies using the current modeling framework.

**Table ES1. (Table 2 in main text) Issues to consider in using California studies to inform CPUC process**

| Study | Issue | Priority | Steps Required to Resolve | Comments |
|---|---|---|---|---|
| **RIM** | Base year dispatchable resources cannot increase output or contribution to reserves in study year | High | Revision of Step 2 portion of model. Potentially requires large revision to model. | Severely impacts results for solar, some impact on wind. Leads to overstatement of "integration needs" |
| **RIM** | Incorporate flexibility characteristics and constraints of conventional resources into model | Medium | Inclusion of generator parameters related to flexibility (ramp rate, min-gen, start-up time) in evaluation of integration need. Potentially requires large revision to model. | Aside from assumption that base year resources cannot increase output in the study year, RIM does not characterize the flexibility of new or existing units. |
| **RIM and CAISO** | Ensure operating flexibility service requirements are held based on feasible forecasts | Medium | RIM - Revision of Step 1 methodology; CAISO – detailed examination of current methodology for converting Step 1 results into Step 2 inputs | RIM currently adds units to provide reserves for physically infeasible events. CAISO may do same when using maximum seasonal load following requirements in Step 2. |
| **CAISO** | Evaluate implications of day-ahead forecast errors (not currently modeled by CAISO) | Medium | Detailed modeling of unit-commitment (Step 2) and day-ahead forecast errors (Step 1) may require significantly more data, revisions to model, and additional processing time. Quick evaluation might be done with post-processing of results from existing model. | Large day-ahead forecast errors may require commitment of long-start units that would otherwise not be (or remain) committed, and/or require additional fast- or medium-start units in the system. |
| **RIM and CAISO** | Adequately incorporate benefit of geographic diversity in hour-ahead | Low | CAISO is investigating this issue and should continue to focus on it. Diversity-related refinements could also be applied to RIM. | Improved forecast errors appear to reflect expected errors for persistence forecast of geographically diverse resources, but detailed evaluation is |

| | | | | |
|---|---|---|---|---|
| | forecast error | | | warranted |
| **CAISO** | Evaluate options to increase access to existing flexibility or decrease forecast errors | Low | Develop and analyze additional sensitivity scenarios to evaluate relative to the reference case. | Reducing institutional barriers to accessing flexibility of units outside of CA, providing incentives to operate existing units in ways that are more flexible than currently operated, accessing flexibility of run-of-river hydro, and improving forecasts may all potentially substitute for new "integration need". |
| **CAISO** | Evaluate ability of units built in study year (2020) for "integration need" to contribute to "reliability need" in future years (e.g. 2025) | Low | Develop additional sensitivity scenarios to evaluate relative to the reference case. | If new units are needed to increase overall system flexibility, the same units may also help meet future load growth. Use system that addresses all violations in 2020 but increases the load to 2025 levels in sensitivity study to determine if the 2020 system is adequate to also meet increased loads |

In summary, the major simplification of the RIM study relative to the CAISO study is that the RIM model assumes that units that existed in the base year (i.e. 2008) cannot provide more energy or operating flexibility services in each hour of the study year (i.e. 2020) than they provided in the same hours of the base year, while the CAISO uses a production cost model to determine the least cost dispatch of most units in both the base year and study year. The production cost model used by the CAISO can account for the flexibility (in terms of ramp-rates, minimum generation limits, and start-up times) for both existing and new units. The production cost model used by the CAISO is an appropriate tool for informing the questions of the CPUC. On the other hand, without revisions, the major simplification in RIM presents a fundamental problem for using the results of the RIM analysis to determine integration need and costs. . The simplification appears to have a larger impact on the integration needs and costs of solar than it does for wind. The simplification therefore also presents a fundamental problem for relative comparisons of integration needs and costs across different renewable scenarios.

The seasonal maximum operating flexibility requirements estimated by the RIM and CAISO are based on appropriate methodologies specifically suited to the timelines used in the California markets. These results are not out of line with other integration studies from other parts of the U.S. and Europe. Using these maximum seasonal requirements in every hour of the year, however, does lead to hours in the RIM model where the operating flexibility service requirements exceed the maximum physically possible change in output from the variable renewable resources. This should be revised in RIM and should be further evaluated in the CAISO model.

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## 1. Overview of CPUC Request

The California Public Utilities Commission (CPUC) is conducting a 2010 long-term procurement proceeding (LTPP) which includes evaluation of new flexible resources ("flexible resource needs") to ensure adequate capabilities to operate the power system in the 2010-2020 timeframe. These flexible resource needs are driven both by the need to ensure adequate system flexibility to integrate increased wind and solar generation and the need to offset anticipated retirements of some power plants that use once-through cooling (OTC). In this proceeding, the CPUC will consider authorization of flexible resource procurement by the investor-owned utilities (IOU) under its jurisdiction. A related question is what are the relative costs for different variable renewable resource portfolios based on the flexible resource needs and operational changes to integrate the generation into the California power system.

Two different ongoing studies are available to the CPUC and other stakeholders to examine flexible resource needs and integration costs for portfolios of renewable resources to meet a 33% renewable portfolio standard in 2020 (the “California studies”). The first is a detailed analysis led by the California Independent System Operator (CAISO) using a chronological production cost model (PLEXOS) with hourly time resolution. As discussed later, chronological production models are the primary analytical tool used in most state-of-the-art operational studies of future scenarios with high penetration of variable renewable resources (loosely referred to as “integration studies”). Additional hourly and within-hour analysis of synthetic load and variable renewable forecasts and production profiles is performed outside of the production cost model in order to develop simulation inputs that represent the variability and uncertainty associated with variable renewable generation and loads within the hourly time resolution of the production cost model. These within-hour characteristics are represented as additional hourly operating reserve requirements in the production cost model (called “operating flexibility service requirements”). As with other integration studies, the chronological production cost model includes a high degree of detail in load and generation characteristics (with a more simplified characterization of transmission constraints) and produces an in-depth evaluation of changes in the way the power system will operate with increased variable generation. This high degree of detail, however, leads to very intensive efforts to develop renewable resource and load profiles and to process the simulation results for each scenario. A limited set of results from the CAISO analysis will eventually be available to the CPUC and other stakeholders.

The second study is a simplified, transparent, Excel-based spreadsheet tool called the Renewable Integration Model (RIM) developed by Pacific Gas & Electric (PG&E) and the Brattle Group. The tool estimates the total flexible conventional capacity needs and integration costs for user-defined portfolios of variable renewable resources. The starting-point variable renewable generation profiles and parameters for characterizing the within-hour variability and uncertainty in RIM were developed based on inputs similar to the CAISO analysis. RIM can quickly process alternative variable renewable resource portfolios and parameters, thus enabling a broad array of scenarios that can be analyzed by the CPUC and other stakeholders. The model translates the uncertainty and within-hour variability of both loads and variable renewable resources to increased operating reserve requirements for each user-defined renewable resource portfolio (again called "operating flexibility service requirements"). As will be described later, RIM then estimates the total need for new flexible conventional resources as the conventional generating capacity needed to meet any increase in hour-by-hour load between a base year (2008) and a study year (2020) plus the increased operating flexibility service requirements that is not covered in each hour by variable generation. RIM separates this need for new flexible conventional resources into the "reliability need" and "integration need". The reliability need is calculated as the amount of the new flexible conventional resources required to meet the peak incremental load plus planning reserve margin after accounting for the net qualifying capacity of the variable renewables. The "integration need" is the remainder of the total new flexible resource need that is not attributed to "reliability need". RIM also estimates changes in production costs to manage a portion of the variability and uncertainty based on simplified representations of start-up costs, part-load efficiency penalties, and ramping costs.

Based on the needs of the CPUC in the LTPP and the status of the two California studies, the CPUC presented Berkeley Lab and the National Renewable Energy Laboratory (NREL) with the following questions:

1. How do the CAISO analysis and the PG&E RIM compare to each other? What are the major simplifications that the RIM uses relative to the CAISO approach?

2. Are there any fundamental problems with using the results of these California studies to a) estimate operating flexibility service requirements (referred to as Step 1 results) and flexible resource need and associated cost (referred to as Step 2 results) for different renewables scenarios, and/or b) estimate the relative difference in operating flexibility service requirements and flexible resource need and costs between scenarios?

3. Are there other examples of tools and studies that are used to inform similar questions in other regions of the U.S. or internationally? How do these approaches compare to the California studies? Can these tools and studies be used to improve the California studies?

The remainder of this memo provides an overview of the California studies and addresses the questions asked by the CPUC. Section 2 reviews the studies and highlights key differences in the approach used to estimate the flexibility needs with increased variable renewable penetration and the costs of meeting those needs. All numerical results presented for the RIM model in this and following sections are from the RIM model version 2.1. Section 3 highlights differences between the current studies and other integration studies and tools that have been used throughout the U.S. and internationally. Based on the objectives of the CPUC and the review of the California studies relative to other integration studies, Section 4 presents important caveats to using the California studies to estimate integration costs and inform procurement plans. Finally Section 5 concludes with our general recommendations.

## 2. Review of California Studies

The CAISO and RIM studies both use two primary steps to estimate the flexible resources required to maintain secure operation of the power system and the integration costs of a portfolio of renewable resources. First, the studies characterize the variability and uncertainty of the net load[1] and calculate the resulting operating flexibility service requirements (Step 1). Second, the studies estimate the increased production costs to manage the increased variability and uncertainty and the flexible conventional resources need in a 2020 study year for each renewable resource portfolio (Step 2). Some of the more important differences and similarities between the CAISO approach and the RIM tool that are described in this section are summarized in **Error! Reference source not found.**.

**Table 1. Summary of comparison between CAISO approach and RIM tool**

| | Does the approach… | CAISO | RIM |
|---|---|---|---|
| **Step 1: Operating flexibility service requirements** | Include regulation and load following? | ✓ | ✓ |
| | Include day-ahead forecast error? | ✗ | ✓ |
| | Separately estimate regulation up from regulation down, and the same for load following? | ✓ | ✗ |
| | Force wind and solar forecasts to be within physical limits? | ✓ | ✗ |
| | Adjust wind variability and forecast error according to the expected wind production level? | ✗ | ✗ |
| | Adjust maximum solar variability and forecast errors according to the position of the sun? | ✓ | ✓ |
| **Step 2: Needs and costs to manage variability and uncertainty** | Dispatch in a least cost manner most units that existed in base year (2008) during the study year (2020)? | ✓ | ✗ |
| | Directly account for limited ramp rates, minimum generation, and start-up time of conventional units and energy limits of hydro units? | ✓ | ✗ |
| | Estimate increased variable production costs associated with increased reserves? | ✓ | ✓ |
| | Start with sufficient existing and planned conventional capacity to meet load and planning reserve margin net of qualifying capacity of wind and solar? | ✓ | ✓ |
| | Add additional new units called "integration capacity need" if initial resources are not sufficient to meet net load and operating flexibility services? | ✓ | ✓ |
| | Verify that new resources added for integration capacity need are sufficiently flexible? | ✓ | ✗ |

### *2.1 Step 1: Estimate the operating flexibility service requirements*

The methods used to characterize the variability and the uncertainty of the net load and calculate the resulting operating flexibility service requirements, the first step, is similar between the CAISO and RIM studies. Both studies focus only on the net variability and uncertainty at the system level meaning that any increase in load, for example, that occurs at the same time as an increase in variable renewable generation is netted out. Both

[1] The net load is the load minus the generation from the variable renewable resources.

studies similarly characterize variability and uncertainty around hourly load and variable renewable production data as being met with an increase in balancing reserves.[2] This increase in reserves is called the "*operating flexibility service requirements*" in the RIM and in this document. An increase in *regulation reserves*, for instance, is used to manage the combined increase in variability between flat 5-min economic dispatch levels and the underlying minute-to-minute variations *plus* the increase in uncertainty regarding the 5-min economic dispatch instructions relative to the actual 5-minute net load, reflecting errors in very short term (<10 minute) forecasting. An increase in *load following* reserves is used to manage the combined increase in deviations between flat hourly schedules and each of the 5-min economic dispatch instructions *plus* the increase in uncertainty when setting hourly schedules before the operating hour. In addition to these regulation and load following balancing reserves, RIM estimates the *day-ahead forecast error* and similarly assumes that additional balancing reserves need to be held in each hour to account for day-ahead forecast errors.[3] The CAISO on the other hand does not address day-ahead forecast errors in their 33% RPS analysis.

Both the CAISO and RIM methods for characterizing the variability and uncertainty (and therefore the operating flexibility service requirements) rely on statistical relationships – namely variance and correlation – to estimate the variability and uncertainty of the net load. The RIM model directly estimates the variance of the net load based on the

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[2] CAISO indicates that the load-following requirement calculated in Step 1 is treated as an "additional capacity reservation" (CAISO, 2010 p 71). Regulation up and down is also an additional capacity reservation.

[3] In RIM the day-ahead forecast error measures only the difference between the day-ahead forecast and the hour ahead schedule. That way hour-ahead forecast errors (the difference between the hour ahead schedule and the actual hourly average net load) are not double counted.

variance of the load and the variable renewable resources for each of four seasons. For wind, RIM does not distinguish forecast errors based on the time of day or the production level of the wind resources when characterizing the contribution of wind to the variance of the net load.[4] For solar, RIM adjusts the variance solar on an hourly basis in proportion only to a seasonal variance estimate and the seasonal average solar during a particular hour of the day.

One drawback to the seasonal variance approach used by RIM is that RIM implies that if, for example, 95% of the summer hour-ahead wind forecast errors are up to 16% of the nameplate capacity of wind,[5] and if reserve requirements are being set at the 95% level, then the system operator is modeled as needing to be able to accommodate an over-forecast or under-forecast of 16% of wind *nameplate capacity* in *any* hour of the summer (Figure 1). However, if wind production is forecasted to be only 10% of the nameplate capacity of wind during a particular summer hour with high load, it is not physically possible to have an over-forecast of 16% of wind (at most the over-forecast can be 10% of nameplate if the actual wind output were to drop to zero). A way to correct for this is to have the load following requirement in RIM depend on variable renewable production in any particular hour. Since the RIM Step 1 methodology does not vary the calculated load following requirement depending on the expected wind production level, it may be over-stating the load following and day-ahead contribution to the operating flexibility service requirements during times when the wind is expected to produce little power

[4] RIM does allow the user to specify the correlation between the load and variable renewable resources or between the different variable renewable resources. Hour-ahead forecast errors for “new wind” and “existing wind” can therefore be modeled as perfectly correlated, uncorrelated, or somewhere in between.

