April 23, 2010

2010 Wind Integration Study
Public Comments on Project Method

On April 16, 2010 a Project Method paper was sent to public stakeholders for comments with responses due back on May 5, 2010. This document consists of the two sets of comments received from the following stakeholders, this document will be updated as comments are received:

- National Renewables Energy Laboratory
- Renewables Northwest Project

We appreciate our stakeholders who have provided comments on PacifiCorp's 2010 Wind Integration Study Project Method paper.

Regards,
PacifiCorp
IRP@PacifiCorp.com

A MIDAMERICAN ENERGY HOLDINGS COMPANY

2010 Wind Integration Study
Public Comments on Project Method Paper

From

National Renewables Energy Laboratory

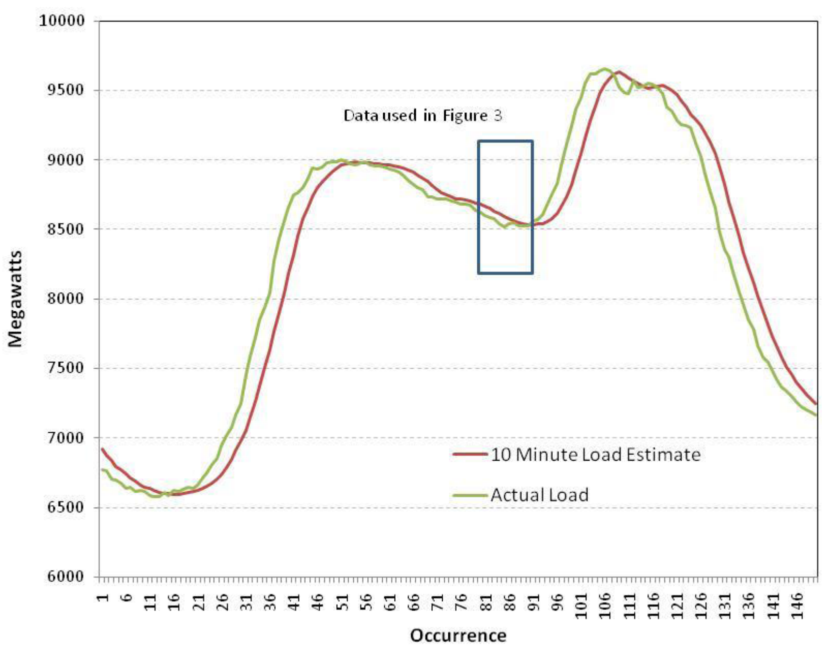
Comments on PacifiCorp Project Methodology for 2010 Wind Integration Cost Study (April 23, 2010)

Dear Mr. Warnken,

Thank you for providing the additional detail concerning the wind integration study methodology contained in the April 16, 2010 document "Project Method for 2010 Wind Integration Cost Study". The methodology is a great improvement over that use in the 2008 IRP. We offer the following suggestions to further clarify and improve the methodology.

Calculating Load Following and Regulation

The use of a rolling average to separate regulation and load following is one we and others have use. It is simple, robust, and appropriate. The exact equations are not provided, however, and it is not possible to tell if the method is being implemented correctly. Figure 2 appears to show an incorrect time shift between the rolling average and the actual load.



"Figure 2 A one-day plot of the rolling 60-minute average ten-minute estimate plotted against observed system load."

The rolling average should be centered on the actual data. That is, the rolling average should be an average of the 30 minutes before the interval and 30 minutes after the interval. The plot shows an average which is predominantly or completely before the interval. It is not possible to calculate the regulation burden unless the rolling average is balanced around the actual data.

Synthesizing Data for Future Wind Plants

The NREL WWSIS meso scale wind data set is still the best method for analyzing the integration impacts of future wind facilities and we encourage PacifiCorp to use that data set with time-synchronized loads. The PacifiCorp proposed method of synthesizing data based on time-lagged data from existing wind plants would work if wind always blew from the same direction, at the same speed, and remained coherent over long distances. Since wind does none of these things previous studies have found that time lagged synthesized wind data is not very good. It is very important in any event to scale the wind data correctly. It is inappropriate to use data from a wind plant of one size to generate data for a wind plant of another size.

Calculating Reserve Requirements

Page 2 states that operating reserve requirements will be "calculated seasonally for application in the production cost model". Wind reserve requirements should be applied based on the wind output. There is no need to carry additional up reserves when the wind is at full output. Similarly there is no need to carry down reserves when the wind is at zero. Load has a similar characteristic. Down ramping reserves are not required during the morning ramp up and up ramping reserves are not required during the evening ramp down. Applying reserves seasonally will greatly overstate the reserve requirements and result in incorrect production cost calculations.

Displace Generation can Provide Reserves

Because wind displaces other generation, there are times that the displaced generation can provide reserves. If there is enough capacity without wind to supply load, then there is enough capacity to serve load after wind is added to the generation mix, and there is some displaced conventional generation capacity. Therefore, one must be careful to not simply add additional reserves with wind. Wind will increase the ramping requirements on the system, and therefore a different *type* of capacity may be needed. It is not clear from the PacifiCorp document whether this has been taken into account.

Combining Regulation and Load Following

Page 6 states that regulation and load following will be combined into a single reserve capacity requirement. This is not appropriate. Regulation is a reserve requirement that should be carried throughout the production cost modeling time frames (though it should be adjusted based on the wind power output). Load following should be obtained from the economic movement of the energy supply generators. The load following capacity requirement should be checked each hour and the commitment adjusted only if the energy supply generators do not have sufficient ramping capacity that hour.

In the production simulation, the regulating reserve will never be explicitly used because the time resolution of the model is insufficient. However, the load following reserve can be used. This mimics actual system operation. If a given level of reserve is maintained in the load following time frame, and then the wind drops off unexpectedly, the model should be able to use the load following reserve when needed. Combining regulation and load following reserve would not allow for this.

Technical Review Committee

We continue to encourage PacifiCorp to make use of a full strong and independent technical review committee (TRC) under a UWIG charter. If time does not permit the use of a TRC for this study then some type of public forum should be used to obtain feedback. In any case, PacifiCorp should use a TRC for the next study.

