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May 19, 2009

Tracy Kirkpatrick
Administrative Law Judge
Public Utility Commission of Oregon
550 Capitol St NE – Suite 215
PO Box 2148
Salem OR 97308-2148

Re: UM 1368 – Submission from the Oregon Independent Evaluators (Boston Pacific)

Dear Judge Grant:

On May 18, 2009, Staff filed a highly-confidential Non-Public document entitled "Final Closing Report on PacifiCorp's 2008R-1 Renewables RFP" in PUC Docket UM 1368 on behalf of one of the Oregon Independent Evaluators (Boston Pacific). As noted in that filing letter, "Staff will file a non-confidential, redacted version of the Final Report in the near future following PacifiCorp's review of the document."

Enclosed is a redacted, non-confidential version of that report. Please note that I am serving this document on the other UM 1368 parties via email only.

Sincerely,

Mike

Michael T. Weirich
Assistant Attorney General
Regulated Utility & Business Section

MTW:nal/#1414034
Enclosures
C: All parties w/o enc.

CERTIFICATE OF SERVICE

I certify that on May 19, 2009, I served the foregoing OIE submission letter upon all parties of record in this proceeding by delivering a copy by electronic and by first class postage-paid U.S. mail to those parties accepting paper service. I am delivering a redacted non-confidential version of report to all parties by electronic mail only.

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THE OREGON INDEPENDENT EVALUATOR'S FINAL CLOSING REPORT ON PACIFICORP'S 2008R-1 RENEWABLES RFP

PRESENTED TO

THE OREGON PUBLIC UTILITY COMMISSION

by

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May 15, 2009

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I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

This is Boston Pacific Company's Final Closing Report on PacifiCorp's 2008R-1 RFP. Boston Pacific serves as the Oregon Independent Evaluator (the "IE"). We have previously filed initial and supplemental comments on the proposed RFP design and the Final RFP as issued.

The primary purpose of this report is to provide to the Oregon Public Utility Commission (the "Commission") the Oregon IE's recommendation on acknowledgement of PacifiCorp's (the "Company's") selection of a final shortlist. This report is also intended to provide the Commission with a record of the 2008R-1 RFP process since the issuance of the final RFP in October.

B. SUMMARY

Boston Pacific, as the Oregon IE, recommends that the Commission acknowledge the final shortlist as presented. Our recommendation is based upon the following six points:

(i) The selected bids represent the resources with the greatest net benefit to ratepayers as determined by the Company's Alternative Cost of Compliance (ACC) method. The ACC method used to develop the final shortlist nets the cost of a bid against the benefit of the bid, as determined by PacifiCorp's Planning and Risk (PaR) model.

(ii) The bids represent the top options from a very competitive process. The RFP received bids from [redacted]. Some of these projects offered multiple options. In total there were [redacted] bid options analyzed. This represents a total of over [redacted] offered, or about [redacted] times PacifiCorp's advertised need.

(iii) Boston Pacific's independent analysis confirmed that the selected bids represented the lowest cost alternatives for ratepayers, with an accounting for risk. Our independent analysis included the creation of our own cost annuity models for each bid option, a review of PacifiCorp's models, and a thorough review of the terms and conditions of each bid.

(iv) The shortlist provides a diversity of projects, bidders, and transaction types for negotiations going forward. In total, the list contains [redacted] projects from [redacted] different bidders and total supply of about [redacted] MW. These projects include [redacted]

(v) The RFP aligns with the Company's Integrated Resource Planning (IRP) process. The initial and final shortlist analyses used current assumptions from the IRP. In addition, the ACC analysis uses a model from the Company's IRP process to calculate the benefit of renewable resources.

(vi) While we have identified two issues - accuracy of output projections and asset life - [redacted], the Company has agreed to conduct an analysis at the time it makes its ultimate procurement decision to show how those two issues were reflected in their final decision.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

As stated, we recommend that the Commission acknowledge the final shortlist for the six reasons stated above. Additionally, we base our recommendation on our participation in the entire RFP process from design through bid receipt and analysis to selection of the final shortlist. During that time we:

(a) Reviewed multiple drafts of the RFP;

(b) Wrote multiple sets of comments on the RFP regarding such issues as the ACC method, proposed mandatory asset sale clauses, capacity values for intermittent resources, wind integration costs, and risk adjustments for Company Benchmarks;

(c) Participated in workshops regarding transmission and wind integration;

(d) Answered bidder questions and responded to bidder concerns;

(e) Confirmed the assumptions used in the analyses;

(f) Supervised the receipt of bids in person;

(g) Confirmed the initial qualification of bidders and the confirmation of proposal details;

(h) Provided input with respect to bidder disqualifications;

(h) Reviewed the price and non-price scores for the Company's Initial Shortlist process and confirmed the Company's selection of an Initial Shortlist.

Throughout this time we were in constant contact with the Company and had multiple discussions on dozens of issues. We believe the quality of the effort is reflected in the excellent response to the RFP. All of this work has led to what we believe was a fair and transparent process which complies with Commission guidelines and will, we hope, lead to a positive result with the supply of new renewable resources for the ratepayers of Oregon.

II. RFP DESIGN AND ISSUANCE

PacifiCorp filed its request to open this docket in March of 2008.[1] Boston Pacific was selected as the IE later that month. The Company filed its initial draft RFP on April 28, 2008.[2] The RFP sought to acquire up to 500 MW of system-wide renewable resources.[3] Resources had to be able to deliver to PacifiCorp's system and be on-line by December 31, 2011.

[1] Pacific Power, Application to Open Docket and Request to Issue Solicitation for Independent Evaluator, March 4, 2008, Oregon Public Utility Commission Docket UM-1368.

[2] Pacific Power, Draft Request for Proposal for New Renewable Resources, April 28, 2008, Oregon Public Utility Commission Docket UM-1368.

[3] This was later expanded to include up to five viable bids.

Boston Pacific filed comments on the draft RFP on July 3, 2008.[4] In our comments we looked to see if the RFP as proposed would yield the best possible deal for ratepayers in terms of price, risk and reliability. To do this, we sought to answer four questions: (a) Is the process fair and transparent? (b) Does the process properly measure and assign risk? (c) Will the process likely lead to a positive result? and (d) Does the process comply with regulatory rules and guidelines? We found that the RFP had many positive factors but that there were some areas of concern. These included (a) potential undervaluation of resources due to the absence of REC values and only a low "single-point" CO_2 emissions tax in the ACC calculation, (b) lack of accounting for the higher ratepayer risks of the Company's cost-of-service benchmark resources, (c) the uncertainty, at the time, surrounding the extension of the Production Tax Credit (PTC), and (d) a proposed mandatory asset-purchase clause in the pro forma PPA.

PacifiCorp filed a revised RFP on July 28 in response to these and other issues.[5] We filed supplemental comments on some of these issues on August 22.[6] On September 15, after further discussions with the IE and Staff, PacifiCorp filed a letter with the Commission detailing several changes it would make in response to the concerns of Staff, the IE and interveners.[7] On September 18, a special public meeting was held where we presented our thoughts to the Commission regarding the RFP. We recommended approval, subject to several conditions.

The Commission ultimately approved the RFP with several conditions. These conditions included, among other things, (a) removal of the mandatory asset purchase clause, (b) risk-adjustment for company benchmark bids, (c) adjustments to the valuation process to account for the capacity benefit of renewable resources, and (d) in the case of the Company selecting bids with positive (i.e. adverse) ACC values, potential additional

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[4] Boston Pacific Company, The Oregon Independent Evaluators Assessment of PacifiCorp's 2008R-1 Renewables RFP Design, July 3, 2008, Oregon Public Utility Commission Docket UM-1368.
[5] Pacific Power, Comments and Revised Draft RFP of Pacific Power, July 28, 2008, Oregon Public Utility Commission Docket UM-1368.
[6] Boston Pacific Company, Supplemental Comments of the Independent Evaluator, August 22, 2008, Oregon Public Utility Commission Docket UM-1368.
[7] Pacific Power, Letter in Response to Staff's Reply Comments and Oregon Independent Evaluators Supplemental Comments, September 16, 2008, Oregon Public Utility Commission Docket UM-1368.

assessments of Renewable Energy Credit value, Renewable Portfolio Standard requirements, and ACC values with differing CO2 emissions costs.[8]

PacifiCorp issued the RFP to the market on October 6, 2008. We filed an assessment with the Commission in November to assess how the issued RFP matched with Commission guidelines.[9] We found no major issues. For the next two months we remained available to answer bidders' questions or to pass them on to the Company. We also held follow up discussions with the Company on areas such as wind integration costs and capacity value.

Bid submission also ran according to RFP rules. Benchmark bids were to be presented prior to bid receipt, but PacifiCorp ultimately chose not to submit benchmarks in this process. Third-party bids were due on December 16, 2008. Boston Pacific was on-hand in Portland to supervise the opening of the bids. Because of a major snowstorm in the Portland area which shut down roads and the airport the receipt deadline was extended for roughly a week. Ultimately the Company made sure that all bids were received. To our knowledge there were no bids rejected because they arrived after the deadline.

Before bids could be analyzed, PacifiCorp determined that it would be required by Utah Senate Bill 202 to file an RFP in January of any year in which is expects to acquire renewable resources, regardless of whether a procurement was underway or not. Rather than file a separate RFP the Company requested and had approved a re-issuance of the 2008R-1 RFP, allowing new bidders to submit bids and current bidders to update their proposals. The call for new and revised bids was put out on January 26, 2009. The revised deadline for bid receipt was February 27, 2009. The company did receive some updates to existing proposals as well as new proposals.

[8] Oregon Public Utility Commission, Order No 08-476, September 23, 2008, Oregon Public Utility Commission Docket UM-1368.
[9] Boston Pacific Company, Comments on PacifiCorp's Final 2008R-1 RFP, November 7, 2008, Oregon Public Utility Commission Docket UM-1368.

III. BID RECEIPT AND BIDDER QUALIFICATION

Ultimately [redacted] suppliers submitted a total of [redacted] projects. Some projects contained several options, typically differences in project size, equipment, or transaction type. The total number of bid options offered was [redacted]. A list of those bid options is shown in Attachment 1.

Bids were held to several requirements: being (a) commercially operational by December 31, 2011, (b) under 300 MW in size, (c) deliverable to PacifiCorp's system, (d) a minimum output of 25,000 MWh per year, (e) unit-contingent supply, (f) qualification under RPS standards in California, Utah, Oregon and/or Washington, (g) demonstration of a right to purchase major equipment (e.g. wind turbines), and (h) a transaction in the form of a BOT, PPA or sale of an existing asset. Bidders had to provide the following information and items:

1. Pricing input sheet;
2. Appendices with estimated annual output by month and peak/off-peak period;
3. In the case of wind asset, one year of wind data;
4. Site information;
5. Permitting status;
6. Project development timelines;
7. Bidder's qualifications;
8. Bidder or credit provider's financial information;
9. Transmission plan;
10. Proposed modifications to pro forma documents;
11. A bid fee of $10,000.

Upon final receipt of bids, PacifiCorp went to work confirming bid details with bidders. Bidders provided and confirmed project information. The IE was copied or forwarded all major communications between the Company and bidders.