(which is likely to be correlated with times when the net-load is expected to be high and capacity is scarce).[6] This limitation was found to artificially increase the integration need and therefore the integration costs for high wind penetration scenarios.[7]

In contrast, the CAISO approach uses the variance to define the spread of an assumed truncated normal distribution for the uncertainty of the load and variable renewable resources. The CAISO approach truncates the distribution of forecast errors to either 3 standard deviations from zero or in a way that it ensures that any forecast error could physically occur (meaning that the CAISO approach checks that wind and solar generation could actually reach production levels that generate any particular forecast error), Figure 2 (Makarov et al., 2009; CAISO, 2010 page 48). Following from the previous example regarding forecast errors for RIM, the CAISO approach would truncate the possible hour-ahead forecast errors to 10% on wind nameplate capacity if the hour ahead forecast was for wind to generate at 10% of its nameplate capacity (instead of allowing it to be greater than 10% like RIM would do).

The CAISO Step 1 approach uses distributions forecast errors and one-minute variable generation and load profiles to estimate the net load following and regulation requirement

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[5] Approximately two standard deviations if the standard deviation of the hour-ahead forecast error is 8% for wind during the summer season.

[6] For a more concrete example, we examined the base reference case of the RIM model (run with the "solar adjustment model" option in RIM). On the day with the peak net incremental load and operating flexibility requirement (Sept 3, 20:00) the model includes 560 MW of load following and day-ahead forecast reserves for the load alone. With the addition of the variable renewables the model adds an additional 1,725 MW of load following and day-ahead forecast error reserves. The total variable renewable energy forecasted for that hour, however, was only 1,588 MW. RIM therefore holds 137 MW of conventional resources in reserve **above** the amount of total wind and solar forecast to appear at that time. In a worst situation the variable renewables could drop to zero output, but RIM would still require additional conventional capacity

using a Monte-Carlo simulation.[8] CAISO uses the Monte-Carlo simulation to estimate the variability and uncertainty of the net load for each hour of each day based on seasonal variance estimates for load and wind and variance estimates that depend on cloud conditions for solar. It also separates the operating flexibility service requirements by direction. Load following up, for example, is estimated separately from load following down. This is important since preliminary analysis elsewhere indicates that forecast errors and variability may be asymmetrical at different production levels. When wind production levels are low, the impact of wind on load following *down* requirements (i.e. other generation needed to be ready to decrease its output in case winds suddenly pick up) may be much greater than the impact of wind on load following *up* requirements (i.e. other generation needed to be ready to increase its output in case wind decreases from its already low level). The RIM model does not separately estimate the operational flexibility requirements according to the direction.

Even though the CAISO method ensures that forecast errors are physically possible when in Step 1 it calculates load-following and regulation requirements for each ***individual*** hour based on ***that hour's*** wind, solar, and load levels, the base CAISO methodology then

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to be held in reserve in case the variable renewables dropped further (which is of course not physically possible). A more extreme example is described in the High Wind Example in the Appendix B.

[7] See the High Wind Example in the Appendix B for a detailed explanation.

[8] Monte-Carlo simulation is a technique that uses a high number of random samples from probability distributions of several different uncertain data to estimate the probability distribution of a final calculation based on the uncertain data. The advantage of the Monte-Carlo simulation is that the underlying distributions of the uncertain data can be captured in the final distribution whereas direct calculations of the variance (as used in RIM) does not indicate the shape of the final distribution. The Monte-Carlo simulation also incorporates auto-correlation terms such that a forecast error from a previous hour affects the forecast error in the next hour.

translates the Step 1 results into the Step 2 analysis by estimating the seasonal maximum[9] operating flexibility service requirement from *all* the 90+ individual hours in the season for a particular time of day (i.e. a seasonal maximum requirement for all noon hours), regardless of the renewable production levels. This "seasonal maximum operating flexibility service requirement" may undo the careful calculations in the Monte-Carlo simulations in Step 1 and, like RIM, lead to operating flexibility service requirements in Step 2 being based on forecast errors that are infeasible in some of the individual days being modeled in the Step 2 production simulation, particularly when variable renewable production is very low (and the net load is potentially high).[10] The CAISO has tested an alternative sensitivity study to the base methodology that uses the actual "hourly operating flexibility service requirement" for each individual hour in the Step 2 analysis. This alternative hourly methodology ensures that the operating flexibility service requirement in each hour is based on feasible forecasts given the variable renewable production in that hour. Thus it is important that RIM and CAISO carefully assess the physical feasibility of forecast errors that drive the level of operating flexibility service requirements calculated over a range of production levels of the variable renewables.

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[9] "Maximum" in the CAISO documentation and in this document refers to a particular percentile, generally the 95th percentile but alternative percentiles (namely the 90th percentile) are also evaluated as the maximum.

[10] The CAISO developed an alternative methodology that uses an hourly estimation of the load following requirement instead of the seasonal requirement for a particular hour of the day. This alternative methodology should correctly ensure the feasibility of forecast errors in any particular hour and may therefore better represent integration needs. This is an area with little existing research and deserves particular attention.

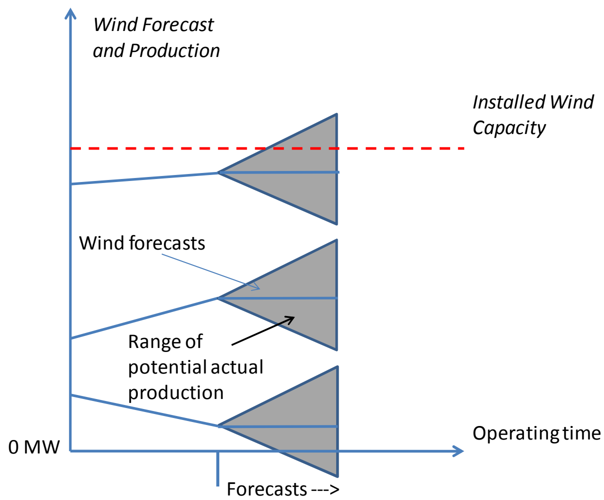


**Figure 1. The RIM approach to estimating wind forecast errors can sometimes lead to infeasible production levels that exceed the installed capacity of wind or lead to "negative" production.**

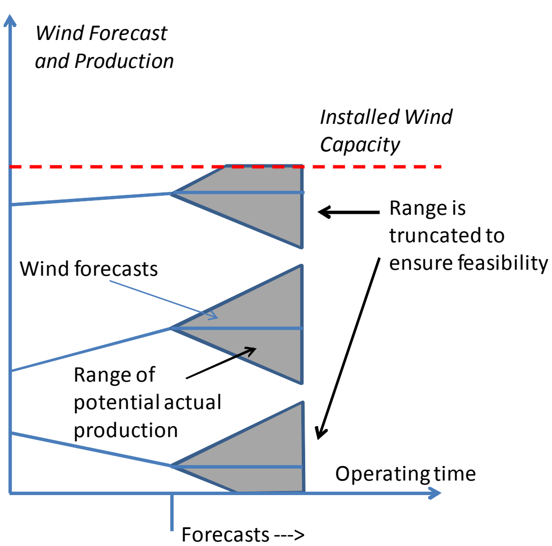


**Figure 2. The CAISO methodology for translating forecast errors into load following requirements in Step 1 truncates the range of forecast errors to ensure all levels of forecasted production are feasible.**

Aside from these differences, given similar variance and correlation estimates, the RIM and CAISO methods for estimating the variability and uncertainty of the net load should across a broad range of variable renewable portfolios lead to fairly similar estimates of the maximum seasonal regulation and load following requirements on average. PG&E

presented a comparison of results from a particular scenario that shows agreement between the two methods for estimating the regulation and load following requirement in the up-direction.[11] Based on the similar foundations of the methodologies they are expected to be similar for other alternative variable renewable scenarios. The CAISO method will include higher time resolution, more information about the distribution of the net load variability and uncertainty, and separate estimates of the operating flexibility service requirements by direction (up or down).[12] The RIM method will also characterize the DA forecast error which is not addressed by the CAISO. It is important to recognize, however, that the seasonal maximum operating flexibility service requirements identified in the Step 1 results are and intermediate result and are not the sole driver of the integration needs and costs for a portfolio of variable renewable resources. The analysis required to translate the Step 1 results into an identification of the integration need and costs is called the Step 2 process and is summarized for the CAISO and RIM model in the following section.

### *2.2 Step 2: Needs and costs of resources to manage increased variability and uncertainty*

The biggest difference between the CAISO and RIM studies is the treatment of the flexibility of the existing system. As will be explained, this is related to the use of the total net load in 2020 by the CAISO and the use of only the incremental load and variable

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[11] Slides 23-24 from PG&E presentation to the CPUC at the August 24-25, 2010 workshop.
[12] Although the CAISO approach yields more information about the shape of the distribution of the net load forecast error and variability, the CAISO approach begins with an assumption that the forecast error and variability distributions follow a truncated normal distribution. Analysis of the distribution of sub-hourly and hourly changes in wind (Wan, 2005) and solar (Mills and Wiser, 2010) indicate that normal distributions are not necessarily a bad approximation for several aggregated sites, but more detailed

renewables in the RIM. There are also other ways, described below, in which the two models use the operating flexibility service requirements from the Step 1 analysis and the hourly load and variable renewable production profiles to estimate of the need for new flexible resources and the resulting integration costs.

The *total load* in 2020 and the total load in 2008 are shown for each hour of one week in September in Figure 3. The increase in the hourly load between 2008 and 2020 is the *incremental load*, also shown at the bottom of Figure 3. The CAISO analysis uses a production cost model, PLEXOS, to evaluate the cost and feasibility of meeting the total load in the year 2020 net of the hourly production of the variable renewables, i.e. the net load, while simultaneously meeting the normal operating reserves plus the additional operating flexibility service requirements to accommodate the mix of variable renewables. The net load in 2020, used by the CAISO, is compared to the net incremental load from 2008 to 2020 used in the RIM model in Figure 5.

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monitoring of wind and solar within California should be used to verify the assumption of normality for wind and solar variability and forecast errors.

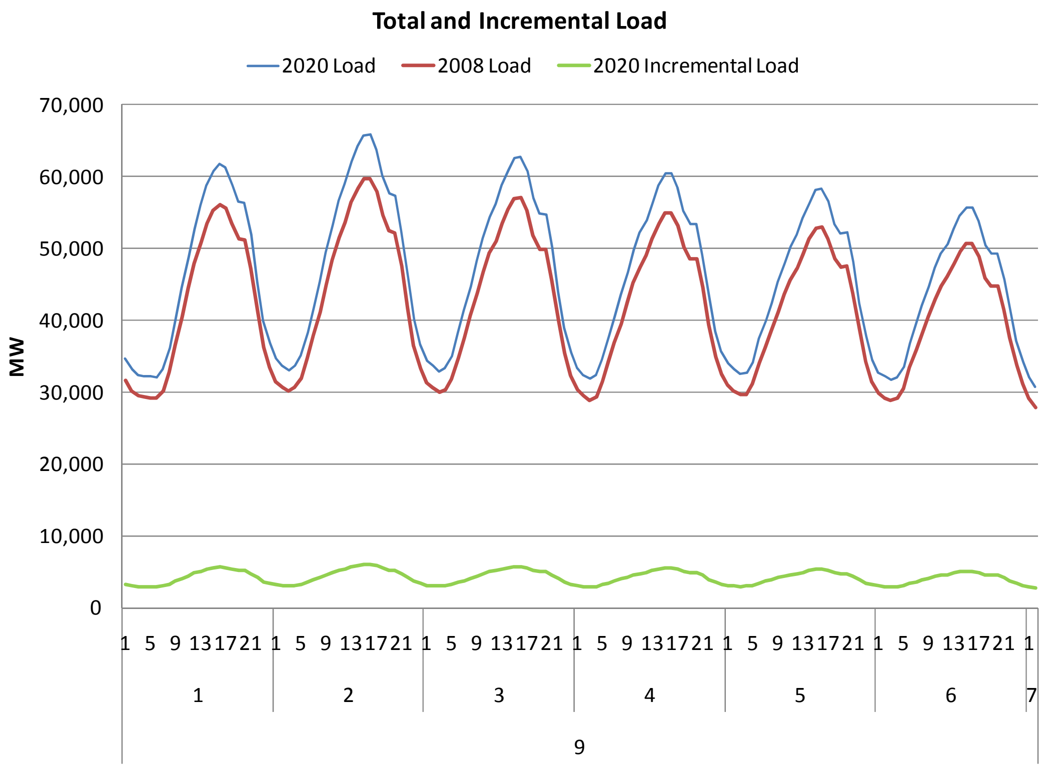


**Figure 3. Example of one September week of hourly total load in 2008, total load in 2020, and incremental load between 2020 and 2008.**

*2.2.1 CAISO Approach*

The PLEXOS dispatch model used by the CAISO attempts to meet the hourly net load and operating flexibility service requirements in 2020 in a least cost manner using the capacity and flexibility of the system available in 2020. The 2020 system starts with the existing and planned generation in 2020 plus sufficient new units to meet the load and planning reserve margin[13] net of the capacity contribution of the renewable generators (or the net qualifying capacity, NQC). The conventional generation added to meet the load and planning reserve margin net of the capacity contribution of the renewables is called the *"reliability need"* (Figure 4). The CAISO study then optimally allocates generation schedules to conventional generators such that the hourly net electricity demand, the estimated regulation and load following requirement (the operational flexibility services), and the contingency reserves (spinning and non-spinning) are met in a least cost manner. PLEXOS both evaluates the ability of the 2020 system to meet the net load and reserve requirements and quantifies the changes to the ways that the units will be operated with high variable generation. PLEXOS accounts for operational constraints such as start-up time, ramp rates,[14] minimum generation limits, and daily energy limits on each individual conventional unit.[15,16]

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[13] In California the planning reserve margin (PRM) is 15-17% above the forecasted peak load. CAISO uses 17% as the PRM (CAISO Aug. 24-25, 2010 presentation to the CPUC, slide 63.