Thanks you for your consideration

Brendan Kirby, P.E., NREL Consultant

Dr. Michael Milligan, NREL

2010 Wind Integration Study
Public Comments on Project Method Paper

From

Renewables Northwest Project

Renewable Northwest Project

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Renewable Northwest Project

April 23, 2010

Pete Warnken
PacifiCorp
825 NE Multnomah
Portland, OR 97232

Dear Mr. Warnken,

Renewable Northwest Project (RNP) appreciates the greatly improved methodology proposed in the recently released "Project Method for 2010 Wind Integration Cost Study" paper. Attached is a redlined version of this paper containing RNP's specific comments and edit suggestions. In general, we note that the proposed methodology appears to be generally consistent with best practices. Noted in the attachment are areas that we feel need greater clarification, components that we feel are in error as proposed or that could be improved.

We summarize the main points of the redline below, but very briefly, our main issues are:

1. Development of wind generation data—the proposed procedure needs additional explanation, and we propose an alternative to produce wind generation data based on the NREL data set, calibrated to PacifiCorp's observed historical data where available.
2. Nonstandard definitions of "Regulation" and "Following" that may lead to confusion.
3. Intra-hour variability should be the difference between an unbiased schedule for the hour, not a 60 minute average (and especially not a trailing average).
4. How inter-hour reserves are used in the PaR model and the need to ensure that inter-hour reserves can be dispatched by the model.
5. Lack of detail on exactly how costs associated with the various PaR model runs get turned into integration costs for use in the IRP process.

A major challenge in producing wind integration studies is the development of wind generation data for projects that are not currently in operations. While the proposed methodology appears to be a significant improvement over the prior method, we suggest a slightly revised version of the methodology that would rely on a combination of the NREL wind data set and historical observations, but likely result in a more realistic representation of wind data from projects for which historical data is unavailable.

The nomenclature concern we have is the seemingly non-standard use of "Regulation" and "Following" reserve components. PacifiCorp's proposed definition of "Regulation" corresponds to Bonneville Power Administration's (BPA) definition of "Following", and PacifiCorp's definition of "Following" corresponds to BPA's "imbalance" reserves. We feel that the BPA definitions are more standard and urge PacifiCorp to consider using the more standard terminology to avoid confusion.

In the attached redline, we raise some technical issues with respect to how "Regulation" reserves are proposed to be calculated, suggesting a different method consistent with the BPA rate case methodology more appropriate to western markets where there is no intra-hour dispatch or trading.

We point out that care must be taken in specifying reserves to the PaR model, likely necessitating leaving out the "Following" reserves in at least some model runs so that reserves held to balance wind generation are actually available to the model dispatch logic.

The proposed methodology is apparently silent on exactly how the model runs will translate to costs relevant to a 20-year horizon Integrated Resource Plan (IRP) analysis. We urge PacifiCorp to fill in the blanks to leave a clearer understanding of how the model results will be used to supply wind integration costs to the IRP study.

Again, we appreciate the much-improved approach to undertaking a wind integration cost study as represented by the latest paper. We do hope that there continues to be flexibility in adjusting the methodology to reflect best practices where possible, and that the comments provided here are helpful.

Sincerely,

Ken Dragoon

Ken Dragoon
Research Director
Renewable Northwest Project

Project Method for 2010 Wind Integration Cost Study

Introduction

Traditionally, load and generation are balanced using dynamic operations in a straightforward manner – load is uncontrollable and variable, and generation is dispatched subject to its dispatch limitation (be it hydro, thermal, or other sources) to match variable load. The advent of wind generation in substantial amounts has introduced a new variable to the operation of power systems; sizable, nondispatchable generation.

The total installed capacity of wind generation in PacifiCorp's balancing authority areas (east and west) in 2000 was 33 MW. As of April 2010, there is approximately 1,400 MW, or roughly 10% of the total installed capacity on the system. By 2017, it could be more than 2,200 MW. Given the growth of wind in PacifiCorp's portfolio, it is increasingly important to understand its impact on the overall operations of the system. While there are costs and operational challenges associated with large scale wind penetration, there are also benefits, which would include a cleaner energy resource mix and fuel diversification for customers.

To understand the costs of integrating wind, this paper contemplates the analysis and valuation of operational changes required to manage variable wind generation at different levels of penetration while maintaining reliability. The approach outlined herein will be used to estimate the amount of Operating Reserves (power generation plants operating on less than full or variable capacity with flexible output capabilities) needed to manage fluctuations in load and fluctuations in wind within PacifiCorp's balancing authority areas. The Operating Reserves discussed here are limited to Spinning Reserves and Non-Spinning Reserves; and the flexible services provided are broken into Regulation, Load Following, and Contingency. For purposes of this paper, Regulation refers to variability of load and wind generation output managed within ten minute real timeframes, and Load Following represents the variability as measured in hourly real timeframes. Contingency reserves, although mentioned, are supplied in accordance with WECC standards.

Once the amount of Operating Reserves is established for different levels of wind penetration, the cost of holding these reserves on PacifiCorp's system will be calculated using the Planning and Risk (PaR) model. In addition to using PaR for evaluating Operating Reserve costs, the PaR model will also be used to estimate wind integration costs associated with day-to-day rebalancing of the system. These system balancing costs result from the unpredictable nature of wind generation on a day-ahead basis and can be characterized as

Comment [KD1]: Note that re-balancing the system on a day-ahead basis should reduce the amount of presumably more expensive hour-ahead transactions, reducing the overall integration costs. There are potentially equivalent costs associated with day-ahead gas nominations for gas plants (ie, errors in day-ahead estimates of the spark spread), and unless PacifiCorp is planning to add similar "integration costs" to its gas facilities, it needs to tread lightly here.

system costs born from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions. These services are compared to the Wind Integration Cost terms in the 2008 Integrated Resource Plan update in Table 1:

Table 1. Index of new Wind Integration Cost components to components previously published in the Pacificorp 2008 IRP, Appendix F.