[redacted]

[redacted]

We were consulted on the decision to remove each of these bidders and bid options and we agree with the decision to remove them. The most difficult decision, in our mind, was the removal of the [redacted]. The size of these projects suggested that perhaps [redacted] The decision was made to remove these bids because we wanted to be fair to the [redacted]. We understand that PacifiCorp is looking at [redacted]

An additional decision point was reached when [redacted] proposed a delay in the process because they could not find an entity to [redacted] Because no other bidders requested a delay, the evaluation went on as scheduled. [redacted] did eventually submit a revised proposal, but not until mid-[redacted]. We discussed the revised proposal with PacifiCorp and the Utah IE but all agreed that it would be unfair to use this updated price without allowing other bidders to re-bid as well. Given the significant response already received from bidders and the amount of time already put in to analyzing the bids we did not want to further delay the analysis for the sake of [redacted]. [redacted] bid was therefore evaluated under the terms of its original proposal.

IV. INITIAL SHORTLIST DEVELOPMENT

After the bids were received and bid details were confirmed, the Company began the Initial Shortlist evaluation. The Initial Shortlist ranking is determined by a point score. Bids may receive up to a maximum of 100 points. The score is broken down into two parts, a price score analysis (worth up to 70 points) and a non-price score analysis (worth up to 30 points).

A. PRICE SCORE ANALYSIS

The price score analysis of each bid is separate and distinct from the ACC analysis used in the final shortlist ranking. To determine the price score PacifiCorp compares the costs of a bid versus the benefits of a bid using its RFP base model.

The costs of a bid are the following:

1. Energy payment (in the case of a Power Purchase Agreement)
2. Annual capital revenue requirement (in the case of a Build-Own-Transfer project)
3. Operating and maintenance costs (in the case of a Build-Own-Transfer project)
4. Wind integration costs
5. Third-Party transmission charges (if necessary)

The benefits of a bid are the following:

1. The avoided cost of wholesale market purchases (i.e. cost of electric power purchases from the market that would have been made absent the bid)
2. Renewable Energy Credits (RECs) produced by the bid
3. Production Tax Credits produced by the bid (in the case of a Build-Own-Transfer)

As an example calculation, say a bidder offered a PPA with a $70/MWh energy price. The cost of the bid in a given hour would be $70/MWh, plus $10/MWh for integration, leading to a total cost of $80/MWh. Additionally, assume that, in the same hour, the Company could have replaced this generation with a wholesale market purchase costing $60/MWh. Additionally, the bid produced a REC worth $5/MWh, leading to a total benefit of $65/MWh.

To get the point value for the price score analysis PacifiCorp divided the cost of the bid by the benefit. In our example above, they would divide the $80/MWh cost by the $65/MWh benefit. This leads to a ratio of 123%. Bids with a cost/benefit ratio of 80% or less received 70 points, bids with a cost-benefit ratio of 140% or more received no points. Any ratio in between ratio in the middle was linearly interpolated. This bid , then, received 19.8 points ([17/60]*70).

In the RFP Base model, the calculation of costs and benefits was performed for each month and peak/off-peak period in the asset lifespan and discounted back to the present day, at which point the cost/benefit ratio and price score were calculated as described in the example above. In terms of inputs, on the cost side, bidders provided the PPA energy payment price, the cost to construct a BOT project, O&M costs for a BOT project, and third-party transmission costs. PacifiCorp added the wind integration costs (which were $11.98/MWh in 2011 and escalated at 2.5% a year thereafter) and calculated the annual capital revenue requirements of BOT bids. On the benefit side, PacifiCorp calculated the avoided cost of market purchases from its Company-wide Forward Price Curve, as well as the value for RECs (using its 2007 IRP value of $5 per MWh for the first 5 years of operation of the asset, amortized over the life of the asset). For BOT bids only, PacifiCorp added the value of the Federal Production Tax Credit for all eligible output (about $34/MWh,[10] increasing at 2% per year, for the first ten years of the project). Bidders provided a schedule of annual output by month and by peak and off-peak period.

B. NON-PRICE SCORE

The non-price score was worth 30 points and consisted of five categories:

1. Conformity to RFP requirements;
2. Conformity to pro forma agreements;

[10] The $34/MWh value reflects the $21/MWh credit grossed up for taxes.

3. Development and feasibility of the proposal;
4. Site control and Permitting;
5. Operational Viability.

Each category was worth 6 points and bidders could earn either: (a) 100% of the points, (b) 75% of the points, (c) 50% of the points, (d) 25% of points or (e) no points.

The Company provided us with all of the initial shortlist models and the non-price score sheets. Some models were later revised based on our review and comment in order to correct for capacity factors, tax credits for solar bids, and for the fact that [redacted] The Company also changed the 80% and 140% bounds to 80% and 200% respectively. This was done to make sure that the non-price score did not become too much a determinant of bid ranking.

C. RANKING THE BIDS

We independently verified the scores in three ways: (a) we reviewed each model on a line-by-line basis to make sure that the details of the bids were properly input and that all bids used the same default assumptions, (b) we reviewed the terms and conditions of the bids and compiled our own non-price scores, and (c) we made a check of PacifiCorp's models by putting key costs of each bid option into our own cost model, which determined an annual $/MWh annuity cost for the bid option. This third step was not meant to produce a definitive value for the bid, only to make a check on PacifiCorp's more complicated models. After we reviewed the bids we conferred with PacifiCorp and the Utah IE to come to a consensus on shortlist candidates.

The overall ranking of all the bid options along with our price model rank is shown in Attachment 2.[11] The top performing bids were mostly [redacted]. In order to actually select the initial shortlist, bids were divided into the categories, per the RFP, of East Wind, West Wind and Non-Wind. The bids, grouped by categories, can be seen in Attachment 3.

In order to select groups of bid options for the initial shortlist, PacifiCorp and the IEs had several goals in mind in setting the cut-off point for shortlist inclusion: (a) selecting the bids with the greatest net benefit in terms of price and non-price benefits, (b) a diversity of bidders and projects, (c) a mix of PPAs and BOTs, (d) a relatively clear split between the score of the last bid picked and the next bid that was not selected, and (e) the RFP goal that each category contain up to 1,000 MW or 5 bids. Our comments on each shortlist category are as follows.

[redacted]

[redacted]

[redacted]

This group was selected because (a) they are the bids which delivered the most net benefit to ratepayers according to this analysis, (b) they represent a diverse mix of transaction types, bidders, and projects (c) they represent an appropriate amount of

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[11] Some of these projects included several options, for example, [redacted] PacifiCorp ran a separate analysis on each option. Therefore, the rankings in Attachment Two and Three include scores for all options proposed by bidders.

supply (potentially over [redacted] MW), and (d) there is a clear and distinct gap between the last bid selected (the [redacted]) and the next highest bid (the [redacted]).

We had only two major differences between our price model rankings and the Company's combined price and non-price score. First, [redacted] was ranked high by our model and scored well on the Company's price-score (earning [redacted] points, about the same as the shortlisted bids). However, it was not chosen for the shortlist because the bid did not fare well on the non-price rankings. Specific non-price deficiencies included [redacted]

Second, [redacted] did not fare well in our cost ranking, but we were willing to accept it on the list for several reasons including [redacted]

[redacted]

[redacted]

[redacted]

The reasons for selecting this particular group were the same as our selection of the [redacted] shortlist. The bids delivered the greatest net benefit according to this analysis, provided for adequate supply (over [redacted] MW), and represented a diversity of bidders, projects and transaction types. In addition, there was a clear gap in scores between the last bid selected ([redacted]) and the next highest bid, ([redacted]).

When these results are compared to our cost models we again have general agreement on the selection, with just two differences compared to our cost model. Had we used only our model ranking to take the top [redacted] bids, we would have taken the [redacted]. We think PacifiCorp's choice was appropriate considering the improved risk-allocation of a PPA project. Also, PacifiCorp did not initially select the [redacted] for the shortlist because they gave it a much lower non-price score that we did. We discussed this with PacifiCorp, and, after review, this non-price score was revised upward and [redacted] was selected for the initial shortlist.

[redacted]

[redacted]

Although we created our own non-price scores, because we were able to verify PacifiCorp's shortlists with our simple price model, we did not undertake an intense comparison of more than a handful of PacifiCorp's non-price scores versus our own. The most prominent exceptions are noted above. Generally the non-price scores made little difference in the overall shortlist selection.

V. FINAL SHORTLIST DEVELOPMENT

A. THE ACC METHOD

To develop a final shortlist, bids on the initial shortlist were screened using the ACC method. The ACC method, while sharing similar inputs, is a separate and distinct analysis from the initial shortlist price score analysis discussed earlier. The ACC analysis is also performed within the Company's RFP base model model, and seeks to calculate the costs and benefits of a bid. For the ACC analysis the costs are:

1. Energy payment (in the case of a Power Purchase Agreement);
2. Capital revenue requirement (in the case of a Build-Own-Transfer project);
3. Operating and maintenance costs (in the case of a Build-Own-Transfer project);
4. Wind integration costs;
5. Third-Party transmission charges (if necessary).

Benefits are

1. The avoided cost of electric power purchases from the market or generation that would have been run absent renewable resources;
2. Production Tax Credits produced by the bid (in the case of a Build-Own-Transfer);
3. The ACC value.

The lists above are similar to the initial shortlist's price score analysis, but contain two major differences, both on the benefit side. First, instead of calculating the cost of wholesale market purchases that would have been made absent the bid, the ACC method looks at the cost of replacing renewable supply using both generation and market purchases under a variety of scenarios.

PacifiCorp does this by using its Planning and Risk (PaR) model. The model is an hourly dispatch model used in the IRP process which dispatches the Company's system based on changes in load, wholesale market prices, gas prices, thermal outages and hydro generation levels. To calculate the cost of replacing renewable supply, the PaR model is run twice, once with the preferred portfolio proxy renewable resources from the Company's IRP and once without. The model estimates the cost to replace these resources via least-cost dispatch, purchasing from the market, and running available generation as it sees fit. These additional costs are divided by the MWh replaced to determine a dollar per MWh cost of replacing renewable resources.

As an example, let us say that, in one hour, the PaR model is run using the IRP preferred portfolio and produces 200 MWh of generation from proxy renewable resources. These resources are removed, and PaR is re-run. In the second PaR run this 200 MWh is replaced by a combination of 100 MWh of generation from gas-fired plants, which cost $70 per MWh, and 100 MWh of market purchases, costing $80 per MWh. Thus, the avoided cost benefit for renewable resources in this hour is $75 per MWh. This calculation is "rolled up", or grouped by year, month and peak or off-peak period.

The second major difference is that the ACC value is substituted for the REC value. The ACC value is the value that, on a per-MWh basis, makes the net benefits equal *zero*. For example, if the overall avoided cost benefit of the bid is $75/MWh and the cost of the bid is $80/MWh the ACC value is $5/MWh, since $75+$5=$80. The lower the ACC value, the more beneficial the bid. Note that a negative ACC value means the bid has a positive net benefit and vice versa.

