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California RPS Integration Study: Phase I Summary and Results

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CALIFORNIA RPS INTEGRATION STUDY: PHASE I SUMMARY AND RESULTS

GRID OPERATING IMPACTS AND ANALYSIS
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ABSTRACT

California's recently enacted Renewables Portfolio Standard (RPS, Senate Bill 1078) requires the state's investor-owned utilities (IOUs) to increase the renewable portion of their energy mix, with a goal of 20% renewable energy generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the California Public Utilities Commission (CPUC) establishing a process to select the "least-cost, best-fit" projects. The California Energy Commission (CEC), in support of the CPUC, organized a team to study integration costs in the context of RPS implementation. The analysis team, collectively referred to as the Methods Group, consists of researchers from the National Renewable Energy Laboratory and Oak Ridge National Laboratory and staff members from the California Independent System Operator, Dynamic Design Engineering, and the California Wind Energy Collaborative. This RPS Integration Study is motivated by the RPS's "least-cost, best-fit" bid selection criterion, which requires that indirect costs be considered in addition to the energy bid price when selecting eligible renewable projects. Findings of this report have recently been adopted by the Commission for inclusion as part of the bid evaluation process for renewable energy

generators. Specific issues examined in the report include capacity credit, regulation impacts and costs, and preliminary load-following impacts via the supplemental energy market in California. We also discuss the current status of the RPS Integration Study and some implications for wind integration in other U.S. electric power markets. This paper summarizes the key results from the Phase I report.

PROJECT BACKGROUND

California's recently enacted Renewables Portfolio Standard (RPS, Senate Bill 1078) requires the state's investor-owned utilities (IOUs) to increase the renewable portion of their energy mix with a goal of 20% renewable energy generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the California Public Utilities Commission (CPUC) establishing a process to select the "least-cost, best-fit" projects. As stated in the RPS (399.14.a.2.B), by 30 June 2003, the CPUC must:

> *...adopt a process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses from integrating and operating eligible renewable energy resources.*

The integration costs are the "ongoing utility expenses from integrating and operating eligible renewable energy resources." In the enabling legislation, the costs of transmission investments are explicitly differentiated from the integration costs. The California Energy Commission (CEC), in cooperation with the CPUC, organized a team to study integration costs. The goal of this study is to estimate the integration costs of various generators so that those costs can be incorporated into the least-cost analysis. The total cost is the sum of the direct and indirect costs. Integration costs are a subset of the indirect costs.

The capacity credit of a generator, while categorized as an integration cost, is not a cost at all. Instead, it is the value of a generator's contribution to the reliability of the overall electrical supply system. Relative capacity credit values based on a gas reference unit were determined for various renewable technologies.

A reliability model of the generation supply system was developed based on data from the California ISO (CAISO) and from a commercial generator-reliability database. The model was calibrated and generator-reliability metrics were calculated for each renewable resource type.

Project Goals and Organization

The overall project goal is to develop a valuation methodology for integration costs that can be applied to the selection process of RPS-eligible generation projects. Because project selection is a public process for California, the final methodology will:

- Use input data and analysis tools available in the public domain
- Be fair, transparent, and coherent
- Provide cost estimates that are representative of California
- Be clearly defined, provide repeatable results, and be analyst independent.

The study is divided into three sequential phases, with each phase lasting approximately six months. The initial efforts in Phase I focused on documenting the methodologies to be used for evaluating the integration costs of California's existing renewable and non-renewable generation sources. Goals for development and documentation of the analysis methodologies were:

- The methodology should apply equally and fairly to all renewable generators eligible under the RPS.
- The methodology should clearly define the analysis approach, including the data requirements and the underlying assumptions.
- The documentation should provide a step-by-step process methodology to show how the data would be processed for each generator type.
- The same sample data file should be used when analyzing the results from alternative methodologies so the results can be compared and contrasted.

During Phase 1, the Methods Group was asked to select a single analysis methodology for implementation in subsequent phases of work. The selection criteria for identifying the preferred approach was:

- Was the method independent of a specific institution or company?
- Could the method be applied fairly and consistently?
- Did the method provide results using a minimal amount of data?
- Was the method transparent and analyst independent?
- Has the method been published and peer reviewed?

In Phase II, the key attributes of renewable generators that affect integration cost will be identified and their contributions to integration cost will be analyzed using the methodology developed in Phase I. Recognizing the diversity of renewable energy resources, public input will be solicited to aid in the identification of the attributes. These attributes may include:

- Various generator technologies
- Location and climate
- Level of penetration.

In the third and final phase, the methodology developed in Phase I will be modified so that the attributes identified in Phase II are correctly modeled for the analysis of new renewable energy projects. The final methodology will be released to the public.

DATA PROCESSING

A large quantity of data from the CAISO's Plant Information (PI) system was used. The primary datasets consisted of 1-minute data that were used as the basis for the longer averages that were required for the load following and capacity analysis described below.

One-Minute Data Set

This dataset contains generator and electrical system data collected at 1-minute intervals. Although hourly data are more readily accessible, the analyses required data collected at a higher frequency. CAISO provided the data.

The renewable generator values are aggregates of similar plants. An aggregation is often referred to simply by the renewable type; for example, "biomass generator" refers to the aggregate of several biomass plants, not an individual generator or plant. Aggregation was necessary to protect the confidentiality of individual plants. The generator aggregates are further described below. The descriptions are intentionally limited to preserve confidentiality.

CAISO Plant Information System

The data were extracted from CAISO's PI system, which stores power system operations data for the entire control area. It contains more than 180,000 data fields, including extensive generator data. Because the amount of information collected is so large, the PI system uses a compression scheme to store its data. The compression scheme is lossy, so some data accuracy is sacrificed for more compact storage.

The raw data were reviewed for data errors, and bad data were removed from the file. The 1-minute data files contain 525,600 data points for each signal, and identifying bad data required visual inspection and evaluation to assess the validity of suspect data. To aid in the evaluation, the rate of change was calculated for each signal. Extreme rate changes allowed rapid identification of data dropouts and spikes. The bad data were manually eliminated and left as blanks in the data series. The PI data were also corrected for errors introduced by the change from Standard Time to Daylight Saving Time.

An evaluation of the stored data accuracy was performed by comparing total load values stored in two databases. Total system load was recorded in both the PI and OASIS (CAISO's Open Access Same-Time Information System Web site) databases. The 1-minute PI data were averaged hourly, which allowed direct comparison against the hourly data acquired from the OASIS database. The difference between the PI and OASIS hourly values was used to determine the data storage error, as shown in Figure 1. The standard deviation of data storage error is 160 MW, or ±0.6% of the average annual load.

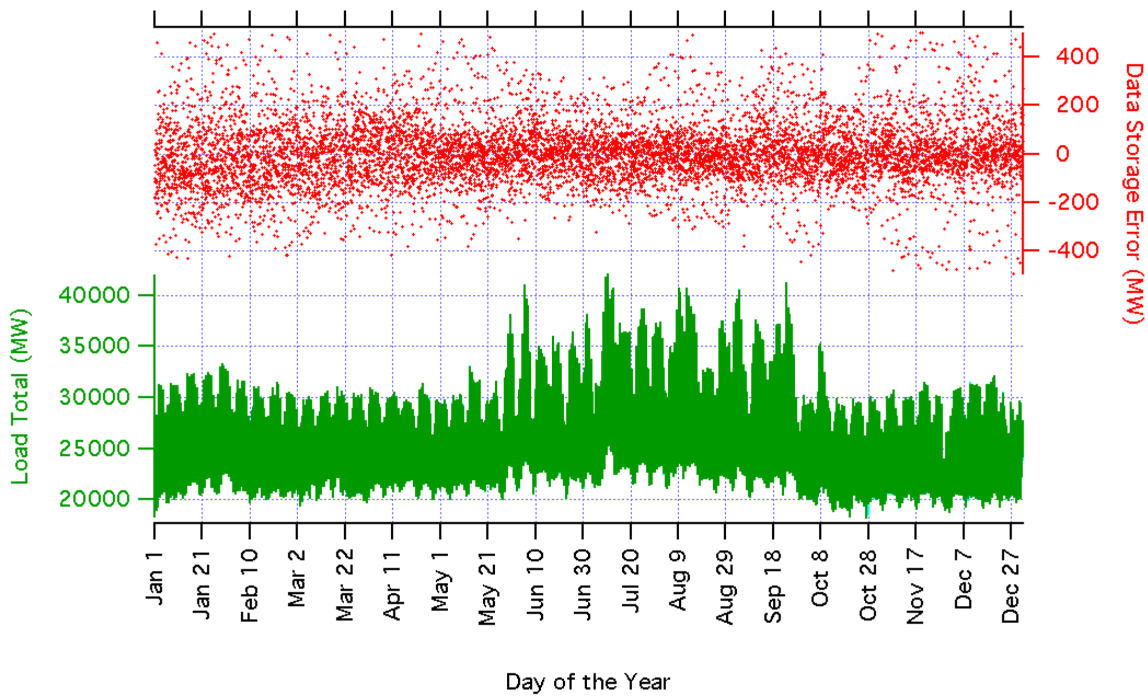

FIGURE 1. DATA STORAGE ERROR OF TOTAL LOAD. THE STANDARD DEVIATION OF THE TOTAL LOAD DATA STORAGE ERROR IS 160 MW.