[14] The ramp rates used by the CAISO in the PLEXOS model appear to be slightly lower than the ramp rates used in the Western Wind and Solar Integration Study:

| Technology | WWSIS | CAISO |
|---|---|---|
| **CCGT** | 3.8%/min | 1.5%/min |
| **CT** | 13.5%/min | 12%/min (LMS 100) |
| **Hydro** | 22.3%/min | |
| **Steam** | 3.1%/min | |

[15] Energy-limited units include hydro plants, which limit their production based on the amount of water they want to keep in the reservoir behind the dam, and dispatchable units that have a cap on energy production based on fuel limitations or pollution production limitations (i.e. limited NOx permits). In the 33% RPS analysis the CAISO allows most hydro to be dispatched such that its dispatch minimizes system costs while meeting weekly energy limits but the rest of the hydro is run-of-river hydro that is not allowed in the model to change its historic hourly dispatch from 2005 (assuming essentially zero flexibility for the run-of-river hydro which makes up less than 20% of the total hydro generation) (See CAISO 2010 pg 77). It is possible that even run-of-river hydro could provide some flexibility in the down direction by spilling water. If this flexibility could avoid the need for new flexible capacity it might be economic to spill a small quantity of run-of-river hydro. CAISO could consider allowing run-of-river to provide regulation and load following down by spilling water if the PLEXOS model finds that spilling is an economic option. Nonetheless, this issue may not have a significant impact given that the majority of hydro is treated as a flexible resource in the modeling by the CAISO.

[16] The CAISO does not account for limitations in the flexibility of CCGT's due to multi-stage configurations. This limitation will tend to understate the need for additional flexibility, but the magnitude of the impact is not clear. Most renewable integration studies that use production cost models like PLEXOS similarly do not account for multi-stage CCGT's. Relatively little research is available on this topic (see e.g. Troy and O'Malley 2010).

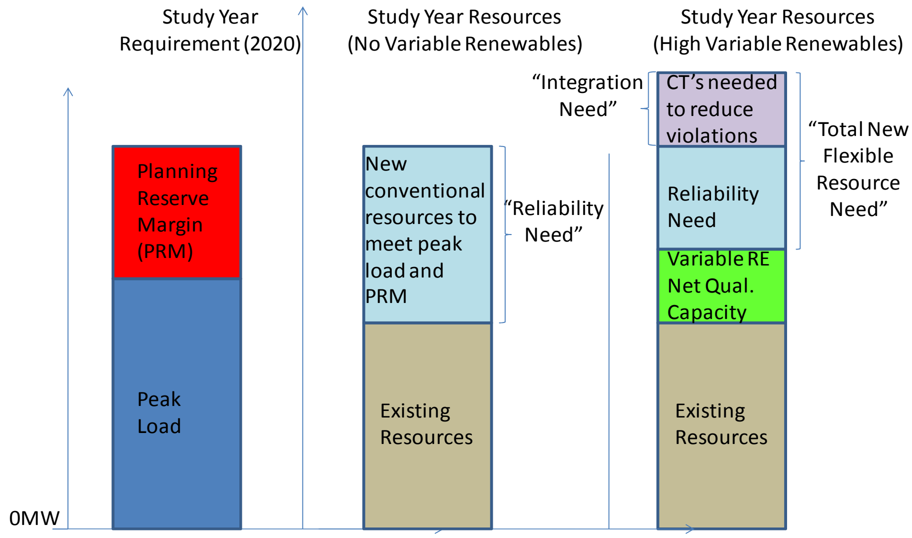


**Figure 4. CAISO approach to evaluating the study year.**

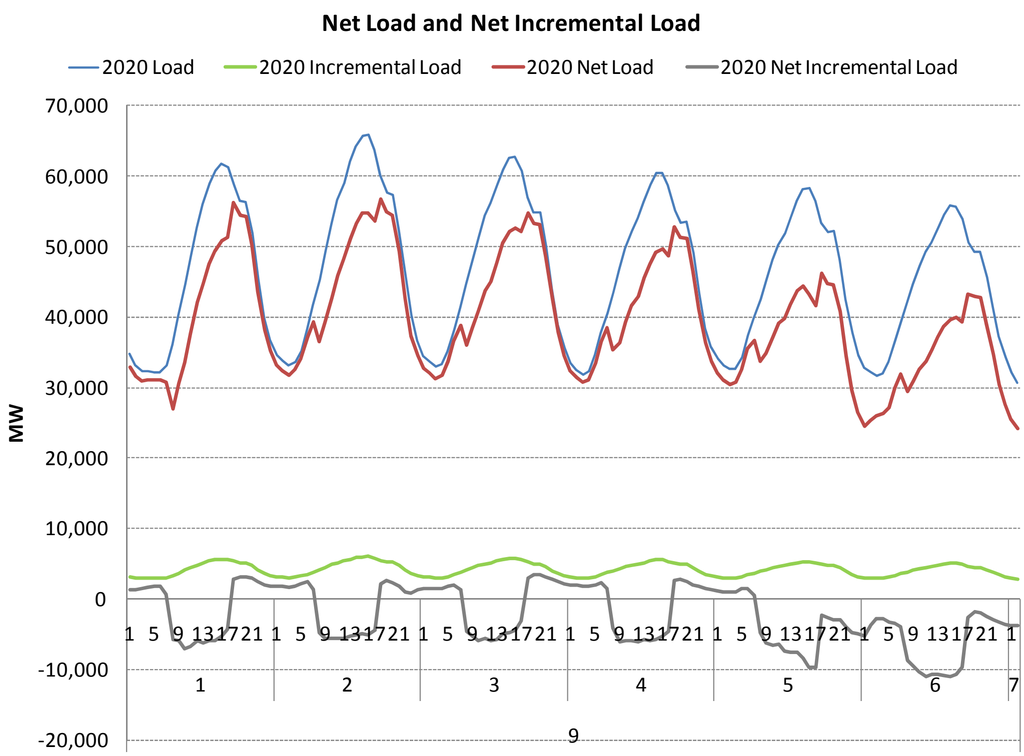


**Figure 5. Example of one September week of hourly total load and net load in 2020 (used in CAISO analysis) relative to the incremental load and net incremental load from 2008 to 2020 (used in RIM).**

The CAISO simulates the net load and increased operating flexibility service requirements in the detailed hourly production cost model. In hours where the 2020 system that is built to meet the study year peak load and planning reserve margin cannot satisfy the operating flexibility service requirements while simultaneously meeting the net load, the model indicates a violation. CAISO then adds new combustion turbines (CTs) to the system until the violations in *all* hours are mitigated (Figure 4). These violations could potentially occur because of insufficient conventional nameplate capacity, insufficient ramping capability, or too lengthy start-up times. The CTs added to mitigate violations are thus considered to represent resources built for *"integration need"* since they were not otherwise needed to meet the initial target planning reserve margin and peak load. The "*total new flexible resource need"* is the total amount of new conventional capacity that is added in 2020 ("*reliability need*" plus "*integration need*") on top of the existing resources and the NQC of the variable renewables. The "*integration costs*" of a particular portfolio are based only on the fixed cost of the CTs added on top of the reliability need (*the integration need*) plus a variable integration cost metric the CAISO has proposed to estimate the variable production cost portion of the integration costs. The variable production cost portion of the integration costs in the CAISO model is not yet well defined, but it appears to capture the difference between the avoided production costs assuming that the variable renewable portfolio in question did not increase the operating flexibility service requirements versus the actual avoided production costs calculated if (as simulated), the renewable portfolio did require increased operating flexibility service requirements.

Again, it is important to note that the flexible conventional resources required in the study year are not solely due to the renewables-driven increased variability and uncertainty characterized in Step 1. The separation of the total flexible resource need into the "reliability needs" and the "integration needs" implies that the resources that are labeled as integration needs are somehow a result of the increased variability and uncertainty that is characterized in the Step 1 process. This is not necessarily the case and may be a source of confusion in understanding the results of the studies and comparisons across different renewable portfolios. Resources that are attributed to "integration need" are due to any factor that could lead to a violation in the model (indicating that the available resources could not meet the energy and reserve target requirements in that particular hour) when starting with only the resources needed to meet the peak load and planning reserve margin net of the capacity contribution of the variable renewables. Thus, the integration needs may be a result of increased hour-to-hour ramps due to variable generation additions which are present in the production cost simulation even without the additional operating flexibility service requirements identified in Step 1 (applies to the CAISO analysis) or even due to discrepancies between the actual ability of variable renewable generation to serve loads at high penetration and the methodology used to assign a capacity credit to those renewables based on their calculated NQC[17] (applies to both the CAISO and RIM analysis). This latter issue is more clearly outlined in Appendix A. Thus, the main caveat is that new flexible resources that are attributed to "integration need" and the resulting "integration cost"

[17] In other words, the capacity credit "assigned" to wind and solar resources using the net qualifying capacity methodology is based only on variable renewable production during a particular window of the year that corresponds to current peak load periods. This methodology may be inconsistent with their actual

calculated in Step 2 of the California studies may be driven in part by factors other than the increased variability and uncertainty characterized in Step 1 and used to determine the operating flexibility service requirements for Step 2.

*2.2.2 PG&E RIM Approach*

Similar to the CAISO approach, the RIM model separates new flexible conventional generation into resources built for "reliability need" and resources built for "integration need". Unlike the CAISO, however, the RIM model does not directly account for the operational capabilities and constraints of the existing units to meet the 2020 total net load and operational flexibility service requirements. Instead of determining the actual flexibility of the different units used to meet the load and operational flexibility service requirements in 2008 and then modeling those unit flexibilities explicitly in 2020, RIM attempts to capture flexibility constraints on existing units by assuming that the units that are used to meet the load and operational flexibility service requirements in 2008 cannot increase their energy output or provision of operating flexibility services from 2008 levels in any particular hour (or whatever base year the RIM user chooses to start with: the choice of 2008 in the RIM model may be adjusted).[18] This assumed limited flexibility of the existing fleet is modeled in RIM by subtracting the 2008 hourly loads from the 2020 hourly loads and focusing only on the new capacity needed to meet the hourly *incremental* load between 2020 and 2008 (Figure 3).

ability to reduce the peak hourly net load, particularly for solar at high penetration as described in Appendix A.

[18] RIM does allow units used to meet the load in 2008 to *decrease* their hourly output from 2008 without any restrictions.

This focus on the incremental load is a significant departure from the analysis framework used by the CAISO and results in implicitly assuming severely limited flexibility of the existing system. In further discussion with PG&E, they explain that this focus on only the *incremental* load was a methodological choice that was selected in order to represent the potential energy and operating flexibility service limits and constraints of units that were used to meet the 2008 load. PG&E explained that this assumption is necessary to approximate the limitations arising from the more detailed modeling of operational constraints in hourly production cost models like PLEXOS.

Another way to understand the logic of the RIM model is that it checks *each hour* of the year in 2020 to see if (1) units built since 2008 to meet the planning reserve margin (the reliability need) plus (2) production from new variable renewables can meet the hourly incremental load growth (since 2008) and additional operating flexibility service requirements. It *does not* evaluate whether units used in 2008 can change their dispatch from 2008 (i.e. increase output or operating flexibility services) in order to meet the hourly incremental load growth and additional operating flexibility service requirements. If the units built to meet the planning reserve margin plus the new variable renewables cannot meet the incremental hourly load and operating flexibility service requirements in any hour of 2020 then RIM will require new CCGTs and CTs. (These new CT's and CCGT's are assumed to be perfectly flexible, such that their full nameplate capacity is assumed to be available for providing energy and operating flexibility services in any hour, in contrast to the static, inflexible energy and operating flexibility services provision level assumed for units used to meet load in 2008).

Whereas CAISO uses the estimated generating capabilities of individual units to identify hours with violations, RIM only compares the peak net incremental load and operating flexibility service requirements to the capacity of conventional plants that would be added between 2008 and 2020 as "reliability need". If the peak net incremental load and operating flexibility service requirements exceeds the reliability need then additional capacity is added to the system as *"integration need"*. The fixed costs of these new units are attributed to the fixed integration costs of the new renewable resources.

The authors found that the assumption in RIM that units cannot increase their energy and operating flexibility services from the base year leads RIM report higher integration costs for solar profiles than for wind profiles. To explain this we ignore for the moment the impact of variable generation on the operational flexibility service requirements by setting the variability and uncertainty parameters for all variable renewables to zero. We found that due to the high correlation of peak loads and solar generation, increasing solar penetration up to about 12 GW of solar decreases the peak hourly net load by about 60-70% of the nameplate capacity of solar (see Appendix A and B for more detail). The high NQC of solar reflects this contribution of solar to meeting peak loads. The framework used by RIM, however, only focuses on the ability of solar to decrease the peak hourly net incremental load (see Figure 5). Increasing solar penetration slightly above the existing amount (0.5 GW) decreases the peak hourly net incremental load by less than 8%. Adding high levels of solar has increasingly little impact in reducing the hourly incremental net load (i.e. adding more solar reduces the peak hourly net incremental load by 0% of the nameplate capacity of solar even at relatively low solar penetrations). RIM therefore decreases units built in the study year for reliability need due to the high NQC of solar, but then requires additional new flexible resources to be built to meet off-peak load growth in low-light or dark hours. These new resources built to meet off-peak load growth are attributed to integration need. In contrast, if RIM were to allow existing units in the base year to meet incremental load growth during off-peak hours (by more appropriately accounting for the flexibility of the existing units) then the actual reduction in peak net load from solar would better match the NQC assigned to solar. For solar penetrations up to about 12 GW, the additional new flexible resources that are built by RIM would most likely not need to be built if the existing resources were assumed to be more flexible.

For a low penetration portfolio consisting of 5-8 GW of solar and existing wind levels (~3-6% penetration of variable renewables), the conservative assumption of limited flexibility of the existing system in RIM leads to the addition of 3-6 GW of conventional capacity for "integration need". This results in a $46/MWh integration cost for a low penetration portfolio of mostly solar (all of the integration cost is due to the fixed costs of the CT's added for integration need) even when the portfolio is assumed to have no within-hour variability and be perfectly forecastable. These "integration costs" would largely disappear at that level of solar deployment if RIM accounted for the flexibility of the existing system.

Similarly, the high integration costs ($20.2/MWh) when the RIM model is used[19] with the reference portfolio of resources to meet the California 33% RPS (which includes about 12 GW of solar and 8 GW of wind) and all of the required operating flexibility service requirements from Step 1 are largely due to this treatment of solar in RIM. Even after setting all of the renewable resource variability and uncertainty parameters to zero (i.e. a perfectly known resource on a day-ahead basis that is constant within the hour) the integration cost remains $13/MWh[20] (all due to building 4 GW of new conventional capacity for integration need). The authors draw attention to this limitation of the RIM model because it is a methodological choice that cannot be altered in the normal use of RIM.[21]

An alternative methodology would be to assume units that were used to meet the load in 2008 are also perfectly flexible. This could be done by simply using the total load in 2020 instead of the incremental load in the RIM model. PG&E argued that simply using the total load in 2020 (rather than the incremental load) assumes too much flexibility in the way that units that are used to meet the load in 2008 can operate. The authors, however, are of the opinion that the methodological assumption in RIM that units used to meet the load in 2008 are so inflexible is a very conservative, if not incorrect, method for modeling the integration impact of variable renewables. Energy-limited resources, for example, could find it most profitable to decrease their output during times when the net incremental load is negative so that they could proportionally increase their output during

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[19] Using the solar adjustment model in RIM

[20] Note that the reason why the integration cost for a the 33% reference case is less than the integration cost for the existing wind and 5-8 GW of solar is that the denominator of the integration cost calculation (total MWh/yr of variable renewable generation) is much larger in the 33% reference case and the total amount of integration need (which drives the numerator of the integration cost calculation) is similar between the two cases.