B. ADDITIONAL ANALYSES

Beyond the methods described above, there were three additions to or modifications of cost and benefit categories for this ACC analysis; they are (a) integration costs, (b) terminal value, and (c) capacity value. These modifications came out of the RFP design process and changes in the Company's IRP process. The changes include (a) a more granular calculation of integration costs that considers both asset size and location, (b) an additional terminal value adder for BOTs and PPAs with a purchase option, to reflect the value of the Company owning the site after the life of the asset and (c) [redacted] In each case, the Company produced a description of the methodology behind these additions. For the record, we have included these descriptions as Attachment 4.

These additions ended up having no effect on the selection of bidders to the final shortlist. We reviewed and approved the methods for each of these additions. However, to be very clear, our acceptance of these methods does not mean that we agree with them 100%. Instead, our current acceptance merely means that we felt these methods were acceptable enough to use in an initial calculation. In light of the fact that they had no effect on the final shortlist selection, we did not feel the need to scrutinize them further. Had they come into play we would have gone into a more extended debate with PacifiCorp regarding some of the assumptions. We should also make it clear that PacifiCorp also views these methods as works in progress, and will be looking to further refine them in their IRP process and in future RFPs.

C. RESULTS

The results of the ACC analysis are shown in Table One. The shaded bids are the bids selected to the final shortlist.

TABLE ONE

RANKING OF BIDS FOR FINAL SHORTLIST

THIS TABLE IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

This Table shows the complete ranking of all bids which were selected to the initial shortlist. As in the initial shortlist evaluation, some bids contain multiple options (e.g. difference in turbine types or project size) so each option is the subject of a separate analysis.[12] The bids are ranked by the "ACC Value" column, which shows their ACC value prior to adjustments for capacity contribution and terminal value. Recall that the ACC value is the $/MWh benefit required to make the bid benefits equals the bid costs. The lower the ACC value, the more net benefit the bid produces.

[redacted][13]

The far right-hand column shows our cost model ranking of the bids. The ranking changed slightly from the initial shortlist ranking due to changes in [redacted] bids as a result of disclosures during the due diligence process. [redacted] This new, revised offer raised the ACC value of the bid from [redacted], out of the range of the other shortlisted bids. Based on this new, revised ACC score, the bid was removed from the final shortlist. [redacted] While this changed the bid's ACC value the bid remained in the final shortlist. [redacted] Table One reflects the revised ACC values for these [redacted] bids along with our updated price model rankings based on the revisions.

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[12] For example, [redacted]

[13] Note that because these are beneficial adjustments, and a lower ACC indicates a more beneficial bid they actually reduce the ACC value. [redacted]

[redacted]

[redacted]

We concur with the selection of this shortlist for six reasons. First and foremost, these bids represent the resources with the greatest net benefit to ratepayers as determined by the ACC method. Looking at Table One, we see a clear split between the last bid chosen, [redacted] This gap between the selected group and the rest of the projects remains, even when we adjust the ACC to account for terminal value and capacity contributions.

Second, these bids represent the best offers from a very competitive procurement process. The RFP received bids from [redacted] suppliers offering a total of [redacted] projects. As noted, some of these projects offered multiple options. In total there were [redacted] bid options analyzed. This represents a total of over [redacted] MW offered, or about [redacted] times PacifiCorp's advertised need. The fact that there were so many bids offered gives us a good indication that we are really seeing and selecting the best bids the market can offer.

Third, Boston Pacific's independent analysis confirmed that the selected bids represented the lowest cost alternatives for ratepayers, with some accounting for risk. Our cost model essentially identified the same projects as being the least-cost options for ratepayers (the chief exception being the [redacted], which was not taken, for reasons discussed earlier). The fact that our model agrees with PacifiCorp's more complicated analysis gives us confidence that these are indeed the best choices for ratepayers. In addition, our opinion is further reinforced by (a) our auditing of the

Company's Initial shortlist price score models and the ACC models, and (b) our review and evaluation of all the terms and conditions of each bid.

Fourth, the shortlist provides a diversity of projects, bidders, and transaction types for negotiations going forward. In total the list contains four projects from four different bidders and total supply of about [redacted] MW. These projects include [redacted]

Fifth, the RFP aligns with the Company's Integrated Resource Planning (IRP) process. The alignment comes in two forms. First, the initial shortlist price score analysis and the ACC analysis used current assumptions from the IRP process in modeling the costs and benefits of the bids. Second, the ACC analysis used the Company's PaR model to value the benefits of renewable resources using the current IRP preferred portfolio of renewable resources.

Sixth, while we have identified two issues - accuracy of output projections and asset life - which could still bias the ultimate choice of resources toward a [redacted], the Company has agreed to conduct an analysis at the time it makes its ultimate procurement decision to show how those risks were reflected in their final decision. These issues are discussed further in the following section.

VI. ADDITIONAL CONCERNS GOING FORWARD

A. ADDITIONAL CONCERNS

With this selection made, PacifiCorp requested best and final offer prices from each selected project and began performing additional due diligence on the bids in order to select the final winner or winners. This additional due diligence will include reviews of the wind data, permitting status, the equipment (i.e. turbine type) proposed, and integration costs.

Although we concur with the selection of the final shortlist, and recommend that the Commission acknowledge it, we want to make it clear that there is still much work that needs to be done. Specifically, as already noted, PacifiCorp must still analyze two issues which we believe could bias its ultimate selection towards [redacted].

The first issue is that of wind project underperformance. Studies by several of the leading wind power firms comparing predicted wind production to actual production have shown that current methods of estimating production typically overstate potential generation by between 5 and 10 percent. The reasons for this underperformance include (a) lower than expected availabilities due to poorer than expected turbine performance, and limited maintenance capabilities, (b) variations in year-to-year wind performances, (c) errors in estimating aspects such as wake effects, and (d) the use of an average-probability performance standard. We have attached three articles relating to this issue as Attachment 5.

For PPAs this underperformance risk is assigned to the bidder, because they are only paid for their output. However, for BOTs this risk is assigned to the ratepayers, since they will pay the same capital and O&M costs regardless of output. From an analytical standpoint, if the actual capacity factor for a BOT is lower than assumed for a bid evaluation this increases the actual dollar per MWh cost to the ratepayers, since the capacity price is spread over fewer megawatt-hours.

The second issue is that of asset life. There is some debate as to the asset lives of new wind projects because the wind power industry is relatively new compared to, say, the natural gas powered combined cycle plant industry. PacifiCorp assumes an asset life of 25 years for wind turbines; this matches its IRP assumptions, ratemaking treatment, and the assumptions used by some other utilities. However, it is not certain that this new technology can achieve that asset lifespan. There are other sources that suggest this may be optimistic.

Specifically, a review of the PPAs offered in this proceeding shows that only [redacted] offered a contract term greater than [redacted] years, suggesting that [redacted] years is what the market believes to be the asset life of these turbines. Reports from the Department of Energy[14] and the Global Wind Energy Council[15] suggest that [redacted] years may actually be closer to the asset life of wind turbines.

This issue raises another potential case of [redacted] bias. For [redacted] the risks of an asset not functioning for its promised contract duration, or alternatively, higher than expected maintenance expenditures required to keep an asset functioning, are assigned to the bidder. For [redacted] these risks are assigned to the ratepayers.

B. SENSITIVITY ANALYSES

To show what these biases may mean for the ultimate bid selection, we modified PacifiCorp's ACC models to account for an across-the-board reduction in output and an increase in annual turbine O&M and capital expenditures. The increases in annual turbine O&M and capital expenditures were made to reflect the additional costs of extending the asset life of a wind plant. Specifically, we tested (a) capacity factor reductions of 5% and 10% and (b) O&M increases of 10% and 20%.

Selected sensitivity results are shown in Table Two, below. Full results are shown in Attachment 6.

[14] U.S. Department of Energy, 20% Wind Energy by 2030, July 2008, p 16.
[15] Global Wind Energy Council, Global Wind Energy Outlook, October 2008, p6.

TABLE TWO

SELECTED OUTCOMES OF SENSITIVITY ANALYSES

ACC Value ($/MWh)

(After Adjustments for Terminal Value and Capacity Contribution)

THIS TABLE IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

The O&M cost increase does not change the bid rankings by a dramatic amount, adding a dollar or [redacted] to the ACC value. The effect of a [redacted] reduction in capacity factor, however, is fairly [redacted]. A [redacted] cut in output, e.g. changing the overall capacity factor from say [redacted] to [redacted], leads to a [redacted] or more increase in the [redacted] value for [redacted]. A 10% output cut, about the average underestimation according to one study, increases the ACC value by over [redacted] for [redacted]. Note that the [redacted] values do change [redacted] value a bit.

We are not alone in this concern. PacifiCorp is aware of these issues and has pledged to bring in a third-party consultant to examine the wind data provided by each bid. We think this is a constructive step, but question how much any expert will be able to ascertain from the wind data. The entire point of the studies mentioned and provided is that the best firms in the world have consistently overestimated output. In our mind, sensitivity analyses such as these are needed to test the risks allocated to ratepayers that are inherent in each [redacted] bid. In its IRP process PacifiCorp does a good job of testing many factors that cannot be accurately predicted and can increase risks to ratepayers. These include: gas prices, load changes, wholesale power prices, and potential carbon emissions taxes. We see these issues as no different, they are variables which could increase risk to ratepayers and their variance should be analyzed.

What is most important, from our perspective, and for our recommendation to acknowledge these shortlist results, is that PacifiCorp has committed at the time it makes its ultimate procurement decision, to conduct an analysis that quantifies the risks related to capacity factor and asset life and shows how those risks were reflected in their final decision. PacifiCorp will present this analysis when it comes to the Commission for rate recovery. We would encourage the Commission to thoroughly examine this analysis to make sure that PacifiCorp has accurately reflected the risks inherent in their choice of resource.

C. ADDITIONAL REQUIREMENTS

Finally, we note that all of the selected bids have positive ACC values. This means that those bids have positive net costs, as calculated by the ACC method. In the RFP design phase we were concerned about this outcome, since the ACC method fails to consider some factors which could add value to any renewable resource.[16]

Due to this concern, the Commission put in a requirement that, should bids in the shortlist have positive ACC values, additional analysis be conducted using differing levels of CO_2 emissions costs and considering potential REC values and Renewable Portfolio Standards Requirements. The point of these analyses was to show the true value of the bids.[17]

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[16] Boston Pacific Company, The Oregon Independent Evaluators Assessment of PacifiCorp's 2008R-1 Renewables RFP Design, July 3, 2008, Oregon Public Utility Commission Docket UM-1368. p 2.
[17] See Order No. 08-476 at p 2.

We feel that, since the selected bids have such small ACC values, rather than performing all the additional analysis contemplated by Commission Order, the Company can simply demonstrate that these bids are acceptable by looking at a higher level of CO_2 emissions costs. In other words, the Company can re-run its PaR model, which currently assumes an \$8/ton initial price for CO_2 emissions taxes, using an incrementally higher number from its recent IRP process. This increase in emissions costs will increase the cost of replacement energy for renewable resources, and thus increase the benefits of renewable generation.