CAPACITY CREDIT

Because power plants sometimes experience unplanned outages, capacity value (sometimes called capacity credit) is typically measured using a reliability model. Whenever an additional generator is added to the generation mix, the probability of not having sufficient capacity to meet system load declines. This probability is known as loss of load probability (LOLP), and it is typically calculated by a reliability model or an electricity production simulation model. Because LOLP is a probability and must therefore be between 0 and 1, inclusively, we can convert this into an annual measure called loss of load expectation (LOLE), which is often measured in hours per year. A standard reliability target is an LOLE of 1 day in 10 years, which is equivalent to 2.4 hours per year.

To measure the effective load carrying capability (ELCC) of a generator, hourly system loads are increased until the LOLP has declined to its original value. The increase in load that the system can support with the generator, holding annual risk constant, is the ELCC of the generator.

The primary advantage of a reliability-based assessment of capacity value is that it quantifies the risk of not supplying enough generation to meet loads. For example, suppose that two otherwise identical systems differ only because system A has more reliable generators than system B. In this case, system B would have a higher LOLP during peak hours than system A. Note that this does not mean that the lights will go out in system B; rather there is a higher probability of insufficient generation to meet load.

Intermittent renewable generators typically have low mechanical failure rates, but they are not able to generate power when the resource is not available. This intermittency must be included in the reliability calculation, and the standard methods for calculating reliability can be modified to do this[i].

This method for calculating capacity value was proposed by the Methods Group and was accepted by the California Energy Commission. Subsequent comments submitted by Pacific Gas and Electric (PG&E) and Southern California Edison also supported this approach. The method has been used by the Colorado Public Utilities Commission, a study in progress in Minnesota, a recently completed report for the New York Independent System Operator (NYISO), and is the basis for the Pennsylvania-Jersey-Maryland (PJM) wind capacity valuation method. For the California study, the ELCC calculation procedure was altered so that the ELCC of the renewable generator could be calculated relative to a base reference unit. To accomplish this, the benchmark case was run with the renewable generator as part of the generation mix, providing the benchmark reliability level. Then the renewable generator was removed, and the reference unit, chosen to be a gas generator, was incrementally added until the reliability level matched that of the benchmark case. The amount of capacity added from the reference unit is the ELCC of the renewable generator.

Modeling: Annual System Loss of Load Expectation

For the RPS Integration study, we built a reliability model of the generation supply system based on data from the ISO and from a database called BaseCase, a product of Resource Data International. The original data set included detailed maintenance outage data from the California generators. When we included that data in the ELCC calculations, maintenance scheduling had a significant impact on the ELCC of the renewable generators. This impact is caused by a shift in the hourly risk profile when a generator is taken out of service. The ELCC of a generator depends on its ability to reduce the risk of capacity insufficiency. So if a relatively large fraction of generators are unavailable, this shift in the risk profile will have a direct impact on intermittent renewables' ELCC because of the interplay in the timing of intermittent power delivery with the maintenance schedule. After significant discussion at the Public Workshop in Sacramento on September 12, 2003, the decision was made to ignore maintenance scheduling for this study. However, we anticipate that a simpler, more transparent method to calculate capacity value will be developed in Phase III, and this method will recognize the potential capacity value of renewable generators during times of significant scheduled maintenance outages.

Removing maintenance schedules from the reliability model generally shifts the highest-risk hours to those with highest demand. This relationship can be seen in Figure 2, which shows the ranking of the top 500 load hours of the year and the hourly LOLP in each of those hours. As seen in the figure, a much higher relative risk exists during the peak hours than other times.

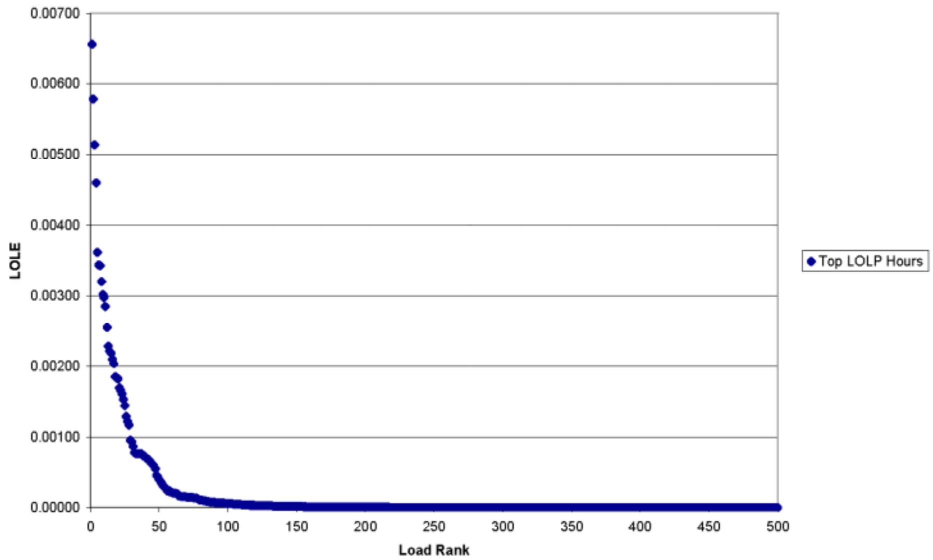

FIGURE 2. RELIABILITY AND TOP 500 HOURS RANKED BY LOLP.

Figure 3 is a LOLE duration curve, showing the number of hours that the system is at alternative risk levels. Aside from the logarithmic scale of this second graph, the overall shapes of the curves are similar, illustrating the relationship between risk and load.

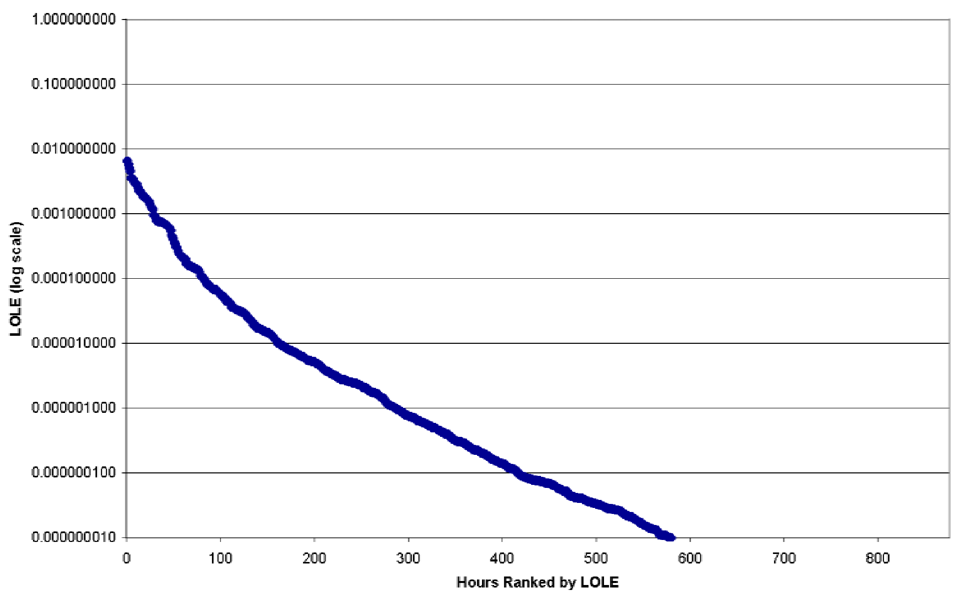

FIGURE 3. LOLE DURATION CURVE.

Conventional Plant Baseline Capacity Credit

For a conventional generator, the primary determinants of ELCC are the rated capacity of the plant and its forced outage rate. For a generator of a given size, higher forced outage rates will reduce its load-carrying capability, and lower forced outage rates will increase its ELCC.

Although most conventional units have relatively low forced outage rates, some older units are not as reliable. Even a generator with a high forced outage rate will make at least a minimal contribution to system reliability and will have a relatively low ELCC.