[21] It can however be altered by changing specific formulas and references within the Excel spreadsheet to use the total load instead of the incremental load. Dramatically different integration costs are estimated assuming that all units used to meet load in 2008 are perfectly flexible (i.e. use the total load) versus assuming that all units used to meet load in 2008 cannot increase their dispatch from 2008 (i.e. use the incremental load). The authors encourage revisions to RIM to develop a different method for accounting

times when the net incremental load was positive (and the energy-limited resource was previously below its power capacity limit). Such profitable re-dispatch by energy-limited resources is captured in a production cost model like PLEXOS that explicitly models constraints on energy-limited units like hydro or conventional units with limited pollution permits.

There are a number of less dramatic differences between the RIM and CAISO model. With respect to the production cost impact of adding variable renewables, RIM uses simple approximations to estimate the increased production costs associated with additional operating flexibility service requirements. These approximations include generic estimates of start-up costs, part-load efficiency penalties, and higher costs of increasing reserves during the morning load pickup. These simplifications are transparent and easy to understand in RIM, but they do not necessarily capture the complex dispatch and commitment decisions that are made in the CAISO/PLEXOS model to estimate the changes in production costs due to the same factors.

### *2.3 Similarities between the CAISO and RIM studies*

The Step 1 process of characterizing the variability and uncertainty of the net load is largely similar between the CAISO analysis and the RIM model. The CAISO approach is largely based on methods that were developed by PNNL and have been used in past studies by CAISO and BPA (CAISO 2007, Makarov et al. 2009). The approach has been published in peer reviewed literature. One important note is that these earlier

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for any flexibility limits on existing units that does not simply assume that units built before 2008 cannot applications of this approach may have overstated the hour-ahead forecast error of variable generation by not taking into account the impact of geographic diversity on smoothing hour-ahead forecast errors. CAISO should ensure that their current method accounts for geographic diversity in hour-ahead forecast errors since the increase in operating flexibility service requirements is largely driven by hour-ahead forecast errors.

The RIM model uses a very similar framework to the original PNNL approach, but simplifies the calculations in order to directly estimate the variance of the net-load without relying on a Monte-Carlo simulation. RIM similarly should incorporate geographic diversity into their methodology for estimating hour-ahead forecast errors for wind and solar.

There are a few similarities in the Step 2 process for estimating the integration costs and new integration capacity needs between the two models. Both RIM and CAISO treat regulation and load following as reserve products that need to be met by resources other than those used to meet the hourly net load (in the case of CAISO) and hourly net incremental load (in the case of RIM). Both studies also start with generation capacity that is sufficient to meet the peak load and planning reserve margin net of the NQC of the renewable resources (the reliability need). They then both add new generation above the reliability need in order to ensure that the actual hourly net load (CAISO) and net incremental load (RIM) and reserve targets can be met in all hours of the year.

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increase their output in 2020.

### *2.4 Major simplifications in the RIM tool*

The key difference is that CAISO uses an hourly production cost model with detailed representation of individual unit constraints to determine (1) how units will be operated differently in high variable generation futures (2) when the system cannot meet the net load and operating flexibility services and (3) the change in variable production costs with the additional variable generation. RIM, on the other hand, reduces the estimation of the need for new integration resources to a comparison of the nameplate capacity of the generation added for the reliability need to the peak net incremental load plus operating flexibility service requirements.

This difference in approaches can lead to different reasons for adding new integration capacity between the two studies. Take a situation, for example, where the highest peak net load plus operating flexibility service requirements is 70 GW on a summer day (Aug 5). The most severe hour-to-hour ramp up in the net-load (~9 GW) occurs on a spring evening (March 27) where the net load plus operating flexibility service requirements is only 40 GW. The PLEXOS model will verify if sufficient flexibility exists in all online generators so that at their maximum ramp rate in the up direction they would be able to meet the 40 GW target net load while simultaneously meeting the operating flexibility service requirements and contingency reserves. The CAISO approach checks for these conditions and if it is not feasible to satisfy all of these targets (i.e. violations occur), the CAISO adds CTs with high ramp rates and quick start-up times until the 40 GW target net load can be met during the high ramp event while simultaneously meeting all of the operating flexibility service requirements. Any new CTs that might have to be added to avoid violating net load and operating flexibility service requirements would be considered in the CAISO study to be new integration resources. The CAISO checks to verify that the system can manage these types of events across all hours of the year. The RIM model, however, is unable to check whether sufficient online ramping capacity exists during that spring event. Instead RIM only focuses on the peak net incremental load and operating flexibility service requirements without considering ramping capabilities and start-up times for generators to provide the needed services.

In addition to the concerns about the assumption in RIM that units that are used to meet the load in 2008 cannot increase their provision of energy and operating flexibility services from their 2008 hourly levels, a major limitation of the RIM model is that it does not help to evaluate if the new capacity that is added for integration need is in fact sufficiently flexible. In other words, RIM does not illuminate whether it is better to pay more per unit of nameplate capacity for a unit that has higher ramp rates and/or shorter start-up times rather than pay less per unit of nameplate capacity for a less flexible unit. Instead, the new CTs and CCGTs added for integration needs are assumed to both be perfectly flexible and RIM only decides which conventional technology to pick based on tradeoffs between fixed costs and variable production costs. RIM thus only focuses on ensuring sufficient nameplate capacity of conventional generation without carefully evaluating the detailed flexibility constraints of the existing and planned conventional generation. The PLEXOS model used by the CAISO could be used to evaluate the relative merits of adding a lower cost but less flexible unit versus a higher cost but more flexible unit to deal with the violations that arise in the CAISO model. Such a sensitivity study could be used by the CPUC and other stakeholders to weigh various options for meeting the flexible resource need.

## 3. Comparison of the California Studies to Other Integration Studies

A wide body of research and experience with wind integration is available from the U.S. and international sources. Several studies in the U.S. have sought to quantify the integration costs associated with the addition of large quantities of wind energy – many of these U.S. studies are cataloged by Wiser and Bolinger (2010) and many of the international studies are described and compared in detail by Holttinen et al. (2009). The impacts of solar on the need for additional regulation, load following, and day-ahead commitment is comparatively much less understood.

### *3.1 Overview of Wind Integration Cost Literature*

Broadly speaking, a number of significant wind energy integration studies in Europe and the U.S. have concluded that accommodating wind electricity penetrations of up to (and in a limited number of cases, exceeding) 20% is *technically* feasible, but not without challenges (Gross et al., 2007; Smith et al., 2007; Holttinen et al., 2009; Milligan et al., 2009). With respect to Step 1, the estimated increase in operating flexibility service requirements in eight studies summarized by Holttinen et al. (2009) has a range of 1-15% of installed wind power capacity at 10% wind electricity penetration, and 4-18% of installed wind power capacity at 20% wind electricity penetration.

The increased operating flexibility service requirements in the Step 1 analysis of the 33% cases from the CAISO and RIM model fall within the range of requirements reported by Holttinen et al. (2009). The CAISO 33% RPS case with improved forecast errors leads to peak summer load following and regulation needs that are approximately 7% of the nameplate capacity of the variable renewables.[22] The RIM regulation, load following, and day-ahead forecast error requirements are about 10% of the nameplate capacity of the variable renewables.[23] Similar to the assumptions in RIM, those studies reviewed in Holttinen et al. (2009) that predict a need for higher levels of operating flexibility service requirements generally assume that day-ahead uncertainty and/or multi-hour variability of wind power output is addressed by system operators increasing the amount of generation capacity held in reserve for day-ahead forecast errors. In contrast, markets that allow intra-day trading provide additional opportunities to balance supply and demand within the day, reducing the reliance on more-expensive reserves (Weber, 2010). The CAISO integrated forward market (IFM) is a day-ahead market, but market participants are currently allowed to alter schedules within the day such that incorrect day-ahead forecasts can be managed through intra-day trading rather than by CAISO-held reserves. This indicates that the higher end of the operating flexibility service requirements identified by Holttinen et al. (2009) and the RIM assumption that all day-ahead forecast errors are met with increased reserves are potentially overly conservative in light of the intra-day balancing opportunities offered in the CAISO hour-ahead scheduling process. Just for clarification, the structure of the CAISO market indicates that day-ahead forecast errors do not need to be covered by resources that are kept in

[22] For the CAISO, the nameplate capacity of the incremental variable renewables added from 2009 to the 33% reference case was about 18 GW (CAISO slide 27 from August 24-25, 2010 presentation to CPUC). The total load following and regulation peak summer need is about 4.4 GW in the All Gas Case and is about 6 GW in the 33% Ref Case (CAISO slide 42 from October 22, 2010 presentation to CPUC). The amount of regulation and load following reserves added for variable renewables is therefore approximately 7% of the nameplate capacity of the variable renewables.

[23] For RIM, the nameplate capacity of the incremental variable renewables added from 2009 to the 33% reference case was about 20 GW. The total day-ahead forecast error, load following, and regulation peak summer need is about 7.7 GW if only existing variable renewables are included and is about 9.4 GW in the 33% Ref Case. The amount of regulation, load following, and day-ahead forecast error reserves added in

reserve by the CAISO, but the impact of day-ahead forecast errors on the costs associated with unit-commitment decisions made based on incorrect forecasts is still an important consideration.

Even with the wide range of assumptions used in the studies reviewed by Holttinen et al. (2009), they find that, in general, wind electricity penetrations of up to 20% can be accommodated with increased system operating costs of roughly US$1.4–5.6/MWh of wind energy generated. Similar results are found by Gross et al. (2007), Smith et al. (2007), and Milligan et al. (2009). The U.S. integration studies cataloged by Wiser and Bolinger (2010) report integration costs that are generally lower than about $10/MWh. The considerably higher integration costs reported in the 33% Ref. Case from the RIM model ($20/MWh) are surprisingly greater than the range of integration costs reported in the literature even though the increased operating flexibility service requirements are not out of line with the values estimated in the literature. This discrepancy is likely due to the assumption that units cannot increase their output from the dispatch in the base year and RIM having resources held in reserve for events that are not physically feasible (i.e. the earlier example of RIM holding reserves for a 16% drop in wind during hours when wind is producing at only at 10% of nameplate capacity). These issues warrant further detailed investigation of the differences between the California studies and other studies in the literature.

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RIM for variable renewables is therefore approximately 10% of the nameplate capacity of the variable renewables.

Many of the recommendations of the U.S. and international wind integration studies follow similar themes. The studies indicate that using state-of-the-art wind forecasts is essential to more economically and reliably integrating wind energy into power markets. Similarly, integration of large amounts of wind depends on the ability to access the flexibility of conventional generators. Balancing wind energy over a large area reduces the need to change the dispatch of generators and can reduce integration costs. Institutional limitations on accessing flexibility of conventional generators (e.g. lack of market signals to indicate the value of changing the dispatch of a conventional plant) and balancing of variability and uncertainty (e.g. small individual balancing areas with hourly schedules between balancing areas) may present significant barriers if not addressed. One important finding from past integration studies is that operating rules may prevent the system operator from accessing flexible resources that may otherwise be available. If these rules cannot be changed when high penetrations of renewable are added to the system, that may drive the need for additional physical resources that would otherwise be unnecessary. These steps (improve forecasting, create mechanisms/adjust institutions to access flexibility in conventional generation, and broadly balance variability and uncertainty) are seen as the "easy" integration steps in that they require modest investments in equipment or services but yield relatively large benefits. The institutional issues with implementing such reforms, however, are not necessarily "easy" and would require significant evaluation, coordination, and support from stakeholders.[24] The

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[24] Several initiatives are underway or are being evaluated to implement some of these reforms. The Variable Generation Subcommittee (VGS) at the WECC is evaluating the benefits of balancing area consolidation in the West or 10-min instead of 60-min scheduling between balancing areas. Several utilities in the West are participating in intra-hour scheduling pilots through the Joint Initiatives (a set of initiatives organized by WestConnect, Northern Tier Transmission Group, and Columbia Grid). FERC proposed that all transmission providers allow variable generation to use 15-minute scheduling instead of hourly scheduling in its recent NOPR (FERC, 2010). Successful implementation of many of these reforms

importance of the lessons learned from earlier studies is that many of the potential solutions to integration challenges reflect institutional changes as an alternative to solutions that require building new conventional capacity. These options should be evaluated, through targeted sensitivity studies, to determine if institutional changes can reduce the "integration need" being found in the California studies.

Even with improved forecasting, broad balancing, and mechanisms to access flexibility in existing generation, integration of significant amounts of additional variable generation may likely require additional flexibility. Additional recommendations from the wind integration literature focus on increasing the flexibility of the generation that is added. New generation with shorter start-up times, faster ramp rates, and lower minimum generation limits will increase the reliability of systems that have significant wind penetration. Demand response and bulk energy storage (particularly from pumped hydro facilities) are also seen as ways to help manage the increased demand for flexibility, but the overall technical feasibility and economic merit of these resources are much less understood compared to solutions based on improving the conventional power system.

### *3.2 Examples of similarities between the California studies and other U.S. wind integration studies*

With respect to Step 1, a few U.S. studies include the hour-ahead uncertainty and sub-hourly variability in estimating the magnitude of the load following with increased wind penetration. BPA (2009), for example, evaluated a 2-hour, 1-hour, and 30 min

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may reduce the integration capacity need and integration costs in California by enabling access to surplus flexibility outside of California or broader balancing of variable renewables.

persistence forecast as part of the load following requirement for wind in the Pacific Northwest.[25] EnerNex Corp. often includes an increased reserve requirement based on a 1-hour persistence forecast. Most U.S. studies include estimates of the increase in regulation reserves due to wind based on the variability of wind (but do not include the 5-min forecast component used by CAISO and RIM).