The Company has committed that, at the time it makes its ultimate procurement decision, it will re-run the PaR model with a higher CO_2 cost and use those values to recalculate ACCs for the final shortlist bids. This analysis may be submitted to the Commission either in this proceeding or as part of the rate case filing mentioned above. Because of the time that it would take to perform this analysis, we are amenable to the Company performing it on a separate track rather than waiting for the analysis to recommend acknowledging the final shortlist.

ATTACHMENT 1 – List of All Bid Options Received

THIS ATTACHMENT IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

ATTACHMENT 2 – PacifiCorp's Initial Shortlist Bid Ranking

THIS ATTACHMENT IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

ATTACHMENT 3 – PacifiCorp's Initial Shortlist Ranking by Category

THIS ATTACHMENT IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

ATTACHMENT 4 – Descriptions of Additional Valuation Analyses as Provided by PacifiCorp

THIS ATTACHMENT IS NON-PUBLIC AND IS PROVIDED UNDER SEPARATE COVER

ATTACHMENT 5 – Wind Asset Underperformance Information

VALIDATION OF GH NORTH AMERICAN ENERGY PREDICTIONS BY COMPARISON TO ACTUAL PRODUCTION

Clint Johnson, Andrew Tindal[1], Marc LeBlanc[2], AnneMarie Graves, Keir Harman[1]
Garrad Hassan America, Inc.

1 INTRODUCTION

Garrad Hassan (GH) has been predicting the energy production of wind farms for fifteen years. Predictions have now been produced for over 80,000 MW of plant internationally, and many of these projects have gone forward to construction and have now operated for considerable periods. This paper focuses on the validation of energy production assessments performed by GH for wind projects in North America.

In order to assess the accuracy of these predictions, GH maintains an internal database which allows the actual production of wind farms to be compared with pre-construction projections. Using the information within this database, GH has conducted a high level investigation of how these constructed wind farms have performed in relation to the original GH pre-construction predictions. This investigation has been designed to compliment a range of more detailed validations that GH conducts on individual aspects of its methodologies and models.

GH has previously published energy validation results for North America [1]. This paper presents the latest validation results, and it is GH's intention to continue to maintain the energy validation database and to publish updated validation results.

To overcome issues associated with different periods of data being available from the various wind farms, each year of actual production data has been considered separately, and compared against the GH net energy output central estimate (P50) and 1 year 90 % probability of exceedence level (P90).

It is the aim of this work to be able to evaluate as large a volume of validation data as possible. For some wind farms only "high level" data are available, such as monthly sub-station meter readings with no detailed information on wind farm availability or performance. Wind farms with only high level data have been included within the analysis. However, where wind farms are known to have been affected by gross issues such as very poor turbine or grid availability, or such issues are apparent from comparison with data from nearby wind farms, such wind farms have been excluded from the assessment. Such exclusions of wind farms from the database is inevitably somewhat subjective, however, the results are also presented in this paper for the subset of data for which the availability is known.

The results of a previous comparison of actual to projected energy production for North American wind farms identified that, on average, across the data available at that time there was a tendency for energy production to be over-predicted. Following publication of that paper GH have undertaken a critical appraisal of all aspects of energy analysis methodology and assumptions to attempt to identify potential sources of bias in an analysis. As a result of this process some factors have been identified where amendments to analysis methodologies and assumptions have been made. Some amendments are generic and applicable to all GH analyses, while some reflect current North American market conditions. These areas are described within this paper.

[1] Garrad Hassan and Partners Ltd.
[2] Garrad Hassan Canada Inc.

2 ENERGY VALIDATION RESULTS FOR NORTH AMERICA

Results for the whole of North America have been considered. The database includes results from 41 wind farms with operational periods which vary from 1 year to 8 years. There are currently a total of 113 wind farm years in the validation database.

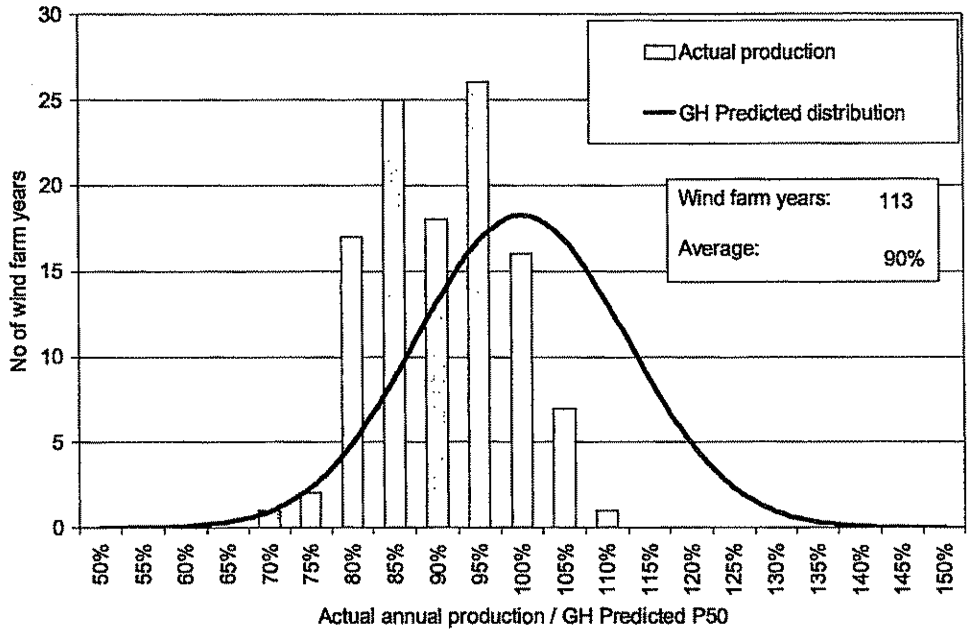


Figure 1 Distribution of annual production relative to GH projected central estimates

The distribution of annual energy production, relative to the GH central estimate, for the 113 wind farm years in the database is presented in Figure 1. It can be seen that on average wind farms have produced 90 % of pre-construction estimates.

The potential causes of the above discrepancy from the "ideal" 100 % result are briefly summarised below.

Windiness of operating period.

It is noted that there are a substantial number of wind farms for which data are available from Texas and, for example, Texas generally experienced a low wind year in 2007. Windiness of the period therefore may explain some of the difference. This is considered further below.

Wind resource prediction error

It may be that bias has been introduced in the different elements of the wind speed assessment process including; wind speed measurement bias, long term wind speed adjustment, extrapolation to hub height, and wind flow modeling.

Energy loss factor prediction error

It may be that bias has been introduced by differences in estimated and actual energy loss factors including; wake loss modeling, availability, electrical losses, turbine performance, environmental losses and losses through curtailment.

As discussed above for a subset of the full data set availability data are available, and these data have been used to adjust the actual production of the wind farms to be consistent with pre-construction estimates of availability. The purpose of this exercise is to assess to what extent such differences may explain the discrepancy. The distribution of actual energy production compared with GH pre-construction energy estimates is presented in Figure 2 for the subset of 70 wind farm years for which availability data were available.

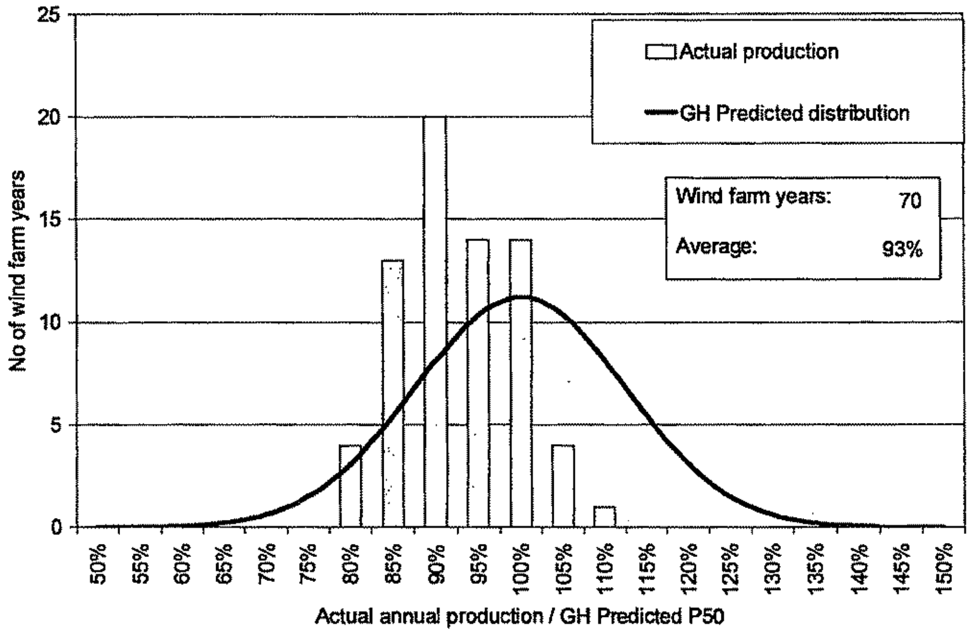


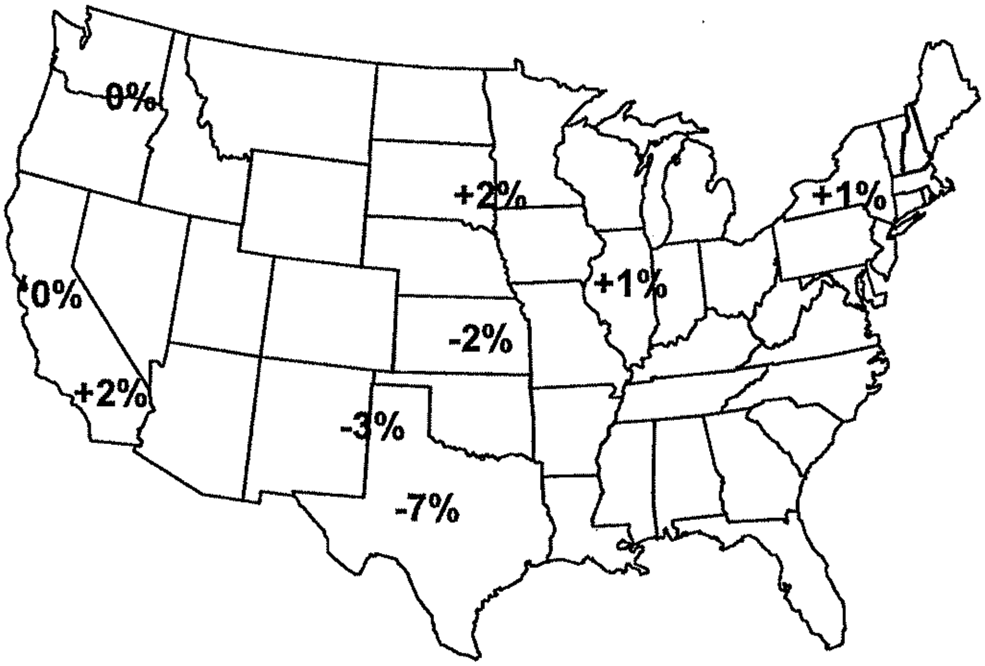
Figure 2 **Distribution of annual production relative to GH projected central estimates including availability adjustment for a subset of 70 wind farm years**

It is noted that when such an adjustment is made the average production increases to 93 % of the pre-construction value. Differences in actual availability from pre-construction availability estimates therefore explain some of the observed discrepancy. Additionally it can be seen that the availability correction has made a material difference to the tails of the distribution, although it is also noted that the data set is relatively small to read too much into this part of the distribution. The issue of current availability trends in North America is discussed further below.