Figure 4 illustrates how ELCC varies at higher forced outage rates. The graph is based on the California system, adding a generic conventional unit sized at 100 MW, and alternative forced outage rates ranging from 10% to 90% in increments of 10%. Because the baseline gas plant for the ELCC calculation has a 4% forced outage rate and 7.6% maintenance rate, the generic 100-MW unit achieves approximately 100-MW ELCC at a 10% forced outage rate with respect to the reference plant (for illustration, the generic plant has no scheduled maintenance). As the forced outage rate increases, the ELCC declines, reaching a low of 10.4 MW at a forced outage rate of 90%. Although it is difficult to see in the graph, the ELCC as a percent of rated capacity is not the same as the product of the forced outage rate and plant capacity. For example, at a 40% forced outage rate, the ELCC of the generic plant is 62.5 MW.

Intermittent generators such as wind plants generally would be expected to provide a similar ELCC as a conventional generator with a relatively high forced outage rate, whereas intermittent units such as solar would be expected to have higher ELCC rates. Renewable generators that behave more like conventional units, such as biomass and geothermal, would likely have ELCC ratings that are near their respective rated capacity values. Of course, other factors such as fuel supply constraints could have a significant negative impact on the ELCC of these plants.

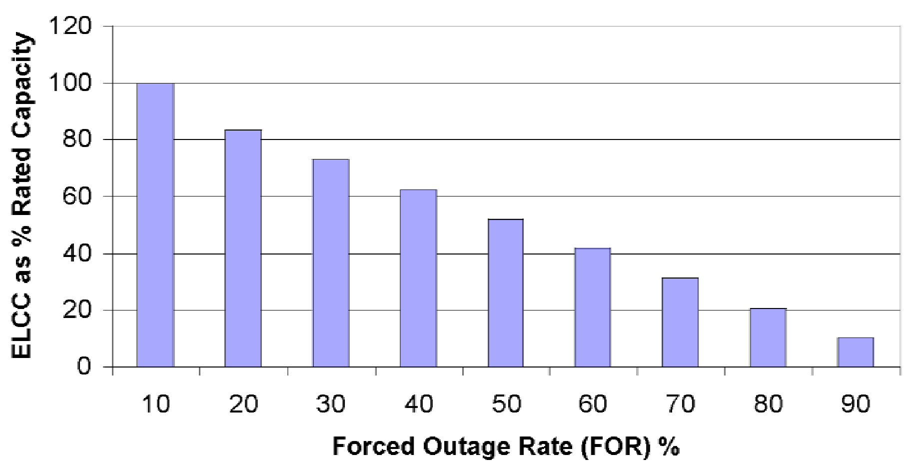

FIGURE 4. ELCC OF GENERIC 100-MW CONVENTIONAL PLANT AS A FUNCTION OF FORCED OUTAGE RATE (FOR).

Representation of Intermittent Renewable Generators in the Reliability Model

Intermittent renewable resources cannot be represented in a reliability model in the same way as a conventional generator because it is important to retain the time-varying nature of the resource in the model. Although several approaches have been applied, a method that is based on the actual statistical distribution of intermittent output over the relevant time period is the most appropriate for reliability modeling.[ii] In this way, the resource is treated in a similar manner as a multi-block generator, with different availability rates for different levels of output. For intermittent generators, this approach is expanded to allow for the changing statistical distribution through time. For studies that focus on operating reliability, it is often desirable to obtain a fine granularity of the intermittent distribution, using as many discrete distributions as possible. For example, using actual hourly wind generation over a 1-year period, we could calculate 24 distributions per week, each one representing a specific hour of the day. For a longer-range planning study, it would be reasonable to calculate these distributions over longer time periods.

The initial reliability results that were presented at the Public Workshop on September 12, 2003,[iii] utilized a large number of discrete statistical distributions that represented 52 typical weeks for the year. A number of participants suggested an approach that would recognize inter-annual variability in both loads and renewable resources. Although a multi-year analysis is beyond the scope of Phase I, the reliability modeling was altered so that the intermittent renewable data distributions could be combined to represent a typical month. Although this does not fully recognize inter-annual variations, it is a step in that direction.

For the intermittent generators we calculated the ELCC as a percent of the maximum capacity attained over the year. For existing resources, this means that some installed capacity may not be accounted for in the calculation. However, the rated capacity for some wind plants often does not take account of the generating capacity that is no longer available. These older turbines have often not been properly maintained and are no longer useful. Therefore the ELCC as calculated as a percentage of maximum capacity is probably representative of the existing fleet capability, and this is likely to be true for turbines that are based on modern technology as we move to the future.

Wind Capacity Credit

The three wind resource areas were modeled separately for this study. It was not possible to obtain dis-aggregate wind production data, but we don’t believe that is a significant limitation of these results. The ELCC of a given resource area reflects the combined reliability impact of the generators at that general location. We would expect that some individual wind plants contribute more to reliability (and therefore have a higher ELCC) than others (with a lower ELCC). As this project moves forward, it will be important to quantify expected ELCC or capacity credit for individual bidders, but that will be addressed in the future.

The results from the three wind resource areas appear in Figures 4 through Figure 6. As indicated, wind in the Altamont area contributed ELCC of 26.0%, San Gorgonio 23.9%, and Tehachapi 22.0%.

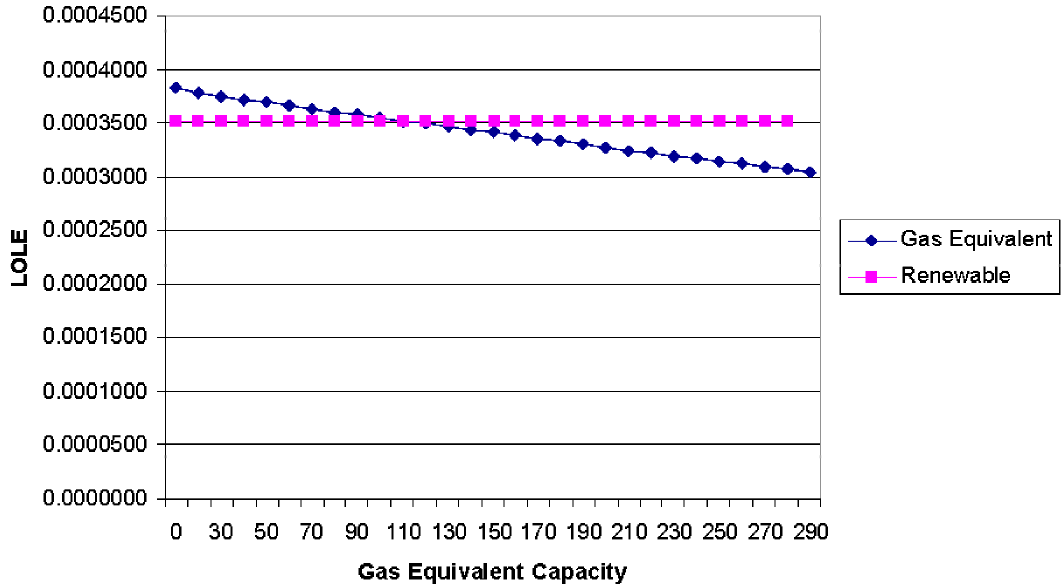

FIGURE 5. WIND RELIABILITY CURVE IN ALTAMONT REGION.

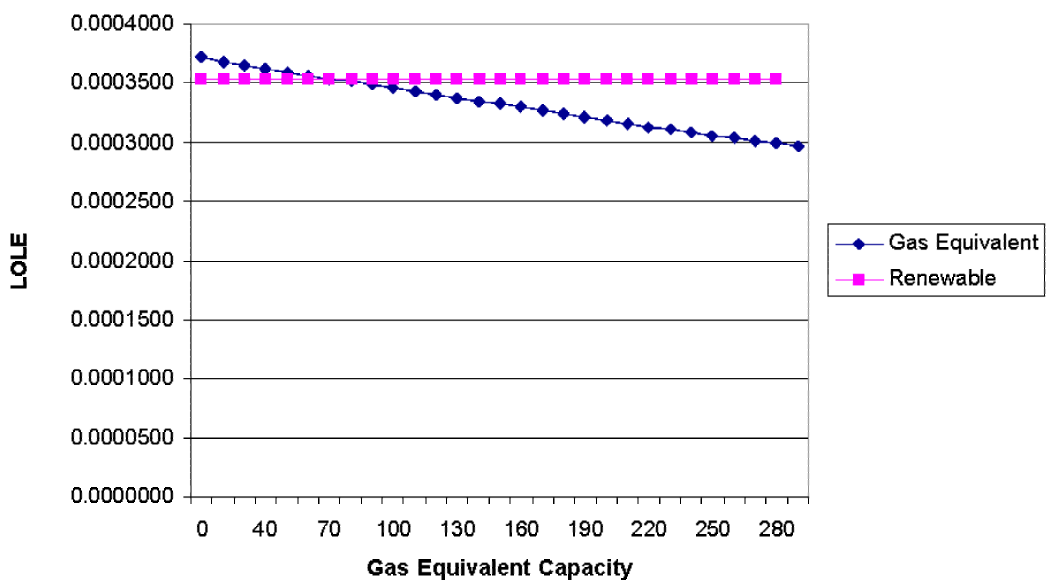

FIGURE 6. WIND RELIABILITY CURVE IN SAN GORGONIO REGION.