2008 IRP Description	Methodology Description
Day Ahead Forecast Variaton	System Balancing
Hour Ahead Forecast Variaton	
Actual Forecast Variation	Load Following
Regulate Up	Regulation
Regulate Down	

Comment [KD2]: Not clear what "Actual Forecast Variation" means. Also not clear why incremental and decremental reserves (Reg Up and Reg Down) are identified for "Regulation" but not for "Load Following".

Method

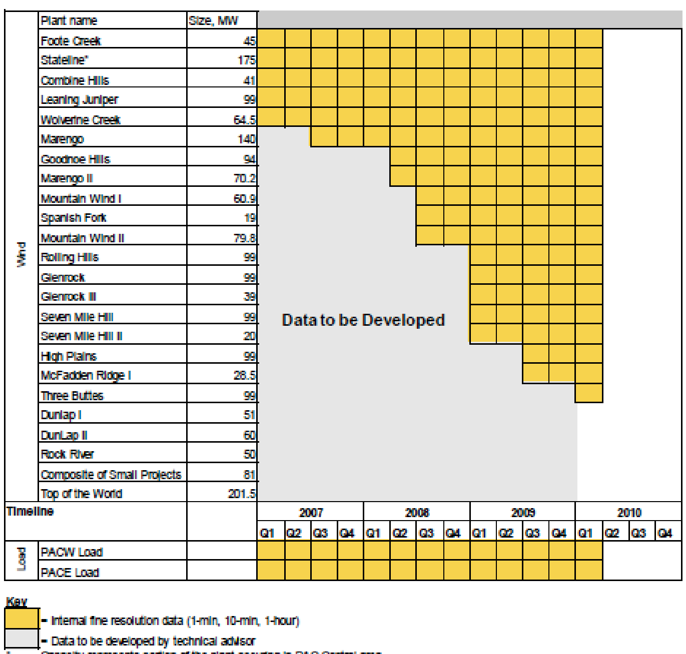
In analyzing the effect of wind generation on PacifiCorp's system operations in the east and west balancing authority areas, the analysis team has two key objectives:

- Beginning with wind generation and load data, apply current power system operational practice to develop a methodology for estimating how wind generation would affect the need for incremental physical Operating Reserves for PacifiCorp's system under a set of wind capacity penetration scenarios.
- Use existing production cost models to isolate the cost of holding incremental Operating Reserves and to establish costs for system balancing created by day-ahead forecast errors associated with load and wind generation.

The first objective focuses on the alteration of the physical Operating Reserves position estimated in ten-minute and hourly timeframes, and will be calculated seasonally for application in the production cost simulations. The second objective represents the key stage of the analysis, for it will not only evaluate the cost of the marginal reserves position established to manage the wind position in real time, it will also assess costs resulting from wind variability in the day-ahead timeframe. In other words, each hour features a need to set aside increased Operating Reserves (both spinning and non-spinning reserves), in addition to those set aside explicitly to cover load and contingency events which are inherent to the PacifiCorp system with or without wind. The cost to hold additional hourly operating reserves can be calculated in the production cost simulation, as can the system cost of day-to-day rebalancing induced by the unpredictable nature of wind generation on a day-ahead basis. Estimation of such rebalancing costs will be achieved by allowing the PaR model to establish unit commitment choices under a forecast of wind, while being faced with dispatch decisions against actual system conditions. In aggregate, the cost of holding reserves and the cost of rebalancing will produce an estimate of the wind integration costs specific to PacifiCorp's system.

<u>Calculating Incremental Operating Reserve Requirements</u>
PacifiCorp makes the calculation for existing Operating Reserve requirements starting with load and production data for the 2007-2009 period (the Initial Term), as represented by Figure 1. Both the load and generation data are available on ten-minute intervals for the Initial Term. PacifiCorp chose to use this data because it represented the best base of observed data available within the company, which includes significant concurrent load and wind generation data, and includes more than just one year's variation of weather and other affective variables on load.

Figure 1. Historical production and load data available to PacifiCorp Wind Integration study.



The figure also contemplates the unavailability of certain wind data germane to the study. PacifiCorp desires to use as much real, observed, concurrent data as possible, owing to the very unpredictable nature of wind generation output as well as the many fine variations available in real load data not always found in simulated data. As a result, the technical advisor procured by PacifiCorp to assist with the study, The Brattle Group, will fill in the missing wind data pertaining to the Initial Term by using statistical methods and simulating the needed wind data where historical observed data is unavailable or insufficient. The Brattle Group is currently developing the specific methodology necessary to derive the statistical parameters that describe the wind variability from the available wind data and through those statistical parameters, simulate the wind data.

Broadly, the missing wind data can be segmented into two groups. The first group consists of wind sites for which partial data is available and the second group consists of wind sites for which no historical data is available. Based on the map of the wind farms locations in the PacifiCorp's service areas,[1] it appears (and we assume) that in both the PacifiCorp's East and West control areas, at least one or more wind sites is located in close proximity to sites with partial or no historical wind data.

In the discussion to follow, W_{pd} refers to a wind site with incomplete/partial data available, W_{fd} refers to a wind site with full data availability, and, W_{nd} refers to a wind site with no historical data available.

To simulate the wind data for sites W_{pd} (partial historical data available), Brattle proposes to perform the following steps: First, *Brattle* estimates an econometric model that quantifies the relationship between data from a W_{fd} wind site and data from a nearby W_{pd} site. Effectively, the data from W_{fd} would be used as a predictor of the W_{pd}, or the site with partially-available historical data while preserving the temporal relationship between the two data sets and controlling for various measures of seasonality (time of day, season of year, etc.).

Second, Brattle would use the resulting estimated coefficients in the regression model to apply to the remaining data from W_{fd} to simulate values for W_{pd} over the missing period. Since those predicted values for W_{pd} will be estimates of the mean values, an addition of stochastic noise will be used to augment the simulated wind generation values. Using the augmented predicted values, the regression will be estimated again over the full period, resulting in a new set of regression coefficient estimates. This full regression estimation

Comment [KD3]: Not clear whether this refers to generation or wind speed at a project. If it represents generation, then there are issues with the ensuing discussion because the analysis does not contemplate adjustments for project size that are relevant (ie, larger projects are less variable on short time scales than smaller ones). If it relates to wind speed then there is a missing task relating to translating wind speed to wind generation that also needs to take into account project size.