In a previous paper [1] there was significant discussion of legacy issues, such as the prevalence of poor mounting arrangements of sensors – the so called "stub mount" effect causing a significant but difficult to quantify bias in the predictions of wind farm energy production.

In order to allow a focus on the most up to date measurement norms and analysis techniques GH have focused on the production of projects in 2007. A key question raised above was what impact has windiness had on the results observed. In order to address this question GH have attempted to define a windiness index for each of the key wind energy regions in North America. Such windiness indices have generally been based on available sources of ground based wind speed measurements. While careful checks have been made to ensure the consistency of the data and the relevance of the wind data to wind farms in the region in question, it is stressed that the results of these indices are only indicative in nature and intended to be used only in this "high level" assessment to attempt to understand the observed discrepancies between actual and projected energy production.

The indicative windiness indices for different regions are presented on a map of North America in Figure 3 below.



Note: indices are windiness – energy variations will be larger

Figure 3 Indicative windiness indices for key US wind power regions in 2007

The 2007 energy production data have been adjusted for windiness using the above indicative indices and, for the subset of data for which availability is available, adjustments have also been applied to adjust production levels to pre-construction availability assumptions. The results of this process are presented in Table 1 below.

	All data (41 wind farm years)	Windiness adjusted (41 wind farm years)	Windiness and availability adjusted (27 wind farm years)
Average ratio Actual/predicted	90%	92%	96%

Table 1 **Comparison of average to predicted energy production for 2007 data and the effect of correcting production for windiness and to pre-construction availability levels**

It can be seen from the above that when the data from the most recent year are considered and when adjustments are made for the influence of windiness and of availability then the average ratio of actual to the predicted energy reduces to within 5 % of the ideal 100 % result.

Although the number of wind farms in the GH database in any given year for years prior to 2007 is somewhat limited, GH has also undertaken a similar process to adjust for observed windiness and availability for all production years prior to 2007. The outcome of this exercise show similar results overall, with the average ratio of actual output to predicted output of approximately 94 % to 96 %.

3 CRITICAL APPRAISAL OF METHODS

GH has undertaken a rigorous evaluation of what elements of energy analysis may lead to a bias in the result. This has involved a very detailed assessment of the 10 minute SCADA data from a range of North American and other wind farms. This process has identified areas where there is potential for bias to be introduced, and where appropriate, amendments have been made to assumptions and methodologies.

The key issues from this process are presented below:

Availability

A previous GH publication [2] has identified the material "ramp up" in availability which is currently observed for North American wind farms. Figure 4 below presents an updated graph showing how the availability levels vary for the North American wind farms over time from construction compared to the equivalent characteristic for wind farms from Europe.

The larger data set which is now available indicates that on average, even by year 4, availability levels of only approximately 96 % are being achieved. Based on this new information GH has amended the availability ramp up characteristic which will typically be applied to North American wind farms, and the characteristic is presented on Figure 4. A detailed discussion of potential causes of the lower availability levels achieved in North America compared with Europe was given in [2]. It is considered that there are a number of reasons why the availability of wind farms will improve with time and therefore GH considers that a "ramp up" is the appropriate model for wind farm availability. Many North American wind farms experience either relatively extreme cold temperature or relatively extreme hot temperature conditions or both cold winter and hot summer conditions. It is considered that such an environment does make faults more likely and more difficult to resolve. Additionally there tends to be a relatively high incidence of meteorological events which may impact availability such as hail storms and lightning. GH have therefore reduced the availability level which the wind farm is assumed to ramp up to until such time as the availability data demonstrate this assumption is no longer appropriate for the North American market. It is stressed that when a full technical review is undertaken this characteristic will be considered on a site specific basis with a detailed consideration of the specific technology and specific O & M arrangements.

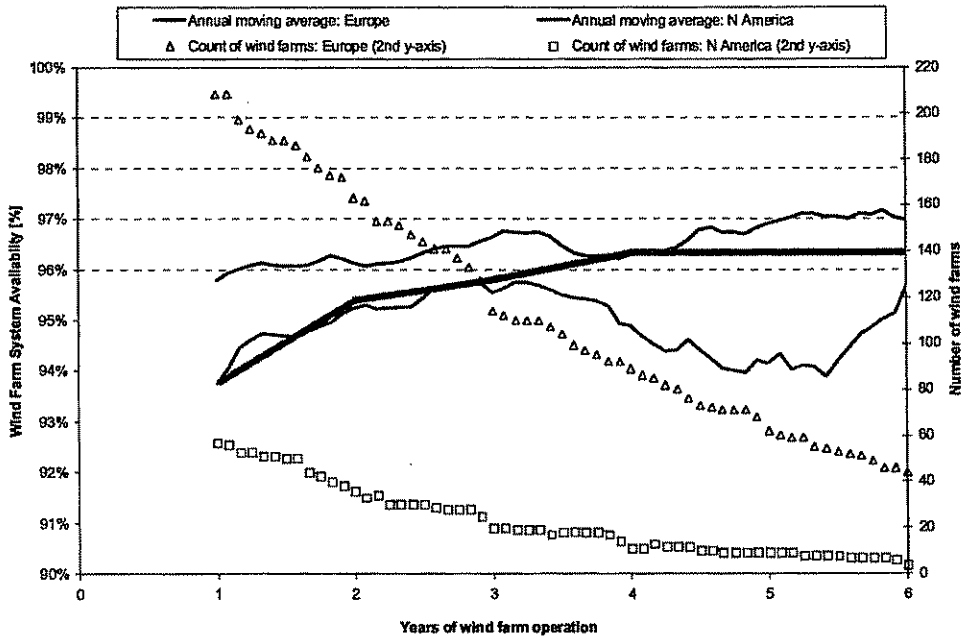


Figure 4 **Comparison of availability with time for North American and European wind farms – Thick green line generic future availability ramp up assumption**

Power curves

GH have used power curve test data and wind farm SCADA data to undertake a critical appraisal of how the turbine manufactures' sales power curve should be interpreted in the context of a pre-construction energy analysis. A comprehensive description of this work and the findings from it are provided within a separate paper presented at AWEA WINDPOWER 2008 [3].

The key aim of the paper was to consider the site specific power curve adjustments which may need to be applied to pre-construction energy production estimates due to the meteorological conditions at a specific wind farm site. The paper also considers how a turbine power curve measured in accordance with the IEC standard should be interpreted in the context of a pre-construction energy assessment. The key findings from the investigation of these issues are summarised below:

Effect of turbulence on a power curve

Analysis of relevant data sets, as described in [3], has demonstrated that for sites with particularly high turbulence levels there is potential for the energy production of the wind farm to be reduced when compared with lower turbulence sites. A model has been proposed to apply a turbulence power curve adjustment factor for sites where the predicted turbulence levels—inclusive of wake effects—are more than 15 %. As an example the model defines a reduction in energy of 1 % for a site with 18 % turbulence intensity. A comparison of power curves for 15 and 18 % turbulence intensity to illustrate the degradation of the knee of the power curve for high turbulence levels is presented in Figure 5.

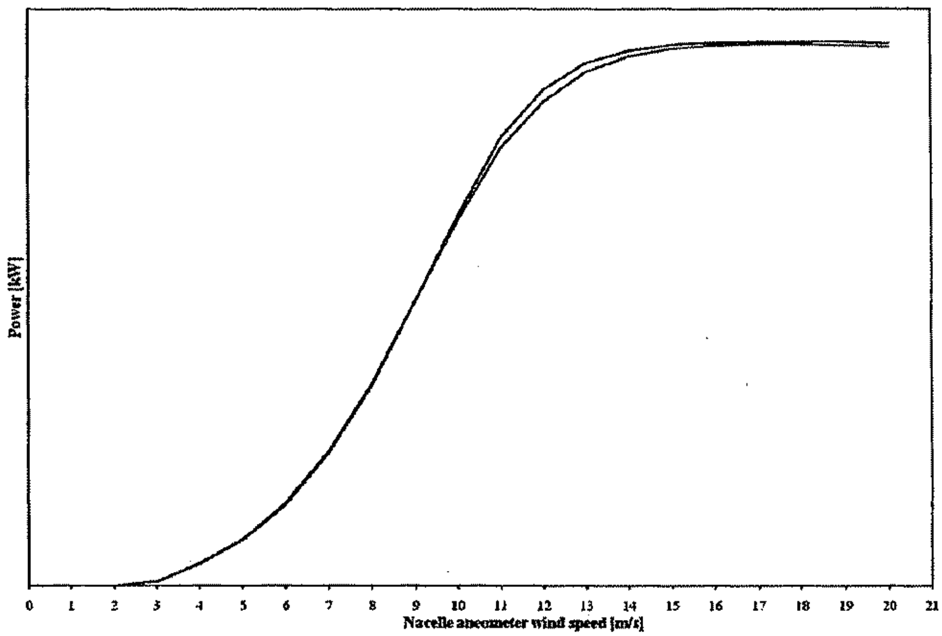


Figure 5 **Example of the degradation of the knee of the power curve for an 18 % (blue line) turbulence intensity site compared with a 15 % (red line) turbulence intensity site**

Effect of upflow on power curve

It is argued in [3] that for sites with significant upflow there is the potential for the energy production of the wind farm to be reduced when compared with flat terrain sites. A model has been developed where sites are characterised into simple terrain and complex terrain categories. For complex terrain sites an upflow power curve adjustment factor is applied. The average upflow is estimated using a model for which the inputs include a directional definition of terrain slope for each turbine, the site wind rose and an assumed dependence of upflow to terrain slope. As an example for an escarpment site with 20 degree slopes and a fairly uniform wind rose the model defines a reduction between 0 and 1 % which will increase beyond that level for steeper slopes or for slopes strongly aligned with prevailing wind directions.

Interpretation of a power curve measured to International Standard IEC 6-1400 Part 12

It is considered that the definition of wind speed provided within wind turbine power curves based on the widely adopted international standard IEC 6-1400 Part 12 effectively includes a blockage effect from the presence of the wind turbine. The issue is illustrated in the schematic diagram presented in Figure 6 below.