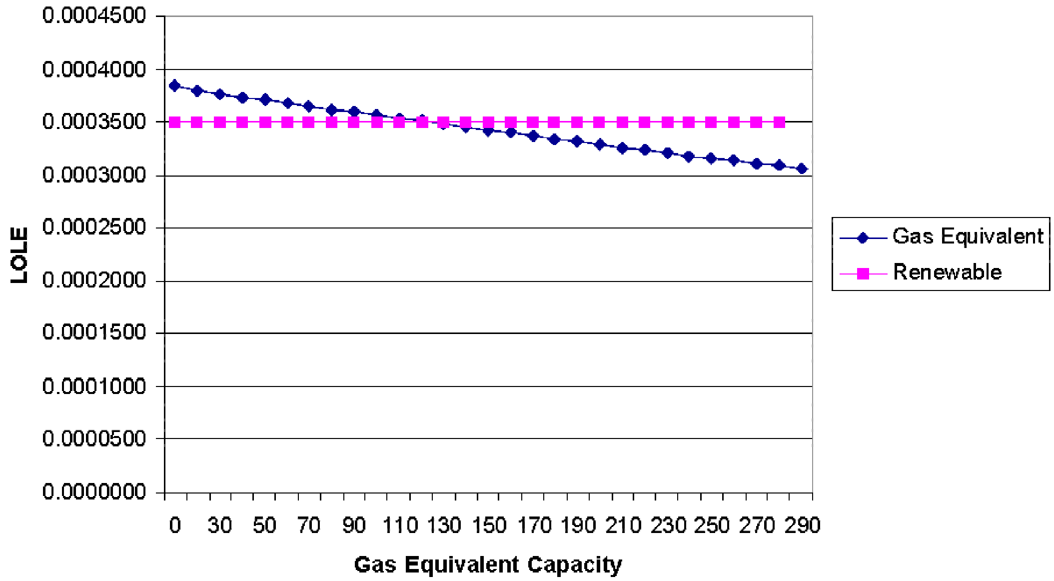

FIGURE 7. WIND RELIABILITY CURVE IN TEHACHAPI REGION.

Intermittent Capacity Credit Summary

Table 1 and Figure 8 show the capacity credit calculated from each of the renewable technologies. The percentages are based on estimated nameplate rating of the generator.

TABLE 1. CAPACITY CREDIT RESULTS

Resource	**Relative Capacity Credit**
Medium Gas	100.0%
Biomass	97.8%
Geothermal (constrained)	73.6%
Geothermal (unconstrained)	102.3%
Solar	56.6%
Wind (Altamont)	26.0%
Wind (San Gorgonio)	23.9%
Wind (Tehachapi)	22.0%

As expected, the biomass and geothermal resources have high ELCC values (in the absence of fuel or other constraints) because they behave most like conventional resources. Wind ELCC is significantly lower than the other resources, but it shows that wind can help reduce system risk, albeit by a modest amount when compared to other resource types. The wind ELCC values are consistent with what we would find for a conventional unit with a high forced outage rate—about 75%—as indicated in Figure 4. Although detailed discussion of biomass, geothermal, and solar are outside the scope of this paper, we note that some geothermal generation is steam-constrained, so we include both the constrained and unconstrained cases separately.

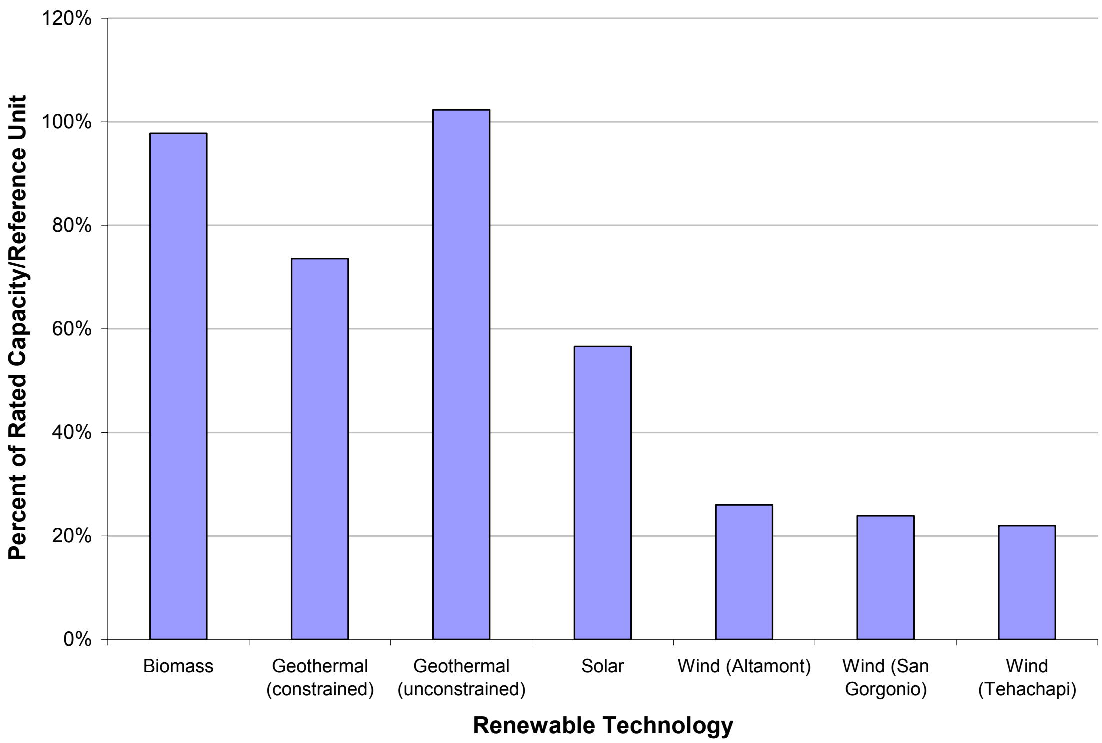

FIGURE 8. ELCC RESULTS FOR VARIOUS RENEWABLE TECHNOLOGIES.

Simpler Methods for Calculating Capacity Credit

One of the goals of this study is to develop a simpler, transparent method to calculate the capacity credit of renewable resources. Although Phase I has begun that process, we are awaiting analysis of additional data before suggesting a simpler method.

Capacity Analysis Recommendations for Bid Scoring

The capacity analysis done in Phase I can be used to help rank potential bids from biomass, geothermal, and wind renewable energy providers. We recommend additional study of solar before these capacity findings are applied toward bid selection.

Data from three wind resource areas were available for analysis in this study. Wind bidders from each of these areas would almost certainly be able to achieve at least the level of capacity credit as calculated using the ELCC methods because of the significant improvements in wind generating technology that have occurred in recent years. With the newer technology that is currently being installed at U.S. wind plants, these technical improvements are improving the energy capture at lower wind speeds and at lower air densities. Although it is likely that newer technology near the existing resource areas will have higher ELCC, a more complete assessment of this issue is incomplete at present. Initial data from recently installed wind turbines in the Solano County wind resource area suggest that additional energy capture can also result from good site location. Until further analysis can be done, wind power plants could be expected to provide at least the ELCC levels at the respective resources areas analyzed for this Phase I report.

Applicability of Results for Increasing Renewable Penetration Levels

To help determine the sensitivity of the ELCC results to higher renewable penetrations, a set of model runs was carried out at double the current level of renewable resources. To accomplish this, the intermittent chronological output levels were doubled for each wind site, solar, and the hourly geothermal time series. For the unconstrained geothermal and biomass cases, the capacity rating of the respective resource was doubled. The combined renewable resources were added to the base case, and each renewable resource ELCC was estimated, one at a time, using the same procedure as the base case.

The ELCC of each wind resource area declined slightly. Altamont wind declined from 26% to 24%, San Gorgonio declined from 24.9% to 22.9%, and Tehachapi declined from 22.0% to 19.9%. There were no changes in geothermal or biomass.

It is important to interpret these results in the context of potential renewable bids in the near future. First, it is widely known that scaling up existing intermittent renewable plants, as done for this increasing penetration analysis, overstates the variability of the output and contributes to reliability on a declining marginal basis. Adding capacity during the same hours will cause a drop in the potential reliability benefit of the resource because reliability in those hours has already improved somewhat. Second, existing wind technology has improved significantly beyond the technology that is currently in widespread use in California. Improvements in control algorithms, lower-wind-speed turbines, and blade-pitching to compensate for lower air density at higher temperatures are the most notable examples of these improvements. Although Phase II will allow us to do a better job of quantifying these variables, we believe that these improvements, along with different wind resource characteristics and better siting, imply that the Phase I capacity results represent robust, conservative values for at least a doubling of renewable capacity in California.