Comment [KD4]: I think this whole methodology would be better if econometric models were developed that map the NREL meso scale data to your historical wind generation (where available), and use those relationships, or at least those kinds of relationships to apply to sites where data is sparse or non-existent. The process would be almost the same as here, except that the predictive variables would be the NREL data for the site locations, and missing data would be the econometric parameters...

[1] Map provided available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/12-35_PC_RenewableEnergyFlyer.pdf

process will be repeated until there is a convergence in the regression estimates. This approach is a simplified version of the Expectation Maximization (EM) algorithm. The specification of the regression model would need to be developed through an exploratory process of the available data set. It is likely that the model will be a variation of a distributed lag specification to represent the dynamics of wind generation.

Third, a simulated profile will be generated for the missing period, which, in addition to the partially available actual data, will result in a complete wind profile over the time period of interest for a W_{pd} site.

To simulate the wind data for sites where no historical data is available, Brattle will rely on existing data for a nearby site W_{fd}. Given the increased complexity of this task (compared to filling a partially available data set), the general approach described here might require adjustments, particularly by supplementing the econometric assumptions and techniques to reach converging results. The approach proposed for simulating wind data where no historical data is available assumes that once we establish a relationship between two full profiles that are part of two groups of wind sites located in two distinct areas, the relationship is representative for corresponding pairs of wind sites from those two geographic groups.

The steps would involve the following: If an area **A** has at least one wind site with full dataset (W_{fd_areaA}) located in proximity to the site with no historical data (W_{nd_areaA}), we would estimate a regression model using (W_{fd_areaA}) as a dependent variable. The explanatory/independent variables in this regression would come from the distributed lags of another full data wind site in a different area, **B**, (W_{fd_areaB1}). Having obtained the estimated regression coefficients, we would apply those coefficients to data from a third wind site that has a full data span and is also located in area **B** (W_{fd_areaB2}) to estimate data for output from W_{nd_areaA}. Then, a properly distributed stochastic noise would be added to simulate the wind data for W_{nd_areaA}. W_{fd_areaB2} could be a wind site that had a pre-existing full data set available or a site with partial data set for which we previously had estimated a full-period wind profile (as outlined in the EM algorithm approach above).

For those wind generation sites where there is no data available in the Initial Term, the Brattle Group will generate the missing data by using production estimates generated in the project review to seed the back-simulation.

Once a dense data set is created, the interval data drives the calculation of the marginal reserves requirement in two components; *Regulation*, which is developed using the ten-minute interval data, and *Load Following*, which is calculated using the same data but estimated using the hourly variability.

Comment [KD5]: This needs to be defined more clearly, preferably with an example. It is unclear whether this methodology is appropriate to developing massive quantities of missing data such as appears to be proposed here. For example, is it contemplated that 36 months of data will be reconstituted based on three months available for the Three Buttes Project, and is that appropriate?

Comment [KD6]: It is unclear what "distributed lags" means. The best fit lag between two projects is not constant through time, and it would be appropriate to constitute a distribution of lag times between projects to apply, but it is not clear that is meant here. In any case, it is not appropriate to use single, fixed lag times to represent the relationship between projects—the problem being the introduction of too much correlation between projects and schedule errors over periods larger than the lag times.

Comment [KD7]: This definition of "Regulation" seems to represent the variability of ten minute averages around a 60 minute average—not the more common notion of regulation as generation responsive to more rapid changes on the order of minutes or seconds.

Comment [KD8]: Again, this definition seems more consistent with what BPA called imbalance reserves (hour-long bias between schedules and observed load/wind), and what you call regulation is what BPA called following… it would be helpful to use consistent language, or at least point out the correspondences with other usages.

Regulation and Load Following

The approach for calculating incremental Operating Reserves necessary to supply adequate capacity for regulation and load following at levels required to maintain current control performance was based on merging current operational practice with a survey of papers on wind integration, as well as advisory from the Brattle Group. PacifiCorp will employ Initial Term (2007-09, inclusive) load data as the baseline case (zero wind generation) in each scenario. Coincident wind data (as observed, plus that generated by the Brattle Group per Figure 1) will be added in increasing levels of wind penetration capacity to gauge the change in operating reserves demand. For purposes of this study, the Regulation calculation compares observed ten-minute interval load and wind generation production to a ten minute interval estimate, and Load Following compares observed hourly averages to an average forecast. The determination of Regulation and Load Following reserve capacity requirements, and their combination into a single reserve capacity position may be done seasonally, and is discussed in detail below.

Regulation

With no sub-hourly clearing market, PacifiCorp must meet sub-hourly load (and load net of wind) deviations with system resources. This includes automatic generation control (AGC), demand side management (DSM), and the ramping of flexible generation units in real time operations, which represents a draw on Operating Reserves. Wind variability among ten-minute intervals can represent a quantity of generation required to ramp up or down to maintain system stability. To parse the ten-minute interval variability from the ensuing load following analysis, a persistence forecast of the rolling prior 60 minutes will be used to analyze the variation of each ten minute interval. The actual load in each ten minute interval will be subtracted from the rolling average of the prior 6 ten minute intervals, and the standard deviation will be computed for each seasonal period. This approach follows the one used by the National Renewable Energy Laboratory (NREL) for its recent "Eastern Wind Integration and Transmission Study.[2]

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Comment [KD9]: This quantity should be determined from the difference between observed values and a perfect schedule (not a "ten minute interval estimate"), especially so since the Following component takes account of the differences between observations and schedules ("forecasts")

Comment [KD10]: This should not be a generic "forecast" but a schedule prepared for wind and load that includes ramping between operating hours.

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Comment [KD11]: Again, the comparison should not be made to a 60 minute rolling average, but a perfect (zero imbalane) schedule for the hour. It made sense for NREL to do what it did because that analysis did not assume hourly schedules and no intra-hour dispatch such as we have here in the west. It appears from Figure 2 that the rolling average contemplated is a trailing 60 minute average, and that introduces an additional error.