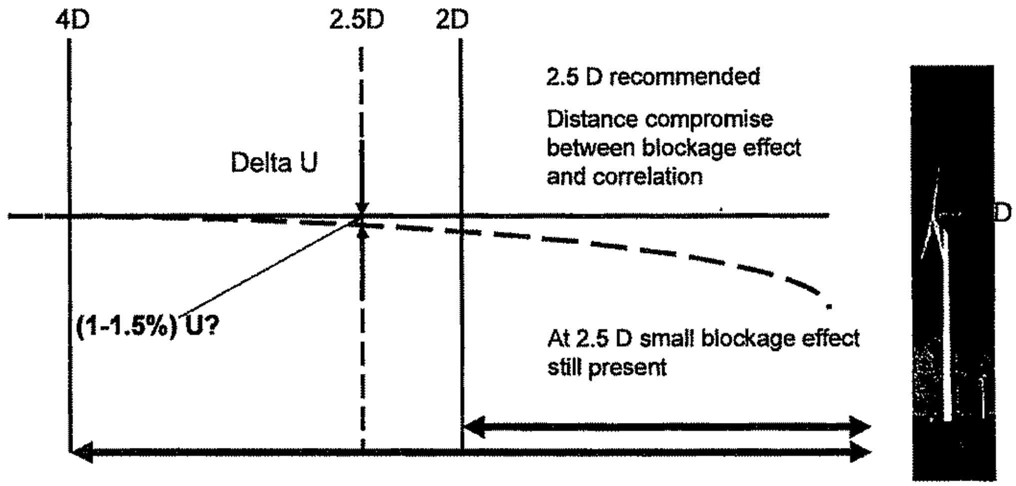


Figure 6 Blockage effect schematic

Such a blockage effect is not present for wind speed measurements made on pre-construction wind farm sites and to enable a like for like comparison between the site wind speed measurements and the definition of wind speed within the power curve an adjustment is necessary. To account for this effect, a generic power curve adjustment factor of 99 % is applied. It is stressed that this is not implying the power curve has been measured incorrectly, rather that the power curve needs to be appropriately interpreted in the context of a pre-construction energy assessment. A more comprehensive discussion of this issue is provided in [3].

Are turbines performing as they should?

In 2007 and 2008, GH has undertaken a large volume of highly detailed analyses based on 10-minute SCADA data to assess the performance of North American wind farms. From this it is concluded that for significant periods of time for significant numbers of wind turbines the data demonstrate material performance deviations from the expected sales power curve of the machines. It is considered that some of these issues are caused by teething hardware issues, but of more importance typically are software issues which cause the machines to not reach their intended power curve or operate in a non-optimal way. It is considered that it takes time and focus to ensure wind turbines continuously operate as they should. GH has concluded that these performance issues have played a role in the discrepancy between actual and expected energy production. In order to capture these effects for future assessments, GH considers that while there is a ramp up in availability it is also likely that there will be non-optimal control of the machines. GH has therefore assumed that for the same period as the assumed availability ramp up, in this case four years, an allowance will be made for power curve teething issues. A typical allowance for this factor is an effect of 1 % on annual energy production during the period of ramp up. Operational data from wind farms will continue to be reviewed and as typical trends with regard to this issue change then the assumption will change. Additionally, where detailed information about the O&M arrangements has been reviewed this assumption may be changed. An example of the effect is illustrated in Figure 7 below.

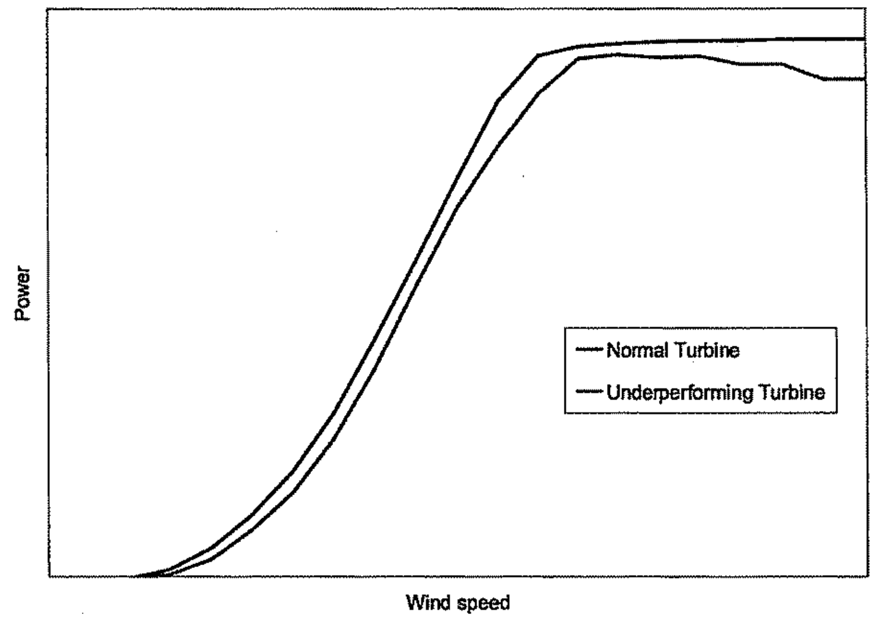


Figure 7 **Comparison of normal operation of a turbine with a period of under performance thought to be used by controller related issues**

Large wind farm wake effects

Wind turbines extract energy from the wind and downstream there is a wake from the wind turbine where wind speed is reduced. As the flow proceeds downstream there is a spreading of the wake and the wake recovers towards free stream conditions. The wake effect is the aggregated influence on the energy production of the wind farm which results from the changes in wind speed caused by the impact of the turbines on each other. GH has generally used an "eddy viscosity" based wake model within the GH WindFarmer computational model [4, 5] to predict wind farm wake effects. This model has the benefit over the simpler PARK model developed by Risø Laboratory in Denmark in that the site specific turbulence intensity, which wake recovery is sensitive to, is a direct rather than indirect input into the model.

Much of the original validation of the eddy viscosity wake model within WindFarmer was undertaken on what now would be considered to be medium sized wind farms, and as data from large wind farms has become available such data are clearly valuable to extend the validation of the model. Recently constructed large offshore wind farms provide a unique validation data source as the extreme flatness and homogeneity of the sea, when compared with even relatively flat onshore sites, allow differentiation between wake effects and terrain effects which is generally very difficult to achieve onshore.

Validation of wake loss models against actual production from large offshore projects indicates that wake loss models are under-predicting the actual wake impacts under some scenarios [6]. There is currently significant debate over the physical mechanisms which may be causing the observed results to deviate from the predictions obtained with a conventional wake model for large offshore wind farms. GH is currently involved with internal and externally funded research projects aimed at improving modeling techniques for large offshore wind farms. For onshore wind farms, due to the difficulties of differentiating wind speed changes due to wake effects from those due to terrain effects, the quality of the data sets available for validation of wake effects for large onshore are lower. However, it seems likely that the mechanisms which are causing under prediction of the wake effects for large offshore wind farms will also be experienced for large onshore wind farms at least to a certain degree. For large offshore wind farms where under-prediction is observed the following criteria are present:

- The wind farms of approximately 100 MW or more;
- The ambient turbulence is low;
- Many of the turbines have a large number of upwind turbines for significant wind directions.

Given the potential concerns that the standard wake models may start to under-predict the wake effects for onshore wind farms as wind farms become large, GH has developed a pragmatic large wind farm wake model. The large wind farm wake model makes an adjustment to the results obtained with the standard wake model. The model considers the proportion of turbines which may be considered to be in a "deep array" situation similar to that seen at the large offshore wind farms used for the validation work described above. A wake adjustment factor informed by the validation results from the large offshore wind farm is then applied. Ambient turbulence intensity and wind rose are parameters within the model.

Conventional wake models under-predict the energy production of the current largest offshore wind farms by approximately 2.5 %. The result of applying the above large wind farm wake model will reduce the predicted energy production of the wind farm by between 0 and 2.5 %, depending on the specifics of the wind farm. It is stressed that this is a pragmatic model and more sophisticated modeling techniques are in development.

4 CONCLUSIONS

GH maintains an internal energy production validation database which contains actual wind farm production data and GH pre-construction energy projections. The database contains only "high level" information which, as a minimum, includes monthly wind farm production and in some cases more detailed information such as availability.

It is only by looking at large volumes of data that a scientific view on the typical accuracy of predictions can be made. This paper has presented the current results from the energy validation database containing 113 wind farm years of data from North America. GH has focused particularly on the performance in 2007, for which the production of 41 wind farms is considered.

The "raw" results show that predictions have, on average, been over-predictions. Focusing on 2007 production data after adjustments are made to attempt to adjust for windiness in the different regions and to correct availability levels to pre-construction estimates, the predictions are within 5 % of the actual result.

GH has gone through a process to assess what elements of energy analysis may lead to a bias in the result. This has involved comprehensive and rigorous assessments of the 10-minute SCADA data from several North American and other wind farms. This process has identified areas where there is potential for bias to be introduced, and some amendments have been made to assumptions and methodologies where appropriate.

A database of wind farm availability data has been assessed to evaluate what average availability levels are being achieved for wind farms in North America. From this, is concluded that a "ramp up" in availability levels is observed, and GH have revised standard availability assumptions used for pre-construction assessments in light of the latest availability data.

For the period over which availability is ramping up it is frequently observed that wind farms have material loss of energy caused by incorrect setting of wind turbine hardware and software resulting in periods of degraded power curve performance.

GH has critically reviewed the interpretation of the sales power curve as a potential source of bias in energy assessments. From this it has been concluded that, on a site specific basis, adjustments are required to the sales power curve to account for high turbulence and steep slopes. Additionally to account for the potential for "blockage" from the turbine when power curve measurements were originally undertaken an adjustment factor will now be applied.

The validation of conventional wake models was undertaken on what would now be considered to be small to medium wind farms. Data recorded at the largest offshore wind farms—which provide excellent data sources for validation of wake models due to the absence of terrain effects—indicated that there is a tendency for wake models to under-predict the wake losses for the largest offshore wind farms. There is a concern that these influences may also extend to the largest onshore wind farms. GH is therefore now applying a large wind farm wake model adjustment and is working along with many of the leading wind energy research organisations to refine wake models in light of these data.

The net result of the above amendments to GH loss factor assumptions is to reduce the predicted Annual Energy Production by 2 to 5 % depending on the specifics of the site.

It is stressed that high quality wind measurement campaigns are of vital importance for robust wind farm energy production estimates.