Capacity Valuation: Phase II Analysis

Since one of the objectives of the RPS Integration Study is to help evaluate bids from a potentially large number of renewable energy suppliers, it is imperative that the final product of this study has the capability of differentiating between multiple bidders. The Phase I work did not have access to disaggregate renewable generation data. However, we don't believe that to be a significant impediment to the goal of providing a method to distinguish between the capacity values of multiple bidders. The next two phases of this project will develop a relatively simple, transparent method to approximate the ELCC of bidders with different resource characteristics.

The development of a bid evaluation method for capacity value will be based on an approximation to ELCC based on the timing of resource output (in the case of intermittent renewable generators) relative to hours of potentially high risk.

REGULATION AND DECOMPOSITION OF LOADS

The regulation analysis methodology has been applied to a variety of other control areas to quantify the ancillary service impacts of loads and intermittent resources. It determines the regulation and load following impacts to the control area. These impacts are the result of fluctuations in aggregate load and/or uncontrolled generation that must be compensated. Once the requirements are quantified, the method then determines the costs incurred in terms of greater amounts of purchased regulating capacity and greater use of the short-term energy markets.

Loads within the control area can be decomposed into three elements (Figure 9). The first element is the initial load (base) of the scheduling period, 80 MW over the 1-hour period shown in this case. The second element is the trend (ramp) during the hour and from hour to hour (the morning pickup in this case); here that element increases from 0 MW at 7 a.m. to 18 MW at 8 a.m. The third element is the rapid fluctuations in load around the underlying trend; as shown here the fluctuations range over ±1 MW. Combined, the three elements yield a load that ranges from 79 to 98 MW during the hour.

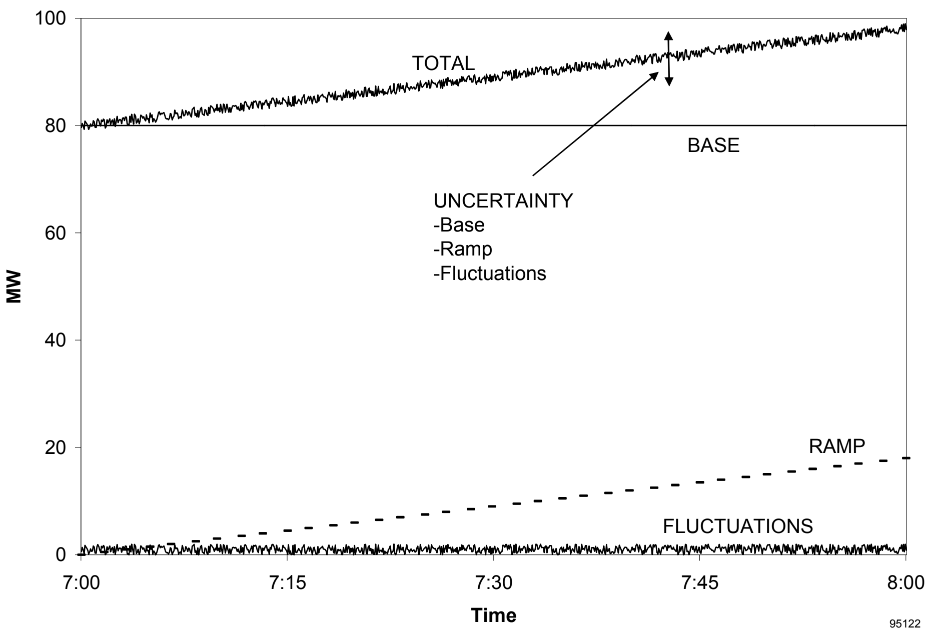

FIGURE 9. DECOMPOSITION OF HYPOTHETICAL WEEKDAY MORNING LOAD.

The system responses to the second and third components are called load following and regulation. These two services ensure that, under normal operating conditions, a control area is able to balance generation to load. The two services are briefly defined[iv,v,vi] as follows:

- *Regulation* is the use of online generating units that are equipped with automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. In so doing, regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.
- *Load following* is the use of online generation equipment to track the intra- and inter-hour changes in customer loads. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation (10 minutes or more rather than minute to minute). Second, the load-following patterns of individual customers can be highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns.

Assessing the individual customer, or renewable generator, contribution to the overall regulation requirement necessarily involves evaluating generation performance. A control area is not expected to perfectly match generation and load instantaneously. Rather, generation matches load with some time lag, and, therefore, generation matches load only approximately. Although the AGC systems at most utility control centers send, raise, and lower pulses to individual generators as frequently as every 2 or 4 seconds, generators do not follow such short-term load fluctuations. Our prior work[vii] suggests that generation follows load at the 1- to 2-minute interval.

There is no hard-and-fast rule to define the temporal boundary between regulation and load following. If the time chosen for the split is too short (e.g., 5 minutes), too many fluctuations will appear as load following and too few as regulation. If the boundary is too long (e.g., 60 minutes), too many fluctuations will show up as regulation and too few as load following. But in each case, the total is unchanged and is captured by one or the other of these two services.

Calculation of the Regulation Component

The regulation requirements of the CAISO system were analyzed and the impacts of individual uncontrolled generators on the total regulation requirement were determined utilizing a method developed by Oak Ridge National Laboratory (ORNL). This method has been used to analyze control area performance, individual loads, non-conforming loads, non-AGC generators, and wind plants for a number of utilities, including American Electric Power (AEP), Central & South West (CSW), Northern Indian Public Service Company (NIPSCO), Bonneville Power Authority (BPA), Commonwealth Edison (ComEd), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Alberta, New Brunswick, and Ontario Hydropower. Electrotek used the method in its analysis for Xcel[viii], Great Rivers, and the Electric Reliability Council of Texas (ERCOT).

Specifically, a 1-minute average energy data and a 15-minute rolling average were used to separate regulation from load following. The rolling average for each 1-minute interval was calculated as the mean value of the seven earlier values of the variable, the current value, and the subsequent seven values:

$$\mathit{Load\ Following}_t = \mathit{Load}_{estimated\text{-}t} = \mathit{mean}\ (L_{t-7}, L_{t-6}, \ldots, L_t, L_{t+1}, \ldots, L_{t+7}) \qquad [1]$$

$$\mathit{Regulation}_t = \mathit{Load}_t - \mathit{Load}_{estimated\text{-}t} \qquad [2]$$

This method is somewhat arbitrary and imperfect. It is arbitrary in that the time-averaging period (15 minutes in this project) and the temporal aggregation of raw data (1 minute) cannot be predetermined. In principle, the control-area characteristics (dynamics of generation and load and the short-term energy market interval) should determine these two factors.[ix] For this study, the 15-minute rolling average was selected because it provides good temporal segregation and captures the characteristics of California's supplemental energy market.

The standard deviation of the 1-minute regulation values for total system load was calculated hourly as the metric for regulation performance. A utility typically carries about three standard deviations of regulating reserves to assure adequate CPS performance.

Short-Term Forecast Versus Rolling Average

In practice, system operators cannot know future values of load. They generally produce short-term forecasts of these values to aid in generation-dispatch decisions. There are two problems with using short-term forecasts to separate regulation and load following. First, while aggregate load forecasts are typically well developed, short-term forecast methodologies for non-dispatchable conventional and renewable generators are not. The CAISO is currently developing an improved forecasting tool for wind, for example. Second, even when they are being used for operations, the short-term forecast results for individual generators or loads are typically not saved. Finally, the rolling average is a reasonable analytical substitute in studying other control areas. The rolling average, like the system operator, is constantly moving the regulating units back to the center of their operating range. When consistent, robust short-term forecasts are available and verified for all renewable generation technologies, this analysis can be repeated without using the rolling average.

The use of the rolling average rather than the short-term forecasts can impact the allocation of variability between the regulation and load following services slightly. Significantly, the method ensures that total variability is captured in one or the other service and that there is no double counting.

Individual Renewable Generator Metrics

Once the hourly regulation requirements for the entire system were determined, we calculated individual contributions to that total requirement. Regulation aggregation is nonlinear; there are strong aggregation benefits. It takes much less regulation effort to compensate for the total aggregation than it would take if each load or generator compensated for its regulation impact individually. While this is a great benefit, it also means that there is no single "correct" method for allocating the reduced total regulation requirement among the individuals. An allocation method should:

- Recognize positive and negative correlations
- Be independent of sub-aggregations
- Be independent of the order in which loads or resources are added to the system
- Allow dis-aggregation of as many or few components as desired.