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[2] NREL, *Eastern Wind Integration and Transmission Study*, prepared by EnerNex Corporation, (January 10, 2010), p. 143. The report is available for download from the following hyperlink: http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

$$\sigma_{Wind10min} = \sqrt{\frac{1}{N}\sum_{1}^{N}(Wind_{Rolling60} - Wind_{Actual10min})^2}$$

Comment [KD12]: Formula should substitute perfect schedule for the Rolling60 variable.

Where:
N *= number of ten-minute intervals in the period*
Wind*Rolling60* *= the rolling average of the wind generation in prior 6 ten minute intervals*
Wind*Actual10min* *= the observed wind generation for a given ten minute interval*

Similarly, the load variability is also analyzed with the actual ten-minute interval load being subtracted from the rolling sixty minute average.

$$\sigma_{Load10min} = \sqrt{\frac{1}{N}\sum_{1}^{N}(Load_{Rolling60} - Load_{Actual10min})^2}$$

Comment [KD13]: Formula should substitute perfect schedule for the Rolling60 variable

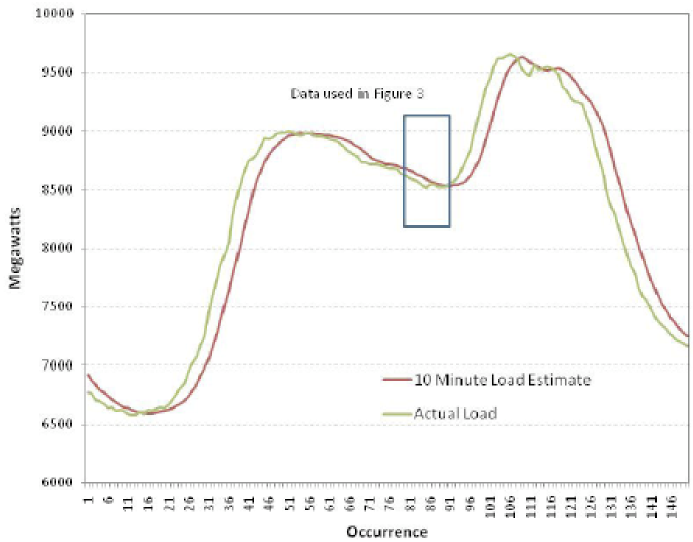
As the ten minute load and wind errors each represent unpredictable change in the need for dispatchable generation, their variability can be assessed separately and combined. The standard deviation of load net wind generation, which is the basis for the regulating reserve, can be computed assuming fast variations in load are not correlated with changes in aggregate wind generation output:

$$Regulation_{10min} = \sqrt{\sigma_{Load10min}{}^2 + \sigma_{Wind10min}{}^2}$$

Comment [KD14]: This formula is not correct—the left hand side should be a sigma that is related to (but not equal to) the 10 min reserve requirement.

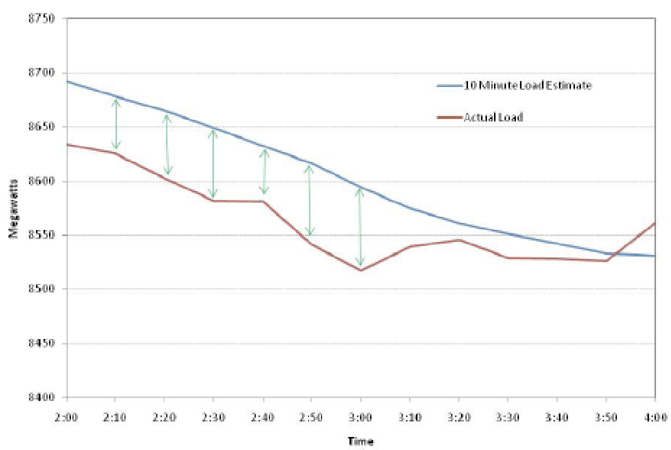
Figures 2 and 3 illustrate the difference between observed ten minute interval load and wind data from the rolling average.

Figure 2. A one-day plot of the rolling 60-minute average ten-minute load estimate plotted against observed system load. The data used for Figure 3 is highlighted.



Comment [KD15]: This figure appears to suggest a lagging 60 minute average—again, the comparison should be with a perfect (zero bias) schedule for each hour that includes ramps between operating hours.

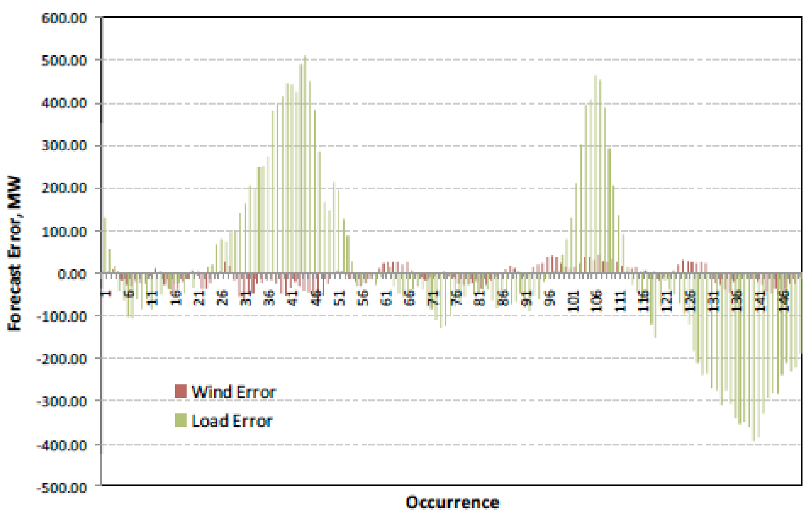
Figure 3. Highlighted data showing variability between ten-minute persistence forecast and observed load. Several example errors between the estimate and actual data are highlighted with green arrows.



Comment [KD16]: The variability depicted by the arrows in this diagram are primarily an artifact of using a lagging average. The actual 10-minute variability would be (roughly) the variability about an average for the current hour. The proposed methodology would double count some of the reserves determine in this way with the "following" reserve methodology.