Previous integration studies primarily focus on the integration impacts of renewable energy using the total net load in a future year. No study that the authors are aware of ever used the assumption in RIM that all existing generation cannot increase its generation from a base year (i.e. no studies focus only on the net incremental load) in order to estimate integration impacts. Furthermore, most of the U.S. integration studies conducted by EnerNex Corp. and GE, two primary authors of most U.S. integration studies, use production cost models with detailed representation of individual unit commitment and dispatch similar to the PLEXOS model used in the CAISO study.

Several U.S. studies[26] simultaneously require load following and regulation reserve requirements to be met at the same time as the net load in a manner similar to the way the load following and reserves are met simultaneously to the net load in the CAISO analysis. A number of more recent U.S. studies[27] often also include estimates of the impact of the increased day-ahead forecast error in estimating the impact of adding wind

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[25] A 2-hour persistence forecast uses the hourly average wind two hours before the actual operating hour as the wind schedule for the operating hour. Similarly a 1-hour persistence forecast uses the hourly average wind for the hour preceding the operating hour.

[26] In particular the EnerNex Minnesota (2006), Enernex Eastern Wind Integration and Transmission Study (2010), and Enernex Nebraska (2010) study and the BPA (2009) study.

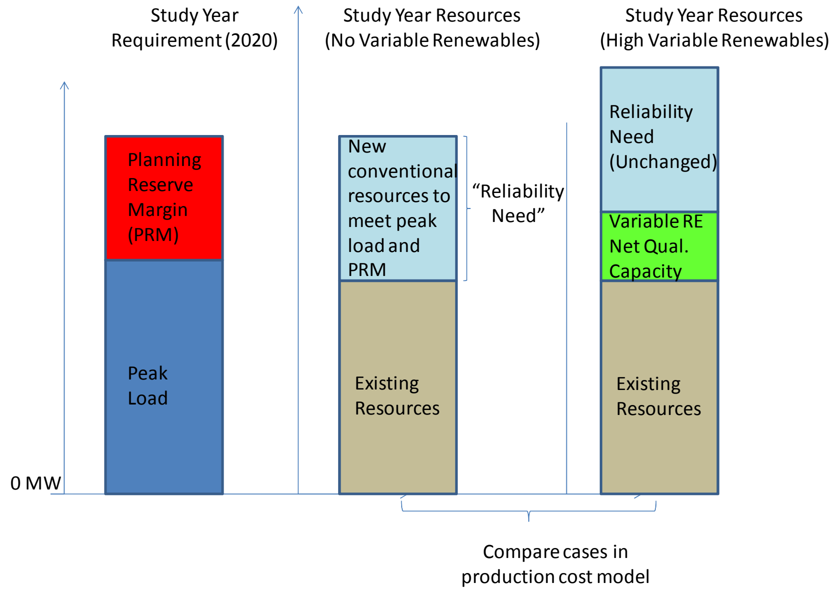
[27] Generally recent studies by GE and EnerNex Corp.

to the system. The studies that include day-ahead forecast errors only use the forecasts to commit units that take a long time to start. The studies then evaluate the variable costs associated with the imperfect forecasts and less-than-optimal commitment. A day-ahead forecast for significant wind production, for example, might lead to a CCGT not being committed. If the actual wind is lower than forecast, a CT that would not have otherwise been used is quickly started in the model to meet the load instead of the slow starting CCGT. The higher fuel cost of the CT relative to the CCGT is then captured in the model as part of the day-ahead integration cost. The RIM model, in contrast, uses the day-ahead forecast to estimate the magnitude of reserves that would need to be held outside of the energy market due to day-ahead forecast errors. The importance of this distinction is that RIM assumes that capacity cannot simultaneously be used to meet the actual net-load and correct for DA forecast errors.

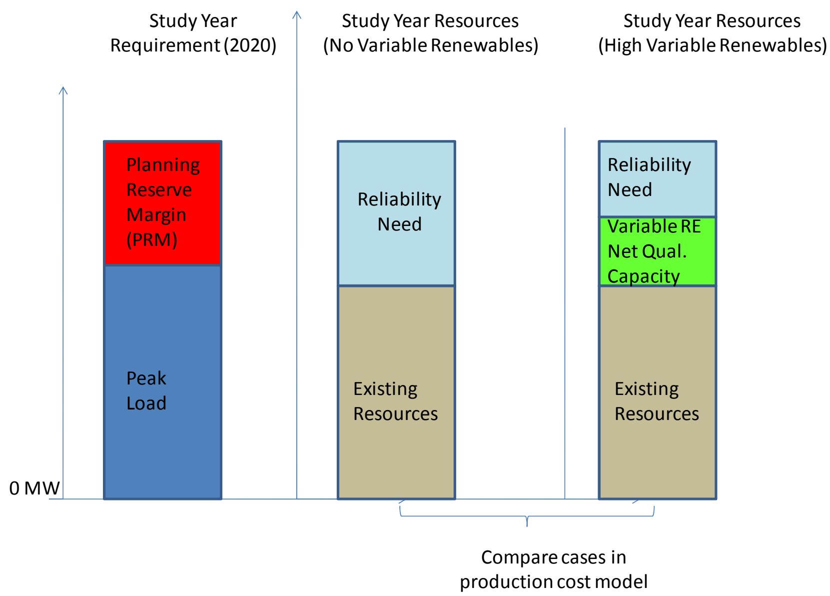
### *3.3 Examples of innovations in the California studies relative to other U.S. wind integration studies*

The California studies are different than some of the existing wind integration studies in ways that might be considered innovative. These particular differences between the California studies and the existing studies are improvements on past methodologies or are more appropriate to answering questions specific to the California market. The representation of the variability and uncertainty in the estimation of the regulation, load following, and day-ahead forecast error in the California studies, for example, is very well defined and specific to the California market. Past wind integration studies, for example, have not included the 5-min forecast error for regulation in the same way that it is included in the California studies to mimic the operation of the CAISO real-time market.

A major innovation in the California studies is the assumption that the system built in 2020 would be one that can meet the peak load and planning reserve margin *net of the NQC of the renewable resources.* Many past U.S. integration studies assume the system will be built to meet the peak load plus planning reserve margin. Those studies estimate the capacity contribution of wind but do not necessarily decrease the initial build-out of conventional generation in proportion to the capacity contribution of the variable renewables (Figure 6a). In a sense, many past integration studies have therefore reported integration costs based on the implicit assumption that the capacity credit of variable renewables is zero. The integration costs in those past integration studies may have been understated relative to integration costs if variable renewables were instead to be assumed to have a positive capacity credit that reduced the reliability need.




(a)




(b)

**Figure 6. Many integration studies start with a system that has sufficient resources to meet the peak load and planning reserve margin (middle bar of *a*). The results are compared to a case where significant new variable renewables are added to the same system (right bar of *a*). The innovation of the California studies is to start with a reduced amount of new conventional resources added in the study year according to the net qualifying capacity of the variable renewables (right bar of *b*).**

To understand the potential impact of this innovative approach, we highlight one sensitivity study in the Western Wind and Solar Integration Study (WWSIS) (GE 2010) that did assess a high variable renewables case where the conventional capacity was sufficient only to meet the peak load and planning reserve margin net of the capacity credit of the variable renewables (as in Figure 6b). The authors of the study initially evaluated a system with high wind and solar penetration assuming it would have sufficient conventional capacity to meet the peak load and planning reserve margin (like Figure 6a). They did find a small number of hours where the actual net load and operating reserve requirement could not be met (the model produced violations), but they show that these violations were generally due to incorrect day-ahead forecasts. Discounting the day-ahead variable renewable forecast reduced the number of hours with violations, but it then increased the amount of wind curtailment due to over-generation conditions. In the resource adequacy section of the report, the authors calculate a capacity credit of about 6.5 GW for the 35 GW of variable renewables added in the 30% wind and 5 % solar penetration case.[28] As a sensitivity case, 6.5 GW of conventional capacity was no longer added as part of the reliability need due to the contribution of the variable renewables and the production model was run again (like in Figure 6b). The production costs between the original case and the reduced capacity case were about the same, but the reduced capacity case led to an increase in the shortfall of contingency reserves or an increase in the violations. The shortfall (the quantity of shortfall – not necessarily the hours with a shortfall) was tripled in the reduced capacity case (like Figure 6b). The authors did not go back in and again discount the day-ahead forecast nor add CTs, like in the CAISO study, to then see what changes would be needed in order

[28] In contrast to the 70% exceedance method during peak load hours that is used to estimate the NQC in the California studies, the WWSIS used a full loss of load expectation analysis for each portfolio of renewable resources. The capacity credit estimated in the WWSIS therefore does not suffer from the complications of the inaccurate NQC method outlined in Appendix A.

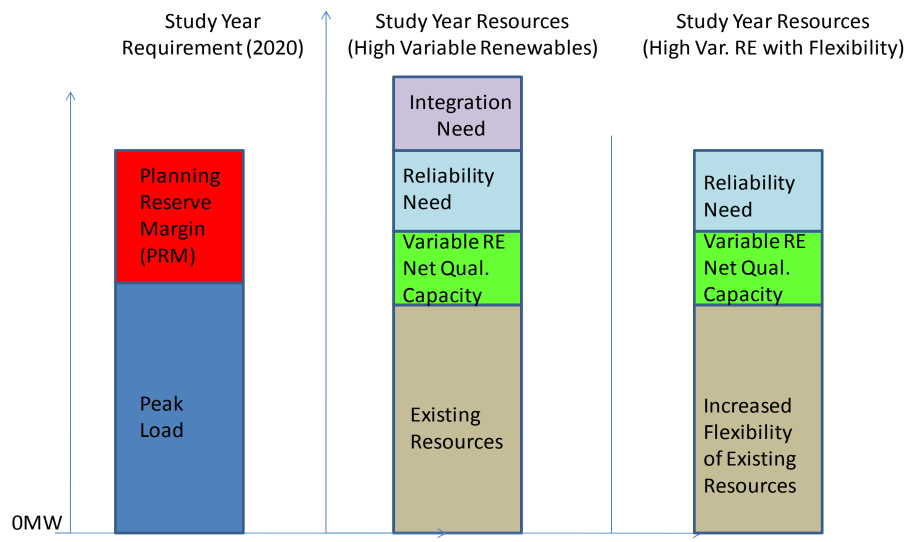
meet the peak net load plus the operating flexibility service requirements without shortfalls in reserves. The authors of the WWSIS do indicate that this is an area that deserves more research. The California studies, which start with systems that can only meet the peak load and planning reserve requirement net of the capacity credit of the variable renewables (like Figure 6b), are therefore advancing the understanding of integration impacts beyond the existing literature.

As described earlier, when the CAISO initially runs its 33% reference case like in Figure 6b it finds that the existing (and planned) resources[29] and the resources added for reliability need leads to hours in the production cost model with violations. They then add new flexible CT's to reduce the violations. These new CT's are attributed to "integration needs" and they make up the fixed cost component of integration costs (Figure 7a). Kirby and Milligan (2008) argue against the idea that adding wind to a system for use within that balancing area leads to additional capacity requirements (beyond adding capacity for the regulation requirement). Rather, adding wind increases the need for flexibility from the units that are built to meet the peak load and planning reserve margin. Although the analysis by Kirby and Milligan (2008) starts with the assumption that variable renewables are added to a system that can already meet the peak load and planning reserve margin (like Figure 6a), the key points from their analysis are still applicable to the California studies. The key point is that if adding variable renewables does not increase the planning reserve margin and peak load, then making existing units

[29] CAISO starts with the existing generation but then adds 9.4 GW of planned generation based on contracts that are already approved by the CPUC. Many of these planned resources are CCGT's. Simple upgrades or alterations to the plant design may enable more flexibility from these planned units than is modeled by the CAISO (see e.g. Heikkinene et al., 2008)

more flexible might be sufficient to reduce the violations observed in the CAISO analysis (and therefore reduce the integration capacity need) by (Figure 7a). Or alternatively, the units that are added for integration capacity need in the study year may contribute to the "reliability need" in future years with load growth and/or retirements of existing units (Figure 7b).

**(a)**




**(b)**

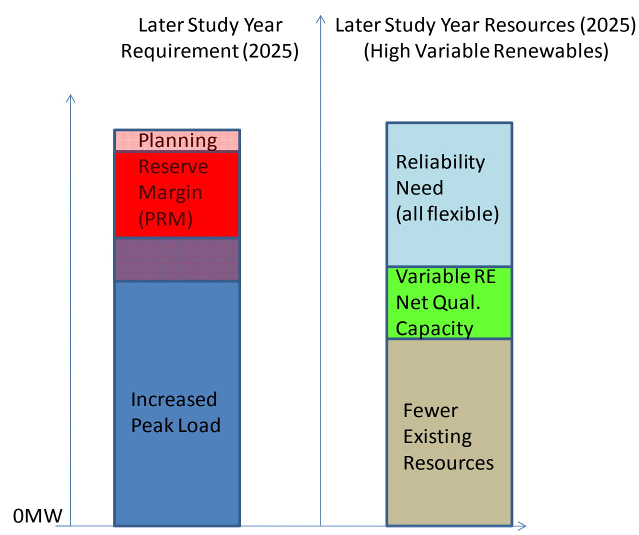



**Figure 7. CAISO finds violations when starting with the system in Figure 6b. They add additional CT's (called the integration capacity need) to the system until these violations disappear (middle bar in a). Analysis by Kirby and Milligan (2008) suggests that these CT's might not be needed if instead the flexibility of the existing (and planned) resources were increased (right bar in a). Alternatively, the new**

**CT's added for integration capacity need in 2020 could count toward the "reliability need" in a later study year with load growth or more planned retirements of existing inflexible units (right bar in b).**

Given the innovativeness of the approach used in the California studies, it is worthwhile to carefully understand the implications of the violations observed in the production cost model and potential alternative methods for dealing with the violations. CAISO can use a sensitivity study with increased flexibility of the existing and planned units and the 33% reference portfolio to evaluate the potential for increased flexibility of existing units to avoid the need for new flexible capacity (Figure 7a). CAISO can also examine a sensitivity study of increased load to 2025 levels, but the exact same resources as used in the 2020 case for the 33% reference case, to determine if units built for "integration need" not only add flexibility to the system but also enable it to meet increased future loads (Figure 7b). These sensitivity studies should be easy to implement and would aid in understanding the implications of the "integration need" found in the 33% reference case.