The method used in this study meets these criteria. It was developed by ORNL to analyze the impacts of nonconforming loads on power system regulation. It works equally well when applied to non-dispatchable or uncontrolled generators.

With the ORNL method, it is not necessary to know every individual's contribution to the overall requirement. Specific individual's contributions can be calculated based on the total requirement and the individual's performance. Because regulation is the short, minute-to-minute fluctuations in load, the regulation component of each individual is often largely uncorrelated with those of other individuals. If each individual's fluctuations (represented by the standard deviation ($\square_i$) are completely independent of the remainder of the system, the total regulation requirement ($\square_T$) would equal:

$$\sigma_T = \sqrt{\sum \sigma_i^2} \qquad [3]$$

where i refers to an individual and T is the system total.

For the case of uncorrelated contributions, the share of regulation assigned to each individual is:

$$Share_i = \left(\frac{\sigma_i}{\sigma_T} \right)^2 \qquad [4]$$

The more general allocation method, developed by ORNL and presented in Equation 5, accommodates any degree of correlation and any number of individuals. This allocation method is more complex but no more data-intensive than the previous method. This method yields results that are independent of any sub-aggregations. In other words, the assignment of regulation to generator (or load) g_i is not dependent on whether g_i is billed for regulation independently of other non-AGC generators (or loads) or as part of a group. In addition, the allocation method rewards (pays) generators (or loads) that reduce the total regulation impact.

$$Share_i = \frac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T} \qquad [5]$$

The general allocation method (Equation 5) was used to analyze the impacts various individual renewable generators had on the overall system's regulation requirements.

Calculated hourly regulation requirements were compared with hourly regulation purchases by the CAISO and hourly regulation self-provided by scheduling coordinators. Total regulation requirements were then allocated back to individuals. Hourly regulation costs were used to allocate the cost of regulation back to individuals. Total (i.e., procured + self-provided) pre-rational buyer regulation purchase data were not available, so the total regulation purchase values were determined by scaling with the ratio of total and procured regulation including the rational buyer. This guaranteed that we accounted for the correct amount of regulation. All of the CAISO's regulation requirements were allocated based on the short-term variability impacts of the loads and renewable generators. One-minute, synchronized, integrated-energy, time series data for total load and each renewable generator of interest are required to carry out these calculations.

The CAISO runs hourly markets for regulation up and regulation down. Price and quantity data from these markets were used to determine impacts on the quantity of regulating resources procured and the cost of the additional regulation. Scheduling coordinators are also allowed to self-provide regulation. The amount of self-provided regulation was added to the amount of purchased regulation to obtain the total regulation amount. There is no price associated with self-provided regulation so the market price of the purchased regulation for the same hour was used to calculate the total dollar value of regulation for each hour.

Regulation Cost Analysis Results

We applied the regulation cost analysis method to the CAISO system to analyze the impact existing renewable energy resources had on the overall system regulation requirements. We assume that the CAISO is currently purchasing the correct amount of regulation and appropriately controlling the system to achieve a good balance of cost and reliability performance. We allocated the amount and cost of regulation to the aggregated loads and selected renewable generators.

Total Load Regulation Cost

The CAISO forecasts regulation requirements hourly and runs hourly regulation-up and regulation-down markets to meet those needs. Scheduling coordinators are allowed to self-supply regulation, reducing the amount of regulation that the CAISO must purchase in the hourly markets. The CAISO purchased an average of 189 MW of up regulation and 186 MW of down regulation in 2002 for average prices of $12.50/MW-hr (MW-hr denotes a capacity value measured in MW for 1 hour; MWh denotes the unit of energy by operating a unit at 1 MW for 1 hour) and $14.01/MW-hr respectively. The amounts purchased ranged between 0 and 510 MW for regulation up and between 0 and 484 MW for regulation down. The prices ranged from $0 to $56/MW-hr for regulation up and $1 to $88/MW-hr for regulation down. The total cost of purchased regulation was just over $46 million in 2002. With the California system load ranging between 18 and 42 GW and averaging nearly 27 GW, purchased regulation added nearly $0.20/MWh to the average price of electricity for California loads in 2002. Scheduling coordinators self-supplied an additional average 212 MW of up regulation and 237 MW in 2002. Valuing this contribution at the same hourly market clearing prices as that purchased by the CAISO adds $52 million to the cost of regulation for the CAISO system. The total cost of regulation was then just over $98 million, resulting in a $0.42/MWh adder to the average price of electricity for California loads for 2002 for regulation.

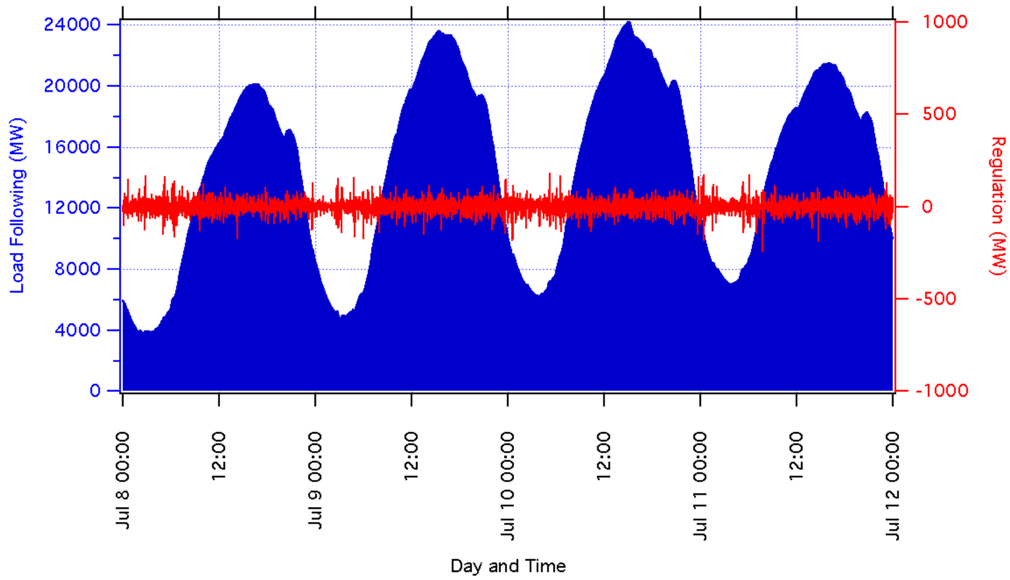

FIGURE 10. REGULATION COMPONENT SEGREGATED FROM LOAD FOLLOWING AND DISPLAYED ON AN EXPANDED SCALE.

Regulation Cost Components

The dominant cost for a generator in supplying regulation is the opportunity cost associated with maneuvering the generator in the energy market so that it has capacity available to sell in the regulation market. For example, a 300-MW generator with an energy production cost of $25/MWh would have to bid $20/MW-hr of up regulation if the energy market were clearing at $45/MWh. The $20/MW-hr is needed to make up for the profit that will be lost when the generator withholds capacity from the energy market in order to supply regulation.

The cost of down regulation is similarly based upon the relationship of the supplying generator and the energy market. When energy prices are low (typically at night) and generators are at minimum load, they incur a cost for running above minimum load in order to supply down regulation. For example, a generator with a 100-MW minimum load and an energy production cost of $25/MWh would have to bid $10/MW-hr of regulation if the energy market were clearing at $15/MWh because it will lose $10 for every MWh it must sell to the energy market to get its base operating point high enough to provide room to regulate down. This complex relationship between regulation costs and energy prices results in volatile regulation prices, as shown in Figure 11. This graph presents average regulation price that was weighted by the actual reg-up and reg-down purchases.

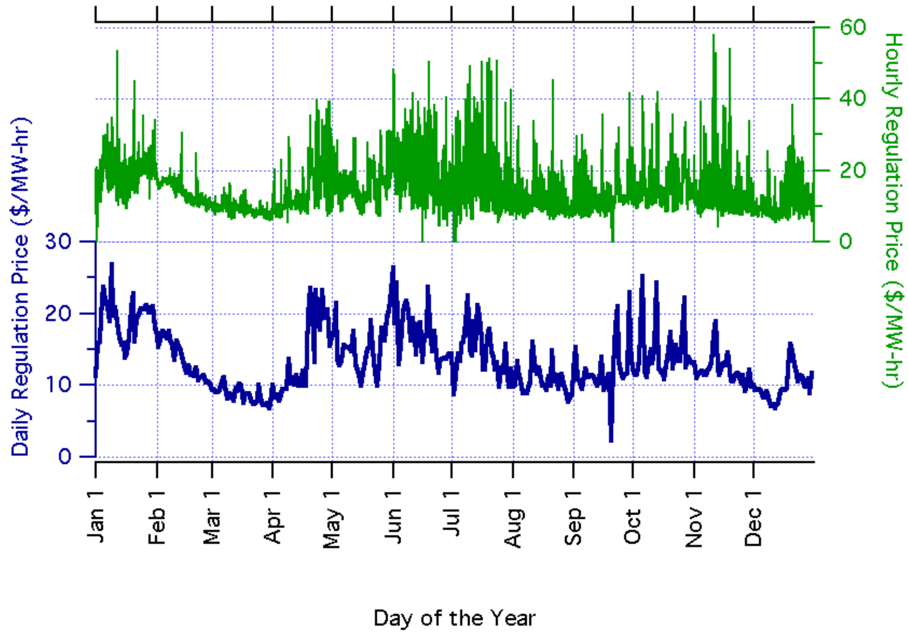

FIGURE 11. DAILY WEIGHTED AVERAGE REGULATION PRICES WERE VOLATILE.