The errors logged for the same day, for load and wind, are represented in Figure 4. The independence of the wind from load, as well as the relatively small contribution of wind generation to the net error is evident.

Figure 4. Independent errors in short term load forecast and wind generation used to assess the regulation position. The data in this figure comes from December 2008, and so reflects only roughly 6% wind capacity penetration.



Comment [KD17]: Assume each data point represents 10 minutes? Would be good to label the axis.

Load Following

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In addition to the short interval services provided by Regulation described above, PacifiCorp maintains balance on its system by optimizing its operations to an hourly forecast with changes in generation and market activity. This planning interval represents hourly changes in generation which are assessed within roughly 20 minutes each hour to account for a bottom-of-the-hour (:30 after) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demands with an expectation of how much higher or lower system load (net of wind generation) may be.

Hourly Forecasting

PacifiCorp's real-time desk updates the next hour's system load forecast forty minutes prior to each operating hour. This forecast is created by comparing the current hour load to the load of a similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load delta) is applied to the current hour load and the sum is used as the forecast for the ensuing hour. For example, one a given Monday the PacifiCorp operator may be forecasting hour to hour changes in system load by referencing the hour to hour changes on the prior Monday, a similar-load-shaped day. If the hour to hour load change between the prior Monday's like hours was 100 MW, the operator will use a 100 MW change in load as the next hour forecast.

While operational short term wind forecasting includes qualitative analysis in assessing the wind generation, the 20th minute persistence forecast is what can be quantitatively modeled at this time, and is a reasonable approximation of operational practice. As modeled here, hourly wind forecasting is done by persistence; applying the instantaneous sample of the wind generation output 20 minutes past the current hour to the next hour as a forecast and balancing the system to that point.

The resulting operational process therefore goes as follows; at the top of the hour, wind generation output, dispatchable generation output, and load values are summarized, and trended using the methods above. The result is compared to the next hour's schedule for gaps as soon as possible, with the generation and load values updated at roughly the 20th minute past the hour. This result is then balanced through a combination of market transactions and scheduling adjustments to PacifiCorp resources to produce a balanced schedule for the ensuing hour, with all transactions having to be complete by the 30th minute past the hour. For purposes of the calculation made in this exercise, the hourly wind forecast will consist of the 20th minute output from the prior hour, and the load forecast will be modeled per the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules.

Analysis

Using the Initial Term data for PacifiCorp's balancing authority areas, a comparison of the load and wind forecasts will be implemented to measure the seasonal or annual trends in the variability between the hourly interval load and wind forecasts and the observed average hourly load and wind generation values. These differences will be culled into bins by load magnitude (or by load magnitude and wind generation magnitude) using load and wind data. An example of load data segmented into bins appears in Figure 5. With probabilities implied by the population of each bin, representing the expected amount of time spent in each load state, as represented by the historical data alone. The percentile equivalent to the historical Control Performance 2 (CPS2)[3] performance of PacifiCorp will be sampled above and below the median of each of the bins. The average CPS2 performance for PacifiCorp's east and west balancing authority areas is just below 97%. As the goal of this method is to incorporate wind integration in PacifiCorp's current operations, the CPS2 target of 97% will be

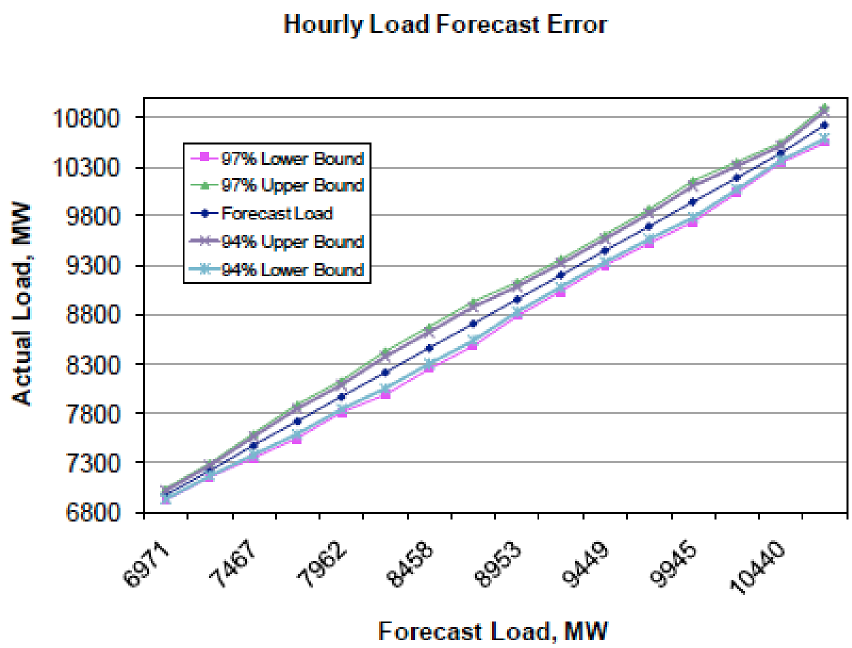
Comment [KD18]: Seems like a high target—can we test 95% too?

[3] The Control Performance 2 is a reliability standard is maintained by the North American Electric Reliability Council. A definition is available on page 3of the document at the following hyperlink: http://www.nerc.com/files/Reliability_Standards_Complete_Set_2010Jan25.pdf

emphasized in these calculations. Indicative incremental reserves changes can be calculated for varying target CPS2 scores. However, overall system power quality is a much larger issue than simply of wind integration. The difference between the CPS2 percentiles and the median of the bins will represent the implied incremental Operating Reserves position within that bin. This reserves position will be adjusted downward by the system L_{10} for the each balancing authority area, as defined by NERC[4][5]. As each respective bin will also have an implied probability by the number of data points falling within it, averaging the volumetric position over the study period will be a simple matter of integration.

Comment [KD19]: I don't know what "volumetric position" means in this sentence—volume of wind generation, reserves....???