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AWS Truewind

Understanding and Closing the Gap on Plant Underperformance

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AWEA Windpower

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Wind Plants Generally Underperform vs. Preconstruction Estimates

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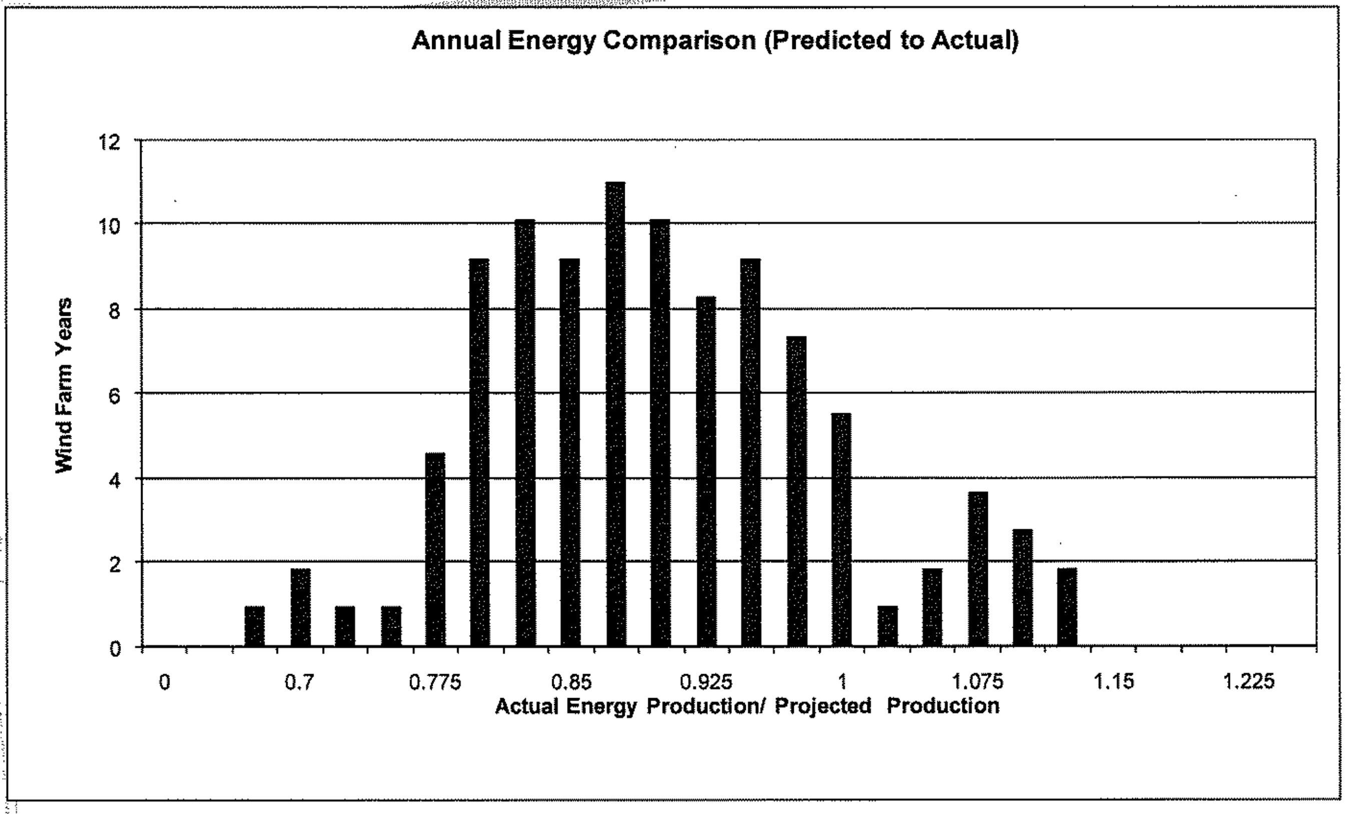
(all projection sources)



Underperformance of ~ 10 % is typical and prevalent across industry

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Understanding Plant Underperformance

- Plant underperformance is a real and significant issue for the industry

- Contributions from numerous sources
  - Can be hard to isolate, and evaluate
  - Inherent wind variability complicates the analysis

Like an onion, need to peel back each of the many layers involved to understand all that's inside

Evolution of Performance Estimation

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- AWS's pre-construction estimate methods have been evolving since the late 1990s … numerous areas of adjustments
  - Resource assessment campaign design
  - ASOS Station correction
  - Elevation adjustments
  - Modeling and model evolution
  - Methods standardization
  - Availability estimates
  - Electrical losses
  - Etc, …
- Project time lag and methods evolution leads to an issue = >
  - Most operational data reflects old projection methods
  - Limited data available for direct comparison on today's methods

Closing the Loop with Operational Data

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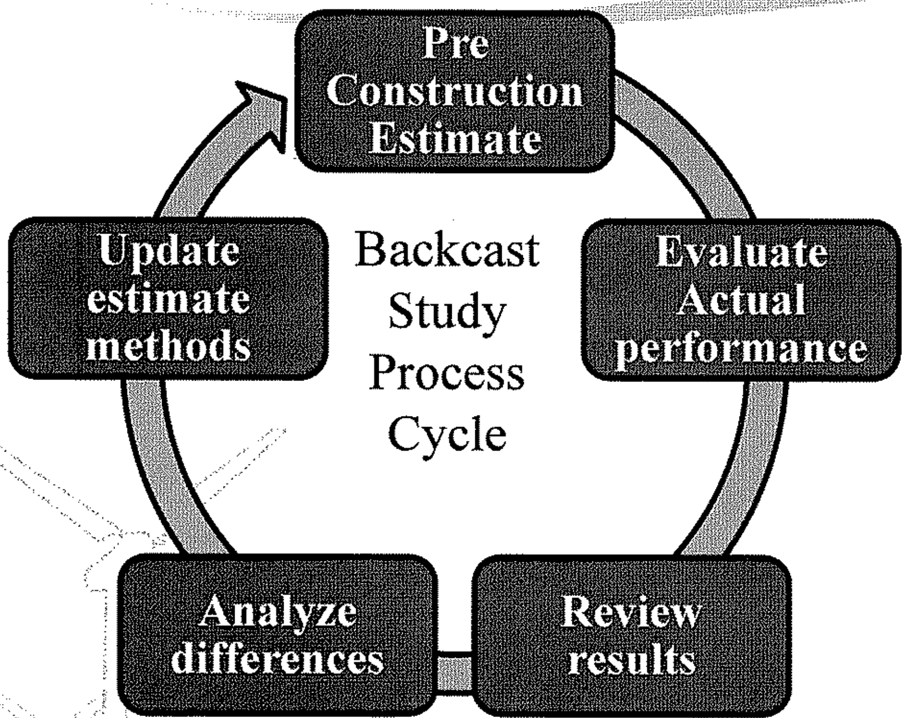

- Conduct "Backcast" studies to allow direct comparison with today's methods
- Blind projections for comparison with available plant operational data
- Use all data sources for some evaluation elements (e.g. availability analysis)
- Study in process and continuing

Backcast studies can accelerate the feedback process

Early Findings
– Some of the key contributors

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- Resource Assessment Campaign Biases
- Regional Climate and Variability
- Actual *Total Plant* Availability
- As-Built Plant Characteristics Changes from Plan
- Sub-Optimal Operations

(Factors such as array blockage, wake effects, and actual turbine performance in complex wind flow regimes are also expected to be significant)

Contributions across the project life cycle

The Outer Layers

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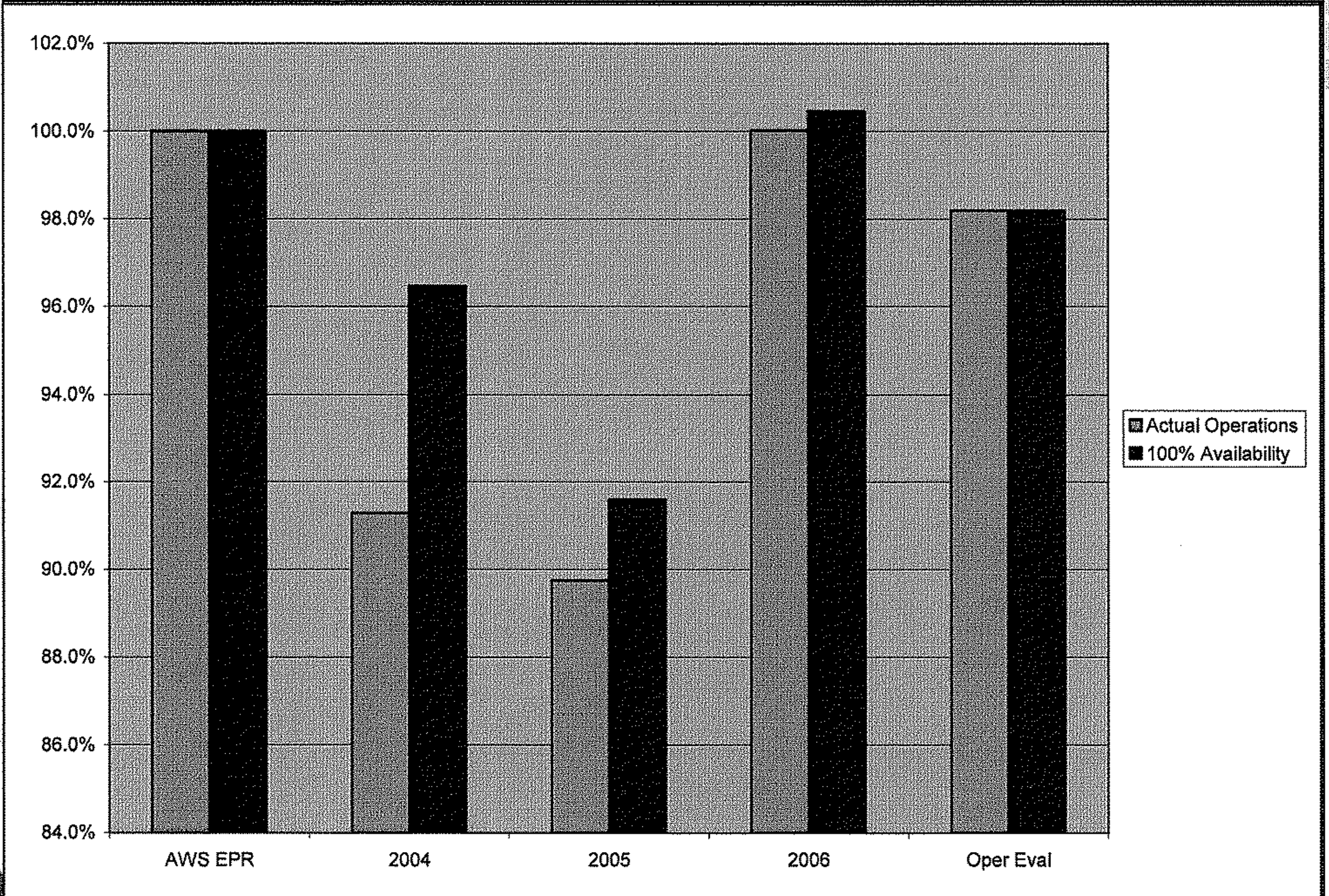
- Short term climatology
  - Regional clustering of farms
  - A non-random part of the shortfall from a "random" source
- Availability
  - Definitions matter; need *total plant* availability
  - First year start up effects can be significant on a rapidly growing fleet