Resource Regulation Cost

With 1 year of 1-minute data for total system load, seven renewable resources, and a medium-size gas plant coupled with hourly regulation purchase and self-provision amounts and prices, we allocated the cost of regulation. As described previously, we first separated the minute-to-minute regulation fluctuations from load following and base energy for the total load and each resource. We used the standard deviation as a good metric for variability. We chose hourly intervals because the regulation markets clear hourly with hourly prices and quantities. Total purchased and self-provided regulation and total purchased regulation cost were allocated to the total load and each of the individual resources hourly. The hourly calculations are summarized into annual averages and are presented in Table 2.

TABLE 2. ANNUAL AVERAGE ALLOCATION OF PURCHASED REGULATION COSTS.

(Negative numbers denote a cost while positive numbers indicate a value.)

Resource	Regulation Cost ($/MWh or mills/kWh)	
	Procured	Total
Total Load	-0.20	-0.42
Medium Gas	0.04	0.08
Biomass	0.00	0.00
Geothermal	-0.05	-0.10
Solar	0.02	0.04
Wind (Altamont)	0.00	0.00
Wind (San Gorgonio)	-0.21	-0.46
Wind (Tehachapi)	-0.07	-0.17
Wind (Total)	-0.08	-0.17

Note: Use caution when applying $/MWh as a regulation cost metric.

Using $/MWh as a metric for regulation is both useful and dangerous. It is useful because we really want to know how much this ancillary service (something we are forced to buy but don't really want) adds to the cost of electricity (something that does useful work for us and we want to purchase). In that sense, a metric that is in the same units ($/MWh) as the commodity we are purchasing is very useful. It is dangerous because the amount of regulation required and the price have almost nothing to do with the amount of energy consumed or produced. The amount of regulation depends on the short-term volatility of the generation or load, not the energy consumption or production. Use $/MWh in reference to regulation with great caution.

An important note is that all of the results are quite small. They are, at best, at the edge of the error range for this data. We can say that the impacts of the individual resources are not significantly larger than what is shown. However, it is difficult to have confidence in the precision of these small numbers. The CAISO PI data storage system was not designed to maintain this level of resolution for small fluctuations.

Given the caution on the precision of the results, it is not surprising that both the medium gas plant and the solar plant have slightly positive numbers. The daily solar cycle tends to follow the daily load pattern. This primarily helps with load following and improves the performance of the solar plant in the energy market. A small benefit also flows into the regulation performance. Similarly, the medium gas plant tends to chase the energy market price, helping load following. A small portion of this benefit also flows into regulation performance.

Not unexpectedly, the wind plants impose a small regulation burden on the power system. This was expected because there is no apparent mechanism that would tie the wind plant performance to the power system's needs in the regulation time frame and result in a benefit like there is for solar plants or conventional plants that are following price signals. The regulation burden is low because there is also no mechanism that ties wind plant fluctuations to aggregate load fluctuations in a compounding way either. Wind and load minute-to-minute fluctuations appear to be uncorrelated. Hence they greatly benefit from aggregation. Interestingly there is a range of regulation performance that may be related to the geographic location of the wind plants.

Regulation Cost Analysis Recommendations

This preliminary analysis shows that there is little regulation impact imposed on the CAISO power system by the existing renewable resources. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are close to the limits of the study accuracy.

It appears that different wind locations may have different regulation performance. This should be studied further. Similarly, the overall study accuracy should be refined. One-minute data on total system load and each of the resources should be collected and saved at higher resolution than the current PI system accommodates. Analysis should be performed quarterly and annually to update this report.

LOAD FOLLOWING ANALYSIS

Previously we discussed how California's system loads and generation can be decomposed into three components: base load, load following, and regulation. The base load can be identified quite simply as the constant, unchanging portion. Load following refers to the intra- and inter-hour changes in load or generation. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation (10 minutes or more rather than minute-to-minute). Second, the load following patterns of individual customers can be highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load following changes are often predictable and have similar day-to-day patterns.

Separating load following from regulation required that we define a temporal boundary between them. Selection of a particular temporal value will determine whether a change in load falls into one service category or the other. If the time chosen for the split is too short (e.g., 5 minutes), too many of the fluctuations will appear as load following and too few as regulation. If the boundary is too long (e.g., 60 minutes), too many fluctuations will show up as regulation and too few as load following. It is important to note that in either case, the total is unchanged and is captured by one or the other of these two services.

Much of the energy required for load following is obtained from the CAISO hour-ahead energy market. This market operates on a 10-minute basis, and participating generators can be dispatched up or down at the opening of each market cycle. The 10-minute timeframe defined by CAISO for the supplemental energy market was used as the basis for selecting the temporal boundary between load following and regulation in this analysis. Load following was calculated as a rolling average of load (or generation), and a 15-minute averaging period was selected to fully encompass each 10-minute market cycle.

Market Settled Costs

The hour-ahead energy market is used to manage supplemental energy requirements. Since the CAISO energy market operates at the load following time scale, integration costs associated with the market were denoted as load following integration costs. Participants in the CAISO hour-ahead energy market submit bids for delivery of energy at the certain cost and at a certain time. The hour-ahead market bids are due 150 minutes prior to the opening of each market cycle. At any given time, the supplemental energy market generates a "stack" of bids from participating generators. Energy is purchased as needed to meet load demand by selecting generation resources from the bid stack. CAISO uses an automated system for selecting the most economic generators and calculating the dispatch instructions.

The hour-ahead market pays generators for energy that is provided according to specified rules and procedures. CAISO developed explicit market based methods for settlement (payments or charges) of energy deliveries for controllable generators (conventional, biomass, geothermal) and for intermittent resources (wind, solar, hydro). Explicit settlement processes can be applied to any generator that deviates from its schedule without specific dispatch instructions (uninstructed deviations). When a generator provides less energy than instructed, it is compensated for the amount of the instructed energy that was actually delivered. If a resource provides more energy than instructed (expected), the additional energy delivered is settled as uninstructed energy.

Since CAISO has rules and procedures in place for settlement of imbalance energy caused by deviations from schedules and dispatch instruction, those costs are settled explicitly by the market and are not considered integration costs in this analysis. Integration costs as defined in this work are those costs implicitly borne by the system that are not allocated to a specific generator or load. Uninstructed energy is not considered an integration cost because it is settled explicitly by the market and any costs incurred by the system are charged to the specific generator.

Load Following Integration Costs

The load following analysis in this effort is focused on implicit costs associated with integration of renewable energy. Explicit, market-settled costs were not considered. Integration of large amounts of renewable generators could potentially increase errors between scheduled and actual generation. Increases in scheduling error could potentially change the composition or size of the generator stack. If such a distortion of the bid stack occurred, it could shift the market to marginal generators, whose costs were higher. That could increase the price of energy in the market and thus create implicit costs that were imposed on the system by the renewable generators.

Our initial analysis focused on the potential impacts to the generator stack caused by renewable generation scheduling error. The methodology for the analysis was organized to determine whether renewable generators had significant impacts on the systematic errors forecasts and schedules in the hour-ahead market. The goal of the methodology was to analytically determine the impact of renewable generators on system scheduling error. If renewable generators created systematic errors that significantly increased the need for generation resources, then they could have a material effect on the composition of the generator stack or the ex-post price for energy.

The analysis methodology first determined system forecasting and scheduling errors for the benchmark case without renewable generators. CAISO prepares hour-ahead forecasts of its generation requirements, which represent its best estimate of actual system load. The scheduling coordinators provide schedules that are designed to economically meet the forecast generation needs. The scheduling coordinators typically schedule significantly less generation than is needed for on-peak load and rely upon the hour-ahead market to provide the balance. The difference between the forecast load and the scheduled load is defined as the scheduling bias. Forecast and scheduling errors in the benchmark case provide an indication of the variability inherent in operating the utility grid and are important because they define the normal range of errors without renewable generation impacts.