Figure 5. Example graph of bin analysis for load following reserve for system load. Note the state variable is system load, and the reserves required are the difference between the upper and lower curves about the median. CPS2 targets of 97% and 94% are presented for comparison to illustrate sensitivity to the CPS2 score targeted.



Comment [KD20]: It isn't clear whether this represents a year, or some season. We welcome the idea of holding different level of reserves depending on a current level of load, but the current state of wind generation is also relevant. See Idaho Power Company's wind integration study—reserve levels were adjusted depending on the joint state of wind and load. Another thing to consider is that the load-related reserves may be more dependent on time of day than on absolute level of the load. For example, reserve levels are probably highest during morning and evening ramps than during the highest and lowest load hours. Conditioning reserves on time of day (and wind) may be more important than conditioning on level of load.

[4] The L10 standard is a reliability standard component maintained by the North American Electric Reliability Council. A definition is available on page 1 of the document at the following hyperlink: http://www.nerc.com/files/Reliability_Standards_Complete_Set_2010Jan25.pdf

[5] The L10 for PacifiCorp's east and west balancing areas os 49.53 MW and 36.92 MW respectively.

Per the illustration in Figure 5, the Load Following reserves position for the bin centered on a system load forecast 8,458 MW would be calculated by subtracting the lower bound value (roughly 8,244 MW) from the upper bound value (roughly 8,671 MW) for an estimate of 427 MW. Subtracting a hypothetical system L_{10} of 50 MW (doubled to account for its bidirectional nature), yields a reserves requirement of 327 MW for the load state defined by 8,458 MW of system load. Integrating this process through each bin will yield a composite position for the system control area. Wind generation can be analyzed in exactly the same procedure, but with generation output representing the individual state variable. As per the Regulation calculation, the wind and load reserves positions would be combined using the root sum square calculation, assuming their variability in the short term is independent.

$$Reserves_{LoadFollowing} = \sqrt{\sigma_{LoadReserves}{}^2 + \sigma_{WindReserves}{}^2}$$

Operating Reserves Capacity Allocation

The method used to price the expense of maintaining additional Operating Reserves for increased wind penetration in this study ~~using~~ uses(?) a production cost simulation, which dispatches plants hourly against load simulation with an assumed wind generation profile. Given the hourly-only granularity of these computations, and the fact that real-time operations must deal with sub-hourly variations, many details of real-time operation cannot be simulated in the production cost model, which may underestimate the cost of additional Operating Reserves. In this method, the most granular approximation of these services is the ten-minute interval calculation for Regulation. Given the limitations inherent in the data available, it is understood that other costs may be determined later to cover the expenses required to maintain this additional flexibility.

Another key feature of the production cost modeling is the requirement to separate Spinning Operating Reserves from Non-Spinning Operating Reserves.[6] [6] Similar to the approach used for the NREL Eastern Wind and Transmission Integration Study, PacifiCorp breaks out the service of the reserves position as follows in Table 2:

[6] Spinning Operating Reserve is defined as unloaded generation which is synchronized, ready to serve additional demand and able to reach reserve amount within 10 minutes. Non-spinning Operating Reserve is defined as unloaded generation which is non-synchronized and able to reach required generation amount within 10 minutes.

Comment [KD21]: Incremental and decremental reserves should be calculated separately. The distributions tend not to be symmetric—BPA holds 25% more decremental generating capability than incremental capability to meet similar probability of exceedence levels. This is because widespread wind ramps tend to occur with more severity up than down, presumably because the leading edges of weather fronts tend to be more organized than the trailing edges.

Comment [KD22]: This formula too is not literally correct. The standard deviation of load following requirements is equal to the right hand side, not the reserve level itself. The reserve requirement is likely between twice and three times the quantity on the right side of the equation.

Reserve levels should be picked from the appropriate percentile levels of the joint distributions of the load/wind differences as discussed above Figure 5 and depicted in the figure.

Comment [KD23]: I couldn't quite make sense of this sentence as written… not sure I captured it with the edit.

Comment [KD24]: This seems like an open-ended place holder for adding costs in later. It makes sense that there is an opportunity cost for holding (and potentially acquiring) reserves, and also for operating those reserves. We would prefer that this be more specific about any types of costs that are not anticipated to be captured using the proposed methodology.

Table 2. Allocation of Reserve Capacity to spinning and non-spinning positions for production cost modeling.[7][8]

Reserve Service	Spinning Operating Reserve	Non-Spinning Operating Reser
Regulation	4 * (Regulation$_{10Min}$)	0
Load Following	0.5*(Load Following Reserves)	0.5*(Load Following Reserves)
Contingency	0.5*(5% of Hydro + 7% of Thermal generation output)	0.5*(5% of Hydro + 7% of Thermal generation output)
Total	Sum of the above	Sum of the above

Comment [KD25]: Would like to know where the factor of 4 comes from for "Regulation".

The formula for "Contingency" omits wind generation—presumably contingency reserves are held against 5% of wind generation on any given hour.

Allotting the seasonally calculated reserves differential (under *Regulation* and *Load Following* sections above) results in a seasonal or annual schedule of additional spinning and non-spinning operational reserves required for the studied wind penetration level, ready to incorporate in PacifiCorp's Planning and Risk (PaR) model, which calculates the production costs resulting from each wind penetration scenario, as described in the following section.

Comment [KD26]: Again, wonder whether holding reserves dynamically by time of day should be/will be considered.

Production Cost Modeling

PacifiCorp's PaR model, developed and licensed by Ventyx Energy LLC, uses the PROSYM chronological unit commitment and dispatch production cost simulation engine, which commits and dispatches the thermal resources by looking ahead for a week at a time. The Company will use the PaR model in deterministic mode to estimate the two types of wind integration costs contemplated in this study – wind integration costs associated with Operating Reserves and wind integration costs associated with system balancing. The former reflects integration costs that arise from short-term (within the hour and hour ahead) variability in wind generation and the latter reflects integration costs that arise from errors in forecasting wind generation on a day-ahead basis. Both types of wind integration costs will be estimated under a range of wind penetration scenarios as identified in Table 3.