### *3.4 Examples of California studies not following innovative practices from other U.S. wind integration studies*

There are some trends in the U.S. integration studies that may be applicable to the California studies that were not included in the California studies. One trend, particularly in EnerNex studies, is to condition the hour-ahead forecast error on the amount of wind generation that is expected. High wind and low wind periods have relatively lower variability and uncertainty than periods where the wind speeds are moderate. The reason is that wind turbine power curves follow a cubic relationship to wind speed up to the rated wind speed of the turbine. A change in the wind speed from 7 to 9 m/s can lead to a very large change in wind output. A change from 1 to 3 m/s or from 13 to 15 m/s does not change the output of the wind turbine at all: it remains in the first case at zero output or in the second case at its rated wind power output for any wind speed above the rated wind speed (up to the cut-out wind speed). Recent wind integration studies[30] adjust the amount of operating flexibility service requirements according to the wind production, Figure 8. This can lead to an overall reduction in the wind integration costs since large amounts of load following up reserves are not needed when the wind output is already low, for example.

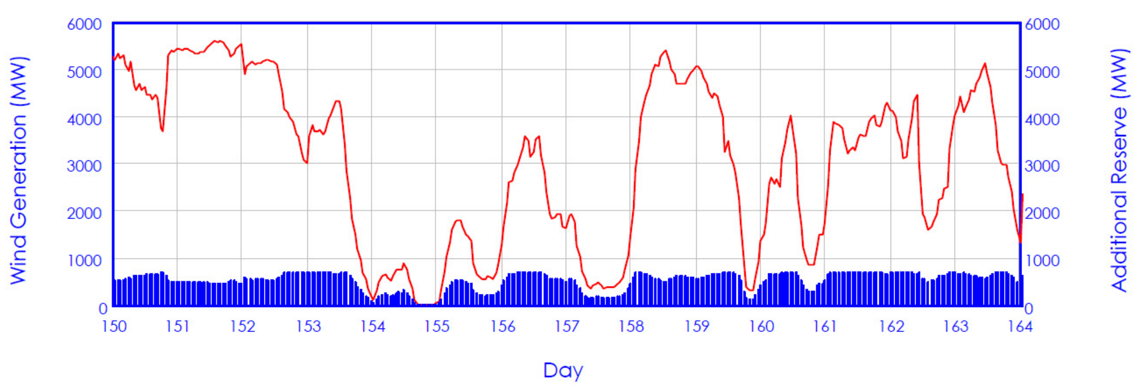



**Figure 8. Example of additional reserves due to hour-ahead forecast errors for wind (blue bars) that vary in the production cost model according to the level of expected wind generation (red line). Source: EnerNex Corp. (2006), Figure 30.**

Another common practice that is used in studies conducted by GE, but is not part of the California studies, is a detailed evaluation of the system during periods of high stress. The CAISO study adds CTs when the model indicates violations, but the CAISO has not evaluated in detail the condition of the system during those hours that apparently drive the need for more CTs. GE often conducts what they call Quasi-Steady State (QSS)

[30] See the EnerNex Minnesota (2006) and EnerNex EWITS (2010) studies for examples

analysis over a multiple hour period surrounding times of high stress (or periods with violations). During a QSS analysis GE uses 1-min time-series and the commitment and dispatch schedules from the hourly production model to verify the reliable operation of the system during those periods or to highlight changes that would need to occur in order to accommodate the periods of high stress. The WWSIS study includes a detailed evaluation of an October day with a very high day-ahead wind forecast error. They find that at points during the day the system will lack sufficient up and down flexibility from the conventional power system. They recommend pursuing options such as demand response to provide additional flexibility during these periods.[31] Such a detailed dive into the periods that are identified by the CAISO as periods with violations would help validate their modeling approach and identify the need and characteristics for additional flexible resources.

## 4. Major Caveats to Using Studies to Inform CPUC

The CPUC is primarily interested in understanding the adequacy of these two models in informing the integration cost of different renewable portfolios and the potential authorization to utilities to procure non-renewable resources required by 2020 to meet a 33% RPS. Based on this review of the models in the preceding text and the appendices, we find four issues that should be examined in more detail and several other issues that are important but can largely be dealt with through sensitivity studies relative to the reference cases (Table 2).

[31] GE did not evaluate the economic cost of a demand response program nor did they evaluate what program design would be required to obtain customer and regulatory approval for such a demand response program. More detailed evaluation of the necessary requirements of demand response programs to assist with integrating variable renewables is warranted.

The highest priority issue is the limited flexibility assumed for the units used in the base year when analyzing the study year in the RIM model. This limitation leads to an overstatement of the integration need, particularly for solar. Resolving this issue will require modifications to the RIM model to better account for the flexibility of the existing system. Dealing with the current assumption of the limited flexibility of the existing units will also require characterization of the flexibility of *both* existing and new units (i.e. in terms of ramp rates, minimum generation, and start-up time) in RIM.

**Table 2. Issues to consider in using California studies to inform CPUC process**

| Study | Issue | Priority | Steps Required to Resolve | Comments |
|---|---|---|---|---|
| **RIM** | Base year dispatchable resources cannot increase output or contribution to reserves in study year | High | Revision of Step 2 portion of model. Potentially requires large revision to model. | Severely impacts results for solar, some impact on wind. Leads to overstatement of "integration needs" |
| **RIM** | Incorporate flexibility characteristics and constraints of conventional resources into model | Medium | Inclusion of generator parameters related to flexibility (ramp rate, min-gen, start-up time) in evaluation of integration need. Potentially requires large revision to model. | Aside from assumption that base year resources cannot increase output in the study year, RIM does not characterize the flexibility of new or existing units. |
| **RIM and CAISO** | Ensure operating flexibility service requirements are held based on feasible forecasts | Medium | RIM - Revision of Step 1 methodology; CAISO – detailed examination of current methodology for converting Step 1 results into Step 2 inputs | RIM currently adds units to provide reserves for physically infeasible events. CAISO may do same when using maximum seasonal load following requirements in Step 2. |
| **CAISO** | Evaluate implications of day-ahead forecast errors (not currently modeled by | Medium | Detailed modeling of unit-commitment (Step 2) and day-ahead forecast errors (Step 1) may require significantly more data, revisions to model, and | Large day-ahead forecast errors may require commitment of long-start units that would otherwise not be (or remain) committed, and/or require |

| | | | | |
|---|---|---|---|---|
| | CAISO) | | additional processing time. Quick evaluation might be done with post-processing of results from existing model. | additional fast- or medium-start units in the system. |
| **RIM and CAISO** | Adequately incorporate benefit of geographic diversity in hour-ahead forecast error | Low | CAISO is investigating this issue and should continue to focus on it. Diversity-related refinements could also be applied to RIM. | Improved forecast errors appear to reflect expected errors for persistence forecast of geographically diverse resources, but detailed evaluation is warranted |
| **CAISO** | Evaluate options to increase access to existing flexibility or decrease forecast errors (Figure 7a) | Low | Develop and analyze additional sensitivity scenarios to evaluate relative to the reference case. | Reducing institutional barriers to accessing flexibility of units outside of CA, providing incentives to operate existing units in ways that are more flexible than currently operated, accessing flexibility of run-of-river hydro, and improving forecasts may all potentially substitute for new "integration need". |
| **CAISO** | Evaluate ability of units built in study year (2020) for "integration need" to contribute to "reliability need" in future years (e.g. 2025) (Figure 7b) | Low | Develop additional sensitivity scenarios to evaluate relative to the reference case. | If new units are needed to increase overall system flexibility, the same units may also help meet future load growth. Use system that addresses all violations in 2020 but increases the load to 2025 levels in sensitivity study to determine if the 2020 system is adequate to also meet increased loads |

Another important issue, particularly for modeling wind, is to ensure that operating flexibility service requirements that are being held in the model correspond to situations that are physically possible. The seasonal maximum approach applied in RIM can lead to situations where the operational flexibility service requirements in the up direction due to the potential over-forecast or ramp-down of wind exceed the hourly wind production level. As currently formulated, RIM's Step 1 approach seems to reasonably estimate the seasonal maximum operating flexibility service requirements for wind and solar. Requiring that this seasonal maximum operating flexibility service requirement be held in reserve for each hour of the season irrespective of the wind generation level, however, can overstate the integration need in Step 2. Fixing this will require a modification to the current RIM methodology. The CAISO should similarly evaluate the conditions that drive the violations in the PLEXOS model to ensure that violations are not caused by operating flexibility service requirements that are based on infeasible changes in wind or solar production.[32]

The last important issue is the impact of day-ahead forecast errors. Day ahead forecast errors can be large. Insufficient generation that can be ramped up or started in a quick enough time frame to accommodate the day ahead over-forecast errors of variable generation will lead to violations. Or conversely insufficient generation that can be decommitted or ramped down to accommodate day-ahead under-forecast errors of variable generation could lead to increased over-generation conditions and curtailment. The CAISO model does not currently address this, but at high penetration of variable renewables day-ahead forecast errors could potentially drive the need for increased flexibility, depending on the makeup of the generation fleet[33] with regard to start-times and ramp rates. Incorporating day-ahead forecast errors and unit-commitment into the

[32] The difference between the integration need found in the 33% reference case, where reserves were based on the seasonal variability and uncertainty, and the integration need found in the sensitivity case that used hourly maximums may be partially explained by this issue (CAISO Nov. 30 presentation to the CPUC, slide 69) . Detailed evaluation is warranted, but CAISO has the capability to incorporate these changes without modification to their model.

current PLEXOS model may take a substantial data collection and model revision effort. If day-ahead forecast errors cannot be dealt with in detail, the CAISO might be able to evaluate in general terms the potential impact of day-ahead forecast errors through post-processing of their existing model results.[34]

Finally, the remaining issues address the fact that many of the recommendations from the integration literature focus on improved forecasting and accessing the flexibility of the existing system. In light of past integration studies, our recommendation is for the CAISO to devote a significant amount of time exploring and explaining the results of their analysis to show how limited flexibility of the existing and planned conventional units contribute to integration challenges and what characteristics of new conventional units would be needed in order to mitigate those challenges in a system with high penetration of variable generation. These issues can be evaluated primarily through sensitivity studies around the reference case. These sensitivity studies will enable the CPUC and other stakeholders to better interpret the results of the California studies in terms of alternative options for addressing the integration need found in the reference case and the portion of the integration need that should be solely attributed to the variable renewables.

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[33] The generation fleet that can respond to day-ahead forecast errors includes any generation that could obtain transmission access into California within the operating day after it is realized that the day-ahead forecast is in fact inaccurate.

[34] From a reliability perspective, the post-processing could check to see if sufficient quick start units were available during times when large slower starting units are decommitted to accommodate the seasonal maximum day-ahead forecast errors. This would ignore the potential economic costs of substituting energy from a higher cost unit for a lower cost unit, but the operational costs of day-ahead forecast errors would require a detailed day-ahead unit-commitment model.

It is important to ensure that the hour ahead forecast errors used in the studies are carefully estimated to realistically represent aggregate output profiles for future portfolios of dispersed variable generators (Holttinen et al., (2009) and Lorenz et al. (2009) illustrate the reduction in forecast error with geographic diversity for wind and solar, respectively). If more precise assessments are not available, sensitivity studies can be used to show how sensitive the final integration need and cost results are to changes in estimates of forecast errors. And if the best estimates of future forecast errors for aggregated variable generators still show high forecast errors, then investment in improved forecasting might be evaluated as an alternative to adding new capacity to accommodate large forecast errors. It may be significantly less expensive to improve forecasting capabilities than it would be to build new conventional capacity to stand-by to balance large forecast errors.

## 5. Conclusions

The primary objective of this review is to help the CPUC determine if there are fundamental problems with using the results from the CAISO 33% renewable integration analysis and the PG&E Renewable Integration Model (RIM) in informing integration costs and needs across different variable renewable portfolios in the LTPP. In performing this review we compared the approaches used in the California studies to past studies in other parts of the U.S. and internationally. Although there are still many uncertainties around the best approaches and the resulting costs to integrating variable renewables, a consistent theme is that reliable and economic integration of variable renewables will require significant flexibility in the power system. Accounting for the full flexibility of the existing system, determining ways to increase the flexibility of existing plants, and determining the least cost options for new sources of flexibility should all be key parts of the analysis of a high variable renewable energy future. Most state-of-the-art integration studies use a production cost model, like PLEXOS, to account for the available flexibility of a system with high penetration of variable generation.

Though the RIM tool and the CAISO analysis have similarities (along with some important differences) in the methods used to estimate the operational flexibility service requirements across various variable renewable portfolios (Step 1 results), the operational flexibility service requirements alone are not necessarily sufficient to compare relative integration need and costs across portfolios. In order to compare the relative integration needs and cost, a Step 2 analysis that uses the Step 1 results as one of the inputs is required. The RIM tool, as it is currently formulated, implicitly only allows new units built to meet the planning reserve margin and peak load (the reliability need), new variable renewables, and if needed new CT's or CCGT's that are attributed to "integration need" to meet the hourly incremental load growth between the base year (i.e. 2008) and the study year (2020) in its Step 2 analysis. This methodological approach implies that the capability of the system used in 2008 to increase its provision of energy and operating flexibility services in 2020 is not accounted for in the RIM model. This is a conservative assumption that particularly impacts the assessment of solar and most likely explains why the integration costs for a 33% RPS far exceed the integration costs reported elsewhere in the literature. While PG&E raises valid concerns with assuming that all existing generation is perfectly flexible, their approach appears to be overly conservative. Without revising the RIM model or clear validation of this assumption, the results from the RIM are not going to be as useful for understanding the integration costs and need for the CPUC and other stakeholders versus results from a detailed production cost model that can account for the flexibility of the existing system.

The CAISO and RIM model are based on innovative approaches in which the conventional system in the study year (2020) initially only has enough capacity to meet the planning reserve margin and peak load *net of the qualifying capacity of the variable renewables.* The CAISO Step 2 analysis then uses PLEXOS to determine in each hour of the year if the system in 2020 will be sufficiently flexible to accommodate the variability and uncertainty associated with a 33% RPS. Because there are few other integration studies that have attempted to determine the best way to solve model violations due to insufficient resources to meet the net load and operating flexibility service requirements in each hour, the CAISO should carefully examine the origin and resolution of violations. Questions that should be addressed include: Were the operating flexibility service requirements in hours with violations based on realistic expectations of variability and forecast errors for those particular hours? Was the flexibility of the existing system fully utilized during the hours with violations? In particular, are new resources being added in the model due to institutional limitations on accessing the existing flexibility of the power system (i.e. limitations on which units can provide operating flexibility services)? And if new flexible units are added to mitigate violations, can the same units be used to meet future requirements for planning reserve margins (or future renewable resource additions) or will the capacity added as integration need in 2020 be solely used to integrate the variable renewables added in 2020? Clear answers to those questions will provide confidence in the integration costs and needs attributable to the variable renewables. Furthermore, detailed evaluation of the timing and system conditions during times when new integration need was added to the system to mitigate violations across a wide variety of variable renewable portfolios may indicate underlying relationships between the operational flexibility service requirements identified in Step 1 and the integration need and costs resulting from the Step 2 analysis. If underlying relationships are clearly identified and understood, these could potentially be used to predict how Step 2 results will change based on changes in the Step 1 results without running the full Step 2 analysis each time. Without the more detailed analysis to justify such a relationship, however, there is not sufficient analysis to relate Step 1 results to the integration need and costs without actually performing a Step 2 analysis.