Need to address these first

Case Comparison
– Operational Performance



Wind and Availability Are Major Drivers on Actual Performance

US Wind Plant Additions 2001 to 2006

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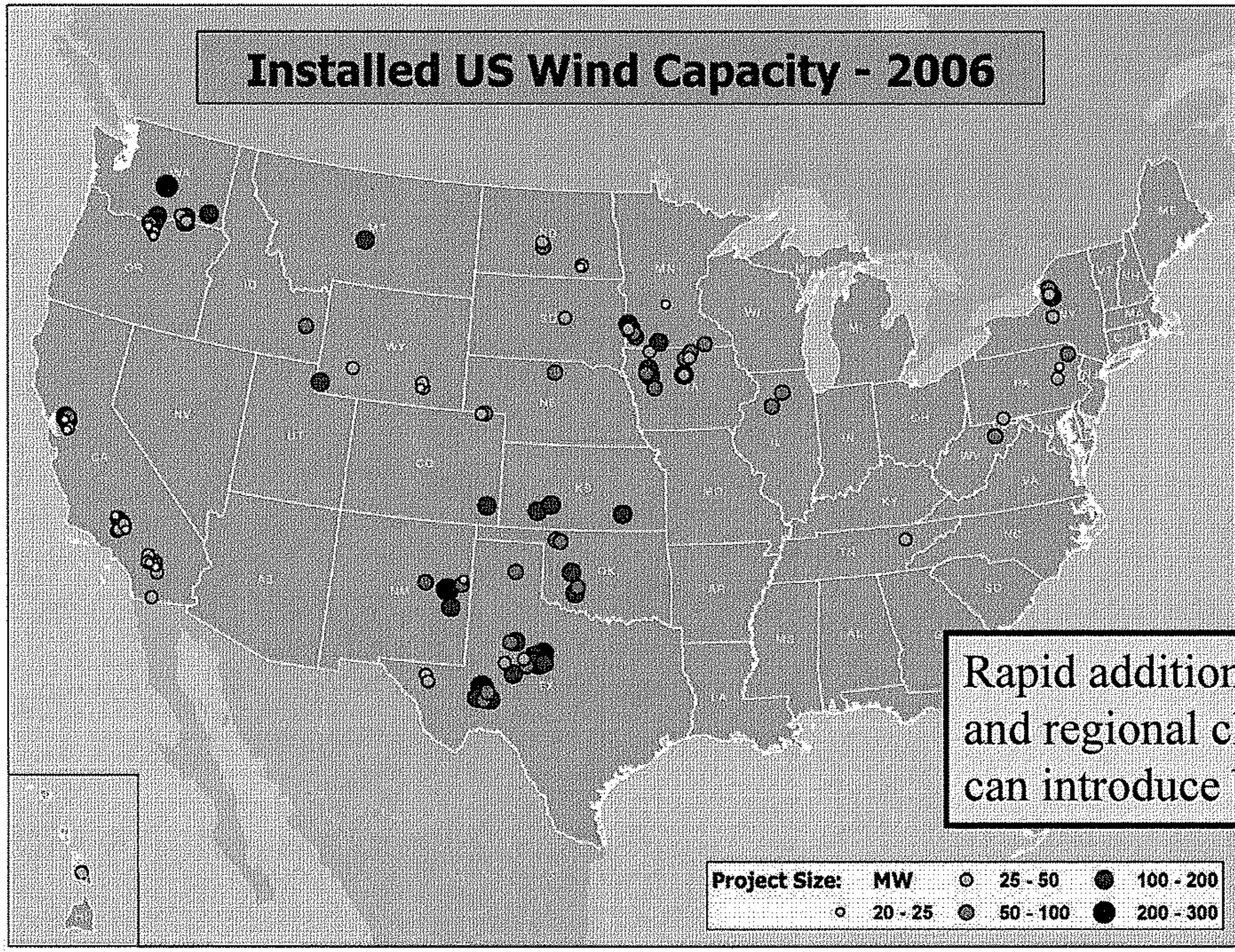
(Farms >20 MW capacity; AWEA database)



Rapid addition of farms, and regional clustering, can introduce biases

Regional Climate Affects and Clustering

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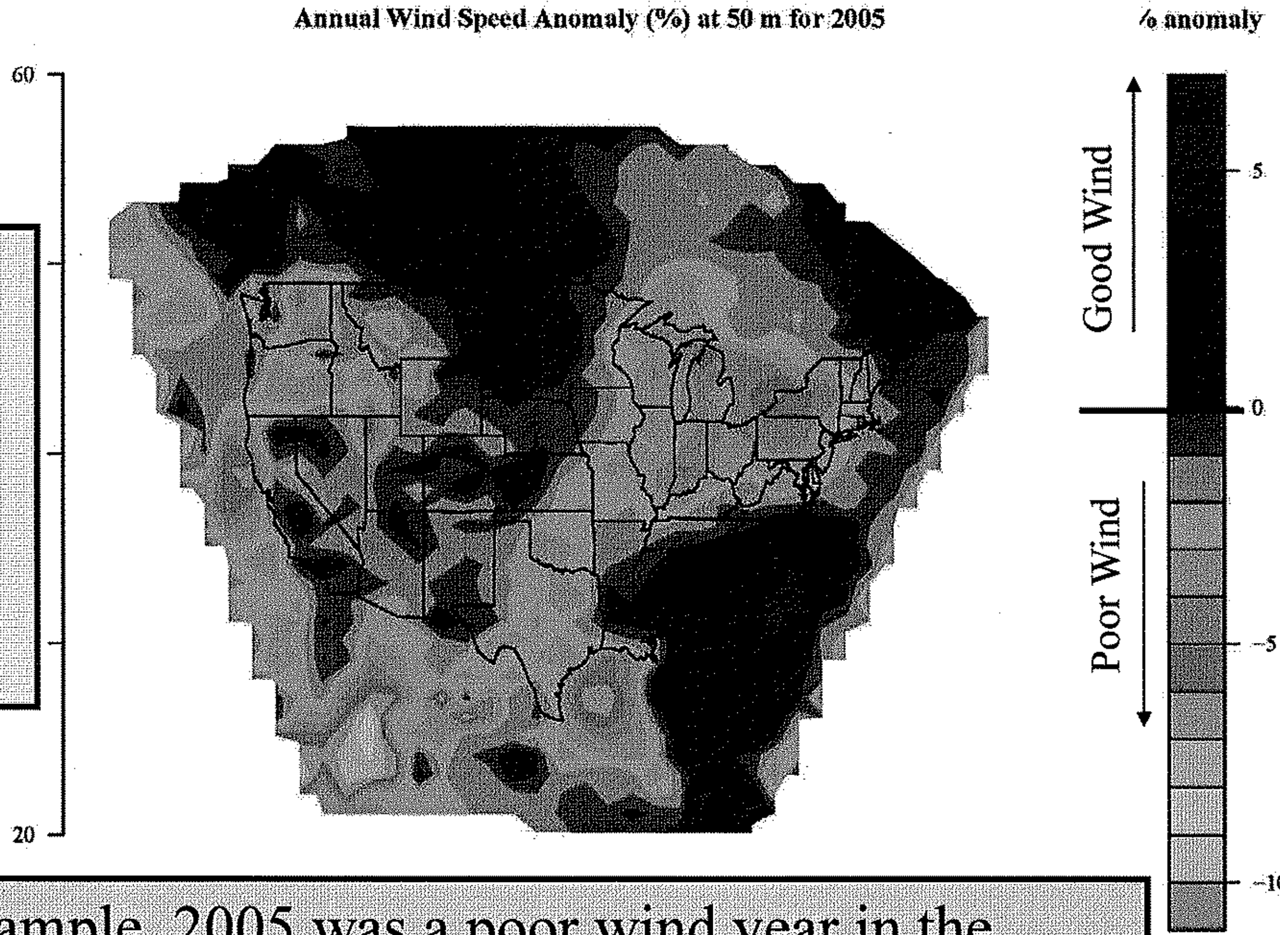

Regional wind variation can interact with plant clustering to introduce a source of bias

For example, 2005 was a poor wind year in the Northwest, Northeast and Texas – homes for many farms

Effect of regional wind variability

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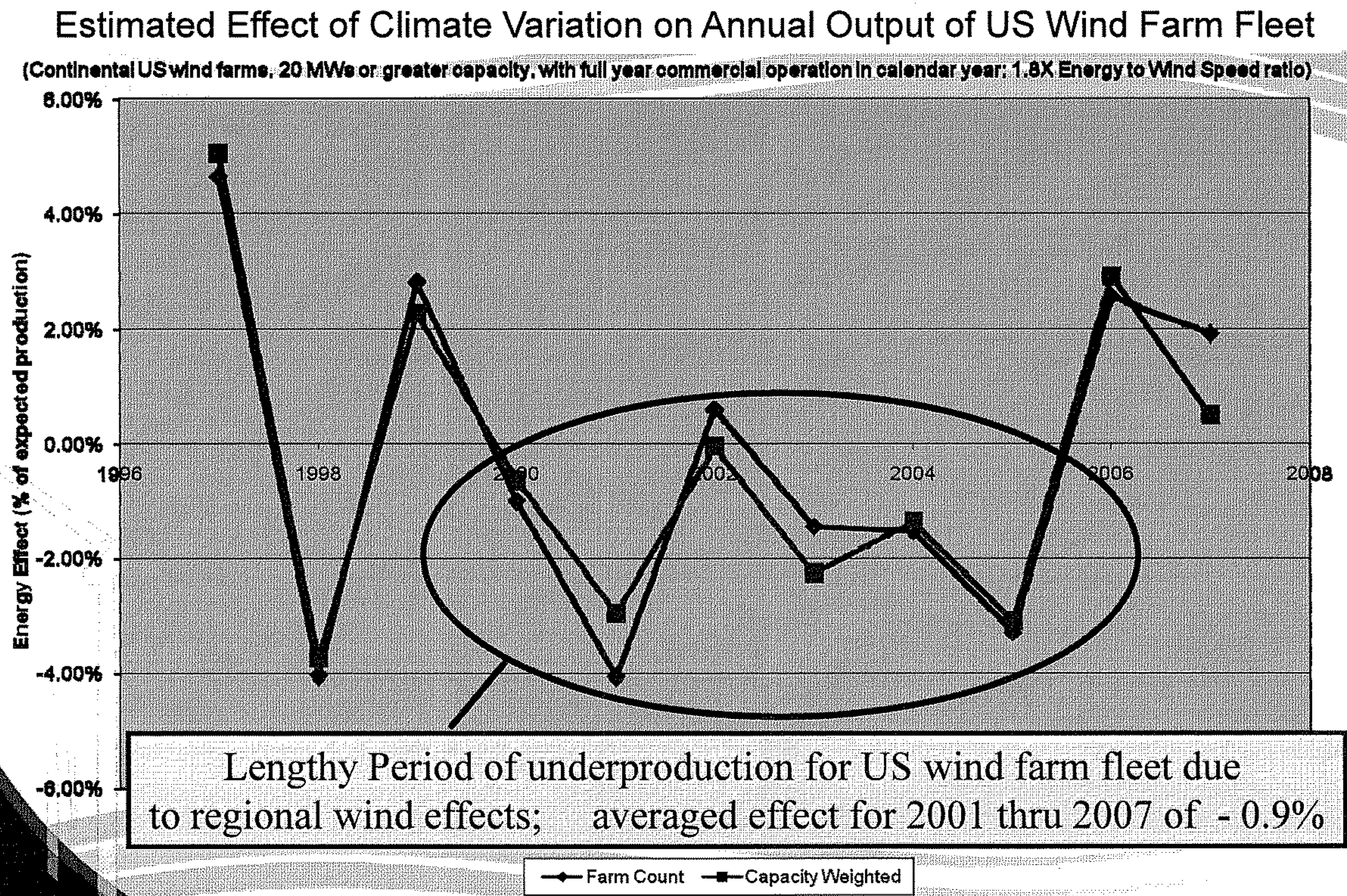

First year availability and fleet contribution

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