The next stage of the analysis was to calculate the scheduling errors for each renewable generator of interest. Worst-case scheduling was used to estimate the impacts of the renewable generators; the analysis is therefore conservative. Bids for the hour-ahead market are due 150 minutes prior to each market cycle. The scheduled output for the hour-ahead market was defined by a simple persistence model, assuming that output 150 minutes in the future would be equal to output at the present time. For solar generators, it was assumed that scheduled output was equal to what it had been on the previous day at the same time period.

The total forecasting error, including the renewable resources, was calculated by combining the system forecasting error (without renewables) with the additional scheduling error produced by the renewable resource in question. The forecasting error, including renewable generators, was then compared against the benchmark case and reviewed to identify the significant differences. The goal of this analysis was to determine whether the renewable resources significantly changed the forecasting error and modified the generator bid stack.

The scheduled load provided by the scheduling coordinators is often thousands of megawatts less than the forecast load created by CAISO. The large negative bias of the hour-ahead schedules provides an indication of the amount of the generation assets available in the supplemental energy market. The data indicate that the scheduling coordinators are comfortable with the depth of the generator stack; they can call up at least 6000 MW of generation from the market whenever it might be needed. For our initial analysis, the scheduling bias was used as a proxy for estimating the depth of the generator stack. It was used for comparison purposes in determining the significance of renewable impacts on the system error.

A worst-case scheduling scenario was used for wind scheduling in this analysis so that the results would be conservative. The hour-ahead schedules for the wind generator of interest were developed using a simple persistence model that assumed that power output in 150 minutes would be equal to current output. This model provides a schedule of output for the hour-ahead market and is a conservative (worst-case) approach. Use of meteorological forecasting models will reduce scheduling error and reduce the significance of renewable impacts from those calculated here.

The scheduling error for each renewable resource was combined with the system forecasting error for each hour of the sample year. The result of this combination showed the impact of renewable generation on forecasting error, which could then be compared against the benchmark case without renewable generation.

Load Following Analysis Results

The forecasting error, including the scheduling error for each renewable resource of interest, was calculated. We compared the average minimum and maximum forecasting error during peak hours (noon to 6 p.m.) as a means of evaluating the significance of the renewable generator impacts. Minimum forecasting error was unchanged or slightly improved for all renewable resources. This means that renewable scheduling errors tended to reduce the magnitude of incremental energy purchases during peak hours. Maximum forecasting error was unchanged or slightly increased for all renewable resources. This means that renewable scheduling errors tended to increase the magnitude of decremental energy purchases during peak hours. These results appear in Table 3.

TABLE 3. IMPACT OF THE SCHEDULING ERROR OF EACH RENEWABLE RESOURCE ON THE FORECAST ERROR

	COMBINED FORECAST ERROR AND RENEWABLE SCHEDULING ERROR			
	Average Minimum		**Average Maximum**	
RESOURCE	MW	Compared to forecast error w/out renewables (%)	MW	Compared to forecast error w/out renewables (%)
Forecast error without renewables	-1909	100%	2220	100%
Biomass	-1897	99%	2218	100%
Geothermal	-1878	98%	2221	100%
Solar	-1870	98%	2220	100%
Wind (Altamont)	-1909	100%	2272	102%
Wind (San Gorgonio)	-1898	99%	2226	100%
Wind (Tehachapi)	-1884	99%	2281	103%
Wind (total)	-1870	98%	2377	107%
Scheduling bias	-5076	266%	1747	79%

Based on the results of this analysis, the impacts of renewable generators are small when compared against the bias introduced by the scheduling coordinators. As we discussed earlier, the scheduling bias provides an indication of the depth of the generator stack. Therefore, impacts that are small relative to the scheduling bias were not considered to significantly change the stack size or composition. These results indicate that renewable resources have no significant impacts on the stack at current levels of market penetration.

Load Following Analysis Recommendations

This preliminary analysis shows that there is no significant impact of existing renewable generators in the load following time scale. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are much less than the bias effects created by the scheduling coordinators. More detailed analyses are recommended to evaluate the effects of increased renewable penetration and impacts on load following reserves.

SUMMARY

These results are based on the California renewable characteristics of 2002. As newer facilities are installed with more advanced technology, we expect some of these impacts to change over time. However, we believe that the results of the Phase I study are robust and conservative for the near future. Table 4 summarizes some key results.

This study makes extensive use of actual data from the CAISO PI system. It therefore differs from several other studies that are more prospective in nature. Simulating wind plant output data can be challenging, but for this study we were able to collect a significant quantity of fast data from renewable generators and from other relevant system characteristics. Because of the tightly integrated nature of the power system and the tremendous aggregation benefits, a study such as this must necessarily do the analysis in the context of the system, rather than based on a single generator or type of generator.

The capacity value of wind depends on the timing of the wind power delivery relative to high-risk hours—those hours of significant system peak. As newer wind turbine technology is installed in the state, we expect that capacity values will improve relative to those we calculated for the existing wind turbine fleet. This is because of the improved performance characteristics of modern wind turbines—higher power output at lower wind speeds and air densities. We recommend additional reliability studies when this new technology is installed and data become available.

The regulation impacts of wind are small. This is not surprising, given the low correlation between wind fluctuations and load fluctuations on the small regulation time scale. (We note that some other studies may define regulation in a broader time scale than we do, leading to different results). The impact of higher wind penetration in the regulation time scale should be *less* than what we currently observe. Although this may run counter to intuition, adding additional uncorrelated signals will have a declining impact on the additional regulation needed to balance the system. As additional data become available, we will examine these impacts and update our results. It is important to properly interpret our results. Because of the data storage error for short-term variability inherent in the PI system, the actual numerical values cannot be treated with confidence. However, we *are* confident that the impacts that we've captured are approximately correct and that the regulation impacts on the CA system are small.

The load-following impacts of a relatively small penetration rate of wind in such a large control area are hard to measure. We examined detailed data from the ISO and found that the dispatch stack was considerably deeper than what would be required to compensate the system for the additional imbalance imposed by wind generators. In fact, we found that the impact of scheduling bias far outweighed any impact from any renewable sources. As additional wind is added to the generation mix, it will become important to update these results. As additional control technology is applied at both the individual wind turbine level and at the wind plant level, we expect that this will mitigate some of the additional impacts that might otherwise occur.

Wind is unlikely to become a source of contingency reserve requirements because of its relative size to other generators in the system and because wind output does not fall in a time scale that is short enough to be considered a contingency. However, reserves are held for other reasons, such as unanticipated increases in system load beyond what has been forecast. In our preliminary look at wind's impact on the dispatch stack, we found no evidence that additional ramping requirements caused by wind would come near exhausting the ramping ability of the system. As wind penetration rates increase, this issue should be examined further.

Finally, we note that this is but Phase I of a 3-phase study. We anticipate a broader retrospective analysis using 3 years of data. We also plan to examine these impacts under increasing penetration rates and newer generating technology.

TABLE 4. SUMMARY OF WIND RESULTS

	SUMMARY RESULTS BY WIND RESOURCE AREA			
RESOURCE	Capacity Value as Percent of Rated Capacity	Regulation Cost ($/MWh) (Negative number denotes cost)	Load Following: Increase (positive) or decrease (negative) in Maximum 1-hour Ramp Requirements (% of system)	Compared to forecast error w/out renewables (% of system)
Wind (Altamont)	26.0	0.00	0	2
Wind (San Gorgonio)	23.9	-0.46	-1	0
Wind (Tehachapi)	22.0	-0.17	-1	3

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13. ABSTRACT *(Maximum 200 words)* California's recently enacted Renewables Portfolio Standard (RPS, Senate Bill 1078) requires the state's investor-owned utilities (IOUs) to increase the renewable portion of their energy mix, with a goal of 20% renewable energy generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the California Public Utilities Commission (CPUC) establishing a process to select the "least-cost, best-fit" projects. The California Energy Commission (CEC), in support of the CPUC, organized a team to study integration costs in the context of RPS implementation. The analysis team, collectively referred to as the Methods Group, consists of researchers from the National Renewable Energy Laboratory and Oak Ridge National Laboratory and staff members from the California Independent System Operator, Dynamic Design Engineering, and the California Wind Energy Collaborative. This RPS Integration Study is motivated by the RPS's "least-cost, best-fit" bid selection criterion, which requires that indirect costs be considered in addition to the energy bid price when selecting eligible renewable projects. This paper summarizes the key results from the Phase I report. Specific issues examined in the report include capacity credit, regulation impacts and costs, and preliminary load-following impacts via the supplemental energy market in California. We also discuss the status of the RPS Integration Study and some implications for wind integration in other U.S. electric power markets.			
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