Finally, based on the importance of hour-ahead forecast errors in the operating flexibility service requirements, significant attention should be given to estimating future forecast errors for portfolios of geographically diverse resources along with the costs to reducing forecast errors. Day-ahead forecast errors are not currently addressed in the CAISO analysis. The CAISO does not need to hold resources in reserve to meet day-ahead forecast errors, but it should evaluate the costs and feasibility, for example, of having to start CT's if insufficient slow starting units are committed day ahead. CAISO should, as it did in the 20% RPS analysis, evaluate the operational practices that will be required to ensure that the system can be operated reliably with day-ahead forecast errors with high levels of variable renewable energy.

## Appendix A. Reduction in Peak Net Load and NQC for Solar

This appendix focuses on interaction of hourly solar generation profiles and load profiles at increasing levels of penetration. It does not consider the within-hour variability and uncertainty – in all of these results the variability and uncertainty parameters have been set to zero for all variable renewables. The first section shows that the reduction in the peak hourly net load with increasing solar penetration tracks the expected reduction based on the NQC of solar for low to medium solar penetration levels (up to ~12 GW of solar). At greater solar penetration levels, however, more solar is not able to reduce the peak hourly net load (i.e. the highest hourly value of the load net of variable generation across all hours of the year). This is because high solar penetration shifts the peak hourly net load into the early night. At high solar penetrations the expected reduction in peak net load from the NQC of solar (which is calculated based on solar production during peak *load* periods) will begin to diverge from the actual reduction in the peak hourly net load. This issue can be resolved by revising the NQC methodology for scenarios with high solar penetrations (> 12 GW).

The second section then demonstrates that even though solar can reduce the peak hourly net load for penetrations up to about 12 GW, it only reduces the peak hourly net *incremental* load (the hourly load growth between the base year and the study year) for very low solar penetrations. Because the RIM methodology focuses on the resources needed to meet the peak net incremental load, and therefore implicitly assumes that the existing units from the base year cannot increase their output even in off-peak hours, RIM does not account for the peak net load reduction value of solar for penetration levels up to about 12 GW. The resulting mismatch between the expected reduction in peak net incremental load based on the NQC and the actual reduction in the peak hourly net incremental load leads to new flexible units being built in RIM. These units would most likely not have been needed, at least not in the same amounts, if the flexibility of the existing system were better accounted for. Because of the relatively low NQC of wind, this issue does not impact wind in the same way. The method used by RIM therefore differentially impacts solar relative to wind.

*Issue 1: NQC does not change with penetration, but ability of solar to decrease peak net loads decreases with high penetration of solar.*

The CAISO and RIM estimates of total flexible resources needed in 2020 are based on hourly variable generation and load profiles for a particular year. In each hour, the studies verify that sufficient generation will be available to meet load and operating flexibility service requirements. Both studies partition this total flexible resource need into the "reliability need" and the "integration need". The reliability need is the portion of the total flexible resources that are required to meet the peak load plus planning reserve margin less the net qualifying capacity (NQC) of the variable renewables. As CAISO describes in their Nov. 30th presentation to the CPUC (slide 85), for the same total flexible resources needed in a particular scenario, the attribution of the resources into "reliability need" and "integration need" therefore depends on the estimate of the NQC for the variable resources. If the NQC is estimated to be very high, then more of the total flexible resource need will be attributed to "integration need". If the NQC is estimated to be very low, then more of the flexible resource need will be attributed to "reliability need". The best and least confusing approach would ideally estimate the NQC in a meaningful way so that the "integration need" would be related to issues of generator flexibility and increased operational flexibility requirements while the "reliability need" would base based on expectations of the capability of conventional and variable generation to reliably meet demand. To explore this issue in more detail, we examine the hourly load and generation profiles and the operating flexibility service requirements for the load alone without consideration of the operating flexibility service requirements for the variable renewables.

*Using the Total Load (CAISO Approach)*

At issue is that the current NQC approach used by the CPUC focuses on variable generation during peak load periods. The underlying assumption is that if a variable generator is expected to consistently generate power during peak load periods it will contribute to meeting demand and some fraction of the variable generator can count toward the planning reserve margin. The problem is that as the penetration of variable generation increases, the period in which generation capacity is scarce will shift from periods of peak load to periods of peak net load. This is more obvious in the case of solar generation. Under the current NQC methodology solar generation receives a high NQC due to its high output during summer afternoon peak load periods. As the penetration of solar increases, however, there will be ample generation during summer afternoon peak load periods, but solar will not reduce the load during summer early evenings after the sun goes down. At high solar penetration levels, the high net load period will become the critical hour and increasing solar capacity will not reduce the summer evening load. This issue is clearly illustrated in Figure 9 which shows the total load plus operational flexibility requirements for the load minus the hourly generation from a renewable resource portfolio with increasing CSP.[35] The peak load occurs on the afternoon of July 24th. CSP

[35] The 0 % line includes no existing and no new variable renewable generation. The 1% line includes the existing variable renewables (~3GW wind and 0.5GW CSP) plus sufficient new variable renewables from the technology to equal 1% total variable renewables penetration. All non-zero lines therefore include the hourly generation from the existing wind and solar.

generates significant energy during this period which dramatically decreases the net load during the summer afternoon. After about 12 GW of CSP are installed (the 8% IR line), however, the critical hours shift to the early evening of July 24th. Adding additional CSP will continue to decrease the net load during the afternoon, but the CSP will not reduce the net load during the new critical period.

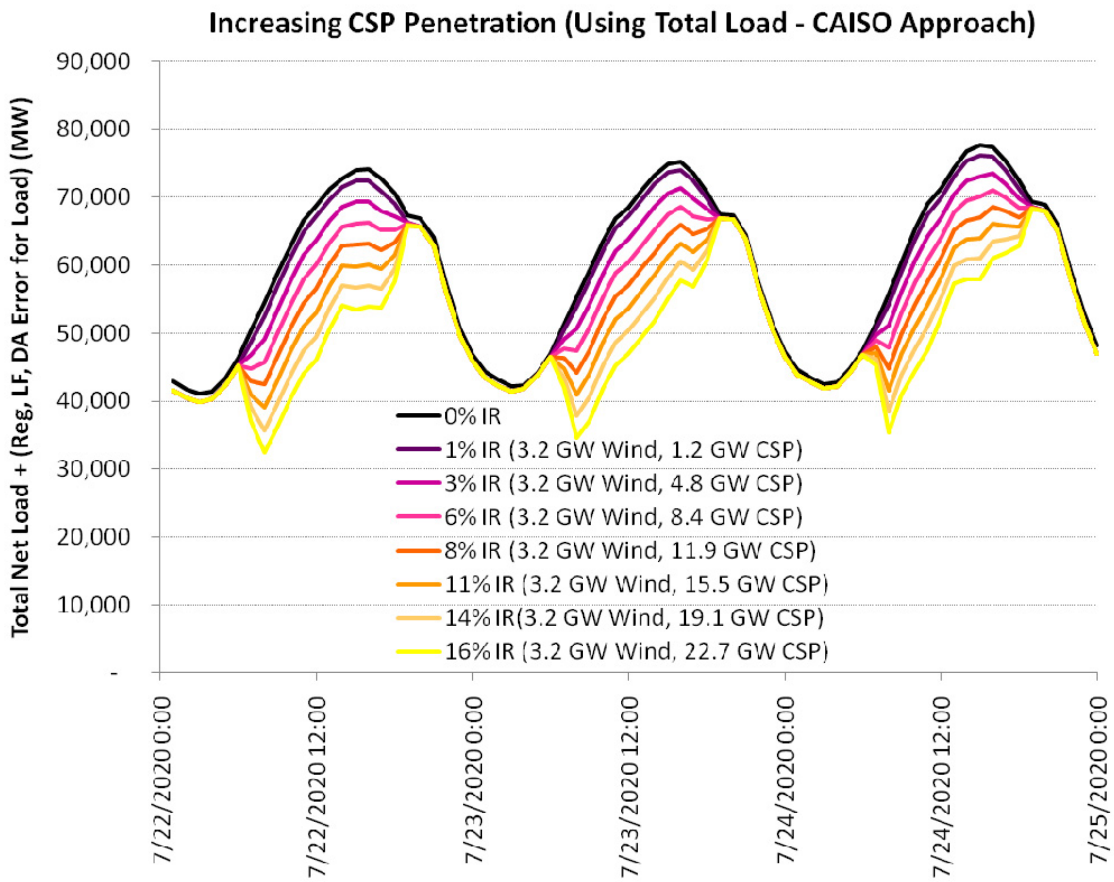


**Figure 9. Change in net load with increasing CSP penetration (assuming no within hour variability and forecast error for CSP).**

Therefore at high solar penetration levels, the current NQC methodology will continue to assign a high capacity credit to CSP even though additional CSP plants are no longer contributing to the reduction in net load during the new critical (highest net load) period.

This discrepancy between what is implied by the NQC methodology and what is actually measured in the reduction in the peak hourly net load is illustrated for each technology (PV, CSP, and New Wind) in Figure 10.

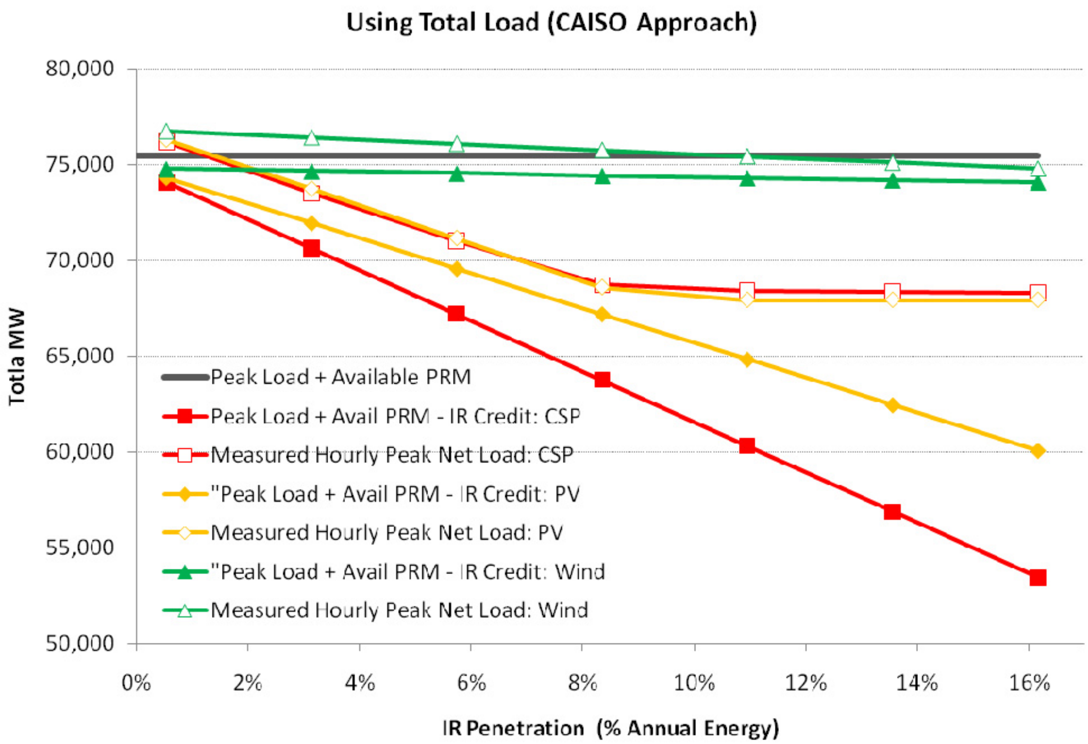


**Figure 10. Comparison of expected reduction in peak net load based on NQC methodology (marker filled in) to the actual measured peak hourly net load (marker open) for increasing penetrations of each variable renewable technology.**

The NQC of a variable renewable resource estimates the amount that the capacity needed to meet the peak load plus available planning reserve margin is reduced by the addition of a variable renewable generator (as shown by the filled in markers in Figure 10). The high NQC of CSP (the NQC used for CSP in RIM is ~96%) drives this requirement down very rapidly with increasing penetration of CSP. The actual reduction in the peak hourly net load plus operating flexibility requirements for the load (open markers in Figure 10) follows the same trend at low penetration of CSP, but after the penetration of CSP exceeds 12 GW (~8% IR) additional CSP capacity no longer reduces the measured peak hourly net load. This leads to a discrepancy between the reduction in needs implied by the NQC methodology and the actual measured reduction in peak net hourly load (reflected by the growing gap between the lines with filled in and open markers for the CSP technology with increasing penetration). At very high penetration (~16% IR) the NQC methodology can overstate the capabilities of CSP to reduce the peak hourly net load by more than 10 GW. The same discrepancy occurs for PV generation for the same reasons. Wind, on the other hand, does not suffer from a divergence between the contribution of wind estimated by the NQC method and the measured contribution of wind, even at penetration levels of 16% IR.

Overall, at very high penetrations of solar (>12-13 GW of nameplate capacity, or just above the level of solar included in the 33% Reference case from RIM) the difference between the capacity credit assigned by the NQC methodology and the actual reduction in peak hourly net load will begin to diverge. Since the NQC overstates the ability of solar to reduce the net load at very high solar penetration, this discrepancy will appear in the analysis as driving an increase in "integration need" (since more conventional capacity will be needed to meet load than estimated by the NQC method). The "integration need" estimated in the CAISO analysis may be slightly affected by this discrepancy in the 33% reference case, but it is expected to have a more noticeable and substantial impact for cases with solar penetrations greater than in the 33% reference case.