7 The multiplier on Regulation services is consistent with previous studies and background information provided by Oak Ridge National Laboratory, per *Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio*, p.49.

8 Contingency Reserves are specified by the Western Electricity Coordinating Council in per http://www.nerc.com/files/BAL-STD-002-0.pdf .

Table 3. Wind Penetration (on a Capacity Basis) scenarios planned for production cost analysis.

Representative Timing	Baseline	EOY 2007	EOY 2009	EOY 2011
Installed Wind Capacity	0	400	1400	1750
Wind Penetration	0%	3%	10%	12%

Comment [KD27]: Are you planning to look at the three historical years of wind/load (2007-9) at each of these levels of development? Are other assumptions anticipated to change for these test years, such as market prices?

Calculating Operating Reserve Wind Integration Costs

PacifiCorp's Initial Term data will serve as the basis for estimating the cost of Operating Reserve wind integration costs, and the calculation period will cover the 2011-13 forecast period (the Term) using the Company's 2010 business plan resource portfolio.[9] This calculation method aims to combine the benefits of using actual system data available for the three year period defined by the Initial Term with current forward price curves pertinent to setting the cost for wind integration service (including Regulation and Load Following services described above) on a forward basis.

Comment [KD28]: This is a welcome change from the previous analysis which appeared to assume a 20-year level of wind development throughout the study period. However, the present analysis is an IRP analysis with a 20 year study horizon—I don't see how the costs developed for the different penetration levels is proposed to be applied to each of the years in the study horizon.

To assess the effects of various levels of wind capacity added to the balancing authority areas, each of the penetration scenarios will be simulated in PaR using both *ideal* and *actual* wind profiles.[10] Simulations with the ideal wind profile assumes all the wind energy is delivered in a shaped profile having the same amount of energy as the actual wind profile, but without hour-to-hour variability that defines actual wind generation. Such a profile would require no additional operating reserves to support wind generation variability, and as such, the PaR simulation will only be required to hold Operating Reserves consistent with load variability. The actual wind profile will reflect the 2007-09 observed and developed wind data in accordance with the data section above. These actual wind profiles will contain the variability used to derive the incremental Operating Reserve requirements, and consequently, the incremental reserve demand will be input into the PaR simulation. In both the ideal and actual PaR simulations, we will assume there is no day-ahead forecast error. The system cost differences between these two simulations will be divided by the total volume of wind generation contemplated for each penetration scenario to derive the wind integration costs associated with having to hold incremental Operating Reserves.

Comment [KD29]: It would be correct to put the "Regulation" reserves into PaR as reserve requirements, but you have to be very careful putting the "Following" reserves into the model as a reserve requirement. The model needs to be free to dispatch "reserves" held for hourly dispatch needs, and most models will not allow dispatch of reserves.

Comment [KD30]: If the point of this is to isolate the opportunity costs of holding the reserves as distinct from the operating costs associated with the incremental variability, the two model runs should be the ideal study as proposed, and the same study with all the reserves (both following and regulation) held out. In this way the following reserves won't be duplicatively needed to be dispatched to meet wind variability.

9 The 2010 business plan resource portfolio and its derivation are documented in the 2008 Integrated Resource Update report, filed with the state utility commissions on March 31, 2010. The report is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf

10 At least one high-end wind capacity penetration scenario will be simulated, which will be defined after preliminary portfolio development for the 2011 Integrated Resource Plan has been completed.

Calculating System Balancing Wind Integration Costs

Another series of PaR simulations will be completed to estimate day-to-day system balancing wind integration costs consistent with the wind penetration scenarios identified in Table 3. In this phase of the analysis, PacifiCorp generation assets will be committed consistent with a day-ahead *forecast* of wind and load, but dispatched against *actual* wind and load. To simulate this operational behavior, two PaR runs are necessary for each scenario. The first PaR run determines the unit commitment state of generation assets given the forecast of wind and load. The second PaR run uses the unit commitment state from the first PaR run, but dispatches units based on actual wind and load, which will be identical to the actual wind and load inputs used to derive Operating Reserve wind integration costs as described above. In both PaR simulations, the amount of incremental reserves required for each penetration scenario will be applied. The change in system costs from this second PaR simulation as compared to the system costs from the *actual wind* simulation already produced in the estimation of Operating Reserves will isolate the wind integration cost due to system balancing. Dividing the change in system costs by the volume of wind in each penetration scenario will yield system balancing integration costs on a $/MWh basis. Table 4 summarizes how the various PaR simulations will be structured.

Comment [KD31]: Again, the following reserves should not be put into PaR unless PaR has a way of releasing them as needed to meet load net of wind demand.

Table 4. PaR simulations that will be completed for each wind penetration scenario.

PaR Simulation	Forward Term	Load	Wind	Incremental Reserves	Day-Ahead Forecast Error
1	2011 - 2013	Initial Term - Actual	Initial Term - Perfect Shape	None	None
2	2011 - 2013	Initial Term - Actual	Initial Term - Actual	Yes	None
3	2011 - 2013	Initial Term - Day Ahead Forecast	Initial Term - Day Ahead Forecast	Yes	None
4	2011 - 2013	Initial Term - Actual	Initial Term - Actual	Yes	Yes (Commitment from PaR Simulation 3)

Operating Reserve Integration Costs = system costs from PaR simulation 2 less system costs from PaR simulation 1.
System Balancing Integration Costs = system costs from PaR simulation 4 less system costs from PaR simulation 2.

Comment [KD32]: To summarize from before, PaR Simulation 2 should use "Perfect Shape" in the "Wind' column. Simulations 3 and 4 should not include "Following" reserve requirements.

Total integration costs for a given Forward Term will be the cost difference between Simulations 2 and 1, plus the difference between Simulation 4 and 3. These costs will be averaged over the three years of the Initial Term (2007-9) historical wind/load period. Levelized costs over the term of the IRP horizon will be computed by ????

Comment [KD33]: It is important to say how the total costs will be computed—what I wrote here is what I think you meant, but it should be made explicit, especially if I have gotten it wrong. Also, we do need some notion of how the costs for the three Forward Term years will relate to what is intended to be used for the IRP.