*<u>Issue 2: Solar decreases peak net loads for medium penetration levels, but this benefit is not observed when focusing only on incremental load.</u>*

*Using Incremental Load (RIM Approach)*

Instead of focusing on the total load in 2020, as the CAISO does in its analysis of integration need, the RIM model uses the incremental hourly load between the base year (2008) and the study year (2020). This appears to exacerbate the divergence between the assigned capability of variable renewables to decrease net load (using the NQC methodology) and the actual impact of adding variable renewables in reducing the peak hourly net incremental load. Again focusing on solar, the ability of solar to decrease the peak hourly net incremental load is substantial at low penetration, but then falls off as the peak net incremental load shifts to the early evening (Figure 11).

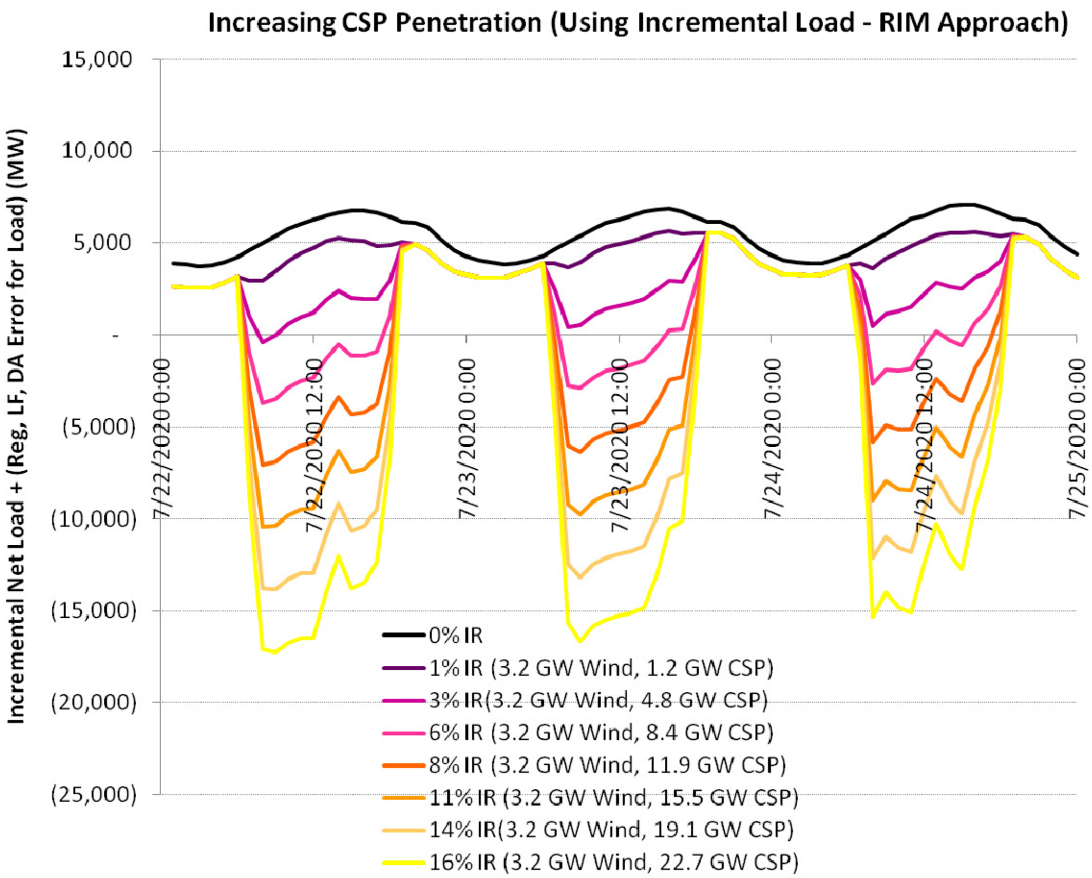


**Figure 11. Change in net incremental load with increasing CSP penetration (assuming no within hour variability and forecast error for CSP).[36]**

Whereas using the total load (as the CAISO does in its analysis) shows that substantial divergence between the capability of solar to offset load implied by the NQC and the actual reduction in the peak hourly net load only occurs after solar capacity exceeds about 12 GW, the incremental load approach used by RIM shows very little ability of solar to offset incremental load after about 0.7 GW of solar are added to the existing renewables (the 1% IR line). The incremental load approach therefore appears extremely sensitive to this discrepancy between the net load reduction capability implied by the NQC

[36] Again note that the 1% line first adds the existing 3 GW of wind and 0.5GW of CSP then adds new CSP. All remaining lines add only new CSP.

methodology and the measured reduction in the peak hourly net incremental load. Figure 12 demonstrates that with ~5 GW of solar (3% IR penetration) there is already a 2-3 GW difference between the load reduction capability implied by the NQC methodology and the reduction in the peak hourly net incremental load. By 12-13 GW of solar (8 % penetration) the gap increases to nearly 6 GW. This 6 GW difference will appear in the RIM model as "integration need" even though the source of the additional conventional capacity is a mismatch between the NQC methodology and the measured reduction in the peak hourly net incremental load.

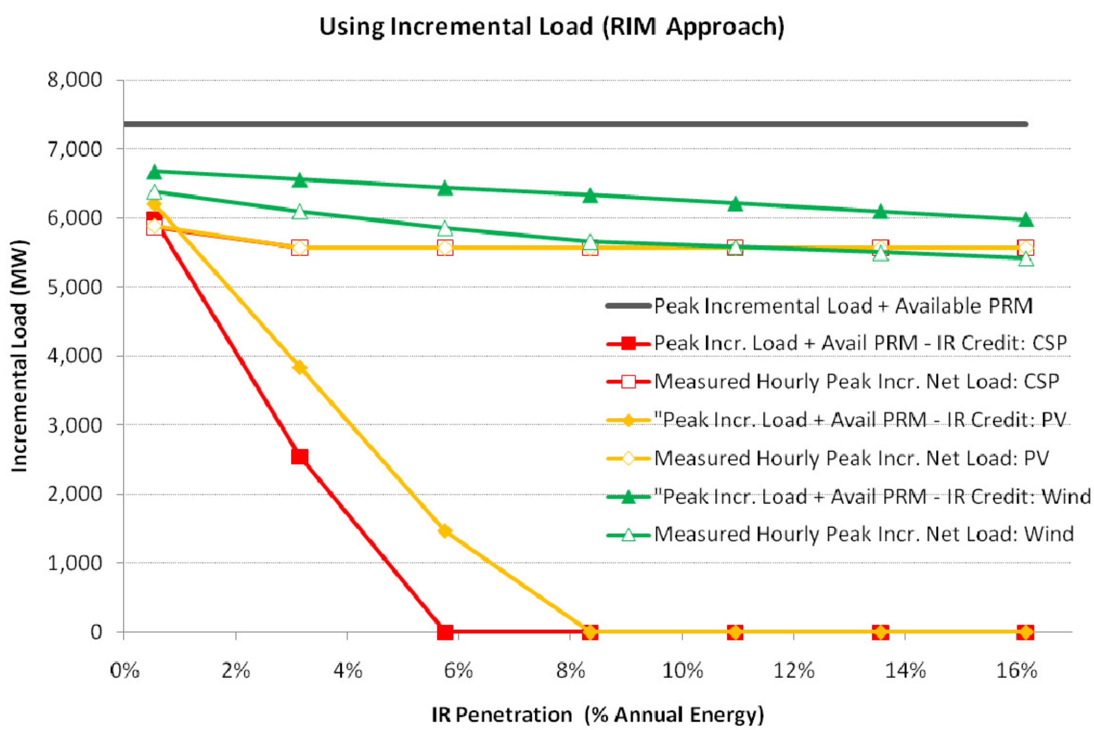


**Figure 12. Comparison of expected reduction in peak net incremental load based on NQC methodology (marker filled in) to the actual measured peak hourly net incremental load (marker open) for increasing penetrations of each variable renewable technology.**

Again it is important to notice that even using the incremental load approach, for *wind* the implied net load reduction from wind's NQC and the measured reduction in the peak hourly net incremental load due to wind never diverge to the same extent they do for solar. In contrast to solar, it appears that very little of the "integration need" calculated in RIM for high wind penetration scenarios will be due to a discrepancy between the variable generation's NQC versus its impact in reducing net incremental load.

## Appendix B. Author Developed RIM Model Thought Experiments

A few different scenarios were developed and tested within the model in order to test the capabilities of the RIM. These "thought experiments" highlight areas where the RIM model produces results that are counter-intuitive and may require modifications to the model.

*(1) Integration costs for 4.8 GW of CSP and 3.2 GW of wind with no day-ahead forecast error, and no intra-hour variability and uncertainty (i.e. make all variable renewables perfectly known on a day-ahead basis and flat within the hour).*

According to Figure 9, adding 4.3 GW of CSP to the existing 0.5 GW of CSP and 3.2 GW of wind will decrease the 2020 peak net load by a substantial amount (assuming that the renewables are perfectly flat within the hour and perfectly forecastable). When these resources are added to RIM, however, it calculates an integration cost of $46/MWh.

This is largely due to the fact that RIM assumes that the way that the units were dispatched in 2008 cannot be increased in any particular hour in 2020. Instead, new units (CT's or CCGT's) must be built if the net incremental load in any hour is positive. Since the addition of 4.8 GW of CSP and 3.2 GW of wind does little to reduce the peak hourly net incremental load (as seen in Figure 10), RIM finds that the total new flexible resource need exceeds what was expected based on the NQC of the variable renewables by 3.1 GW. It therefore builds an additional 3.1 GW of CCGTs and CTs to meet off-peak incremental load growth. These new resources are attributed to integration need and make up the entire $46/MWh integration cost RIM calculates for the variable renewables.

*(2) Integration cost associated with a program that increases off-peak load (i.e. a demand shifting program or an off-peak vehicle charging program).*

One would expect that there should not be any sort of "integration cost" associated with a program that increases off-peak load. In fact, increasing off peak load would increase the utilization of mid-merit units and has often been seen as an overall benefit to the economics of utilities. If one replaces the New Wind IR profile (located in the "IR2"tab) with a "negative generator" or load that increases off-peak consumption (and sets the variability and uncertainty parameters for New Wind to zero), the RIM model should calculate a zero integration cost associated with this increased off-peak load (see Figure B.1-2).

Instead, if a demand program profile that achieves this "valley filling" with at most 22 GW of additional off-peak load is applied, the RIM model adds 18 GW of new CT's and CCGT's and estimates an integration cost of $120/MWh. This new capacity and high integration cost occurs even though the on-peak load in 2020 with and without the off-peak demand program is the same. In addition, the total load with the off-peak demand program is less variable than the total load without the off-peak program.

The high integration cost is due to RIM not allowing existing units in 2008 to increase their output to meet the increased off-peak load in 2020. Instead RIM requires new CT's and CCGT's to be built just to meet these incremental off-peak loads.

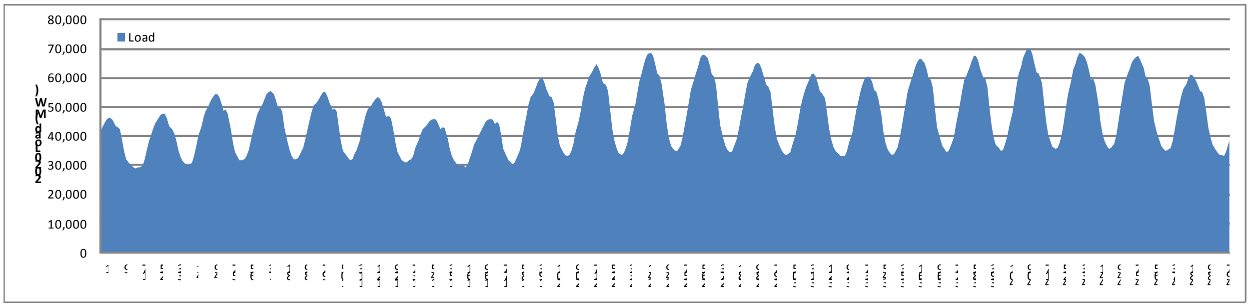


**Figure B.1. 2020 load on July 7-28th**

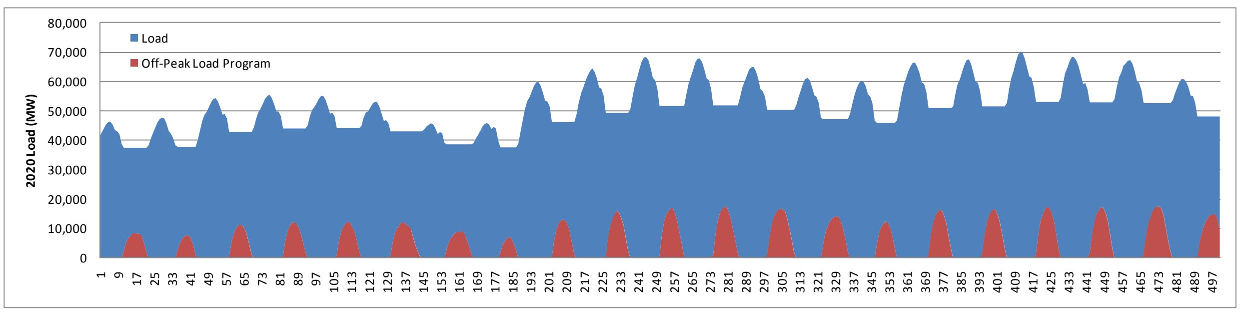


**Figure B.2. 2020 load on July 7-28th with additional off-peak load (in red). Off-peak load represents an electric vehicle charging program for example.**

*(3) High wind example demonstrates that RIM holds more resources in reserve than forecasted wind could physically need*

A case was run in RIM with 16.9 GW of new wind in addition to the existing wind and CSP (enough new wind to meet the 33% RPS target). The critical hour in RIM that drove the need for new flexible resources was September 2, 2020 at 13:00. The day-ahead forecast for the total variable generation for that hour was 1.2 GW. The reserve held in the up direction for the existing renewable resources and the load was 0.9 GW for the same hour. The total amount of reserve held for load and all variable renewables was 5.8

GW. Therefore 4.9 GW of up reserves were held for the new variable renewables in an hour when the forecasted generation was only 1.2 GW. In the worst possible case 1.2 GW of variable resources could drop to zero, requiring at most 1.2 GW of flexible resources to be deployed between the real time and day ahead forecast.

The reserves calculated for this critical hour by RIM exceed the worst possible case by 3.7 GW. Furthermore, RIM calculates that the "integration need" in this case is a total of 4.1 GW which translates to a "fixed integration cost" of $13.3/MWh. This analysis suggests that a portion of this fixed integration cost could be due to RIM holding resources in reserve for situations that far exceed what could physically occur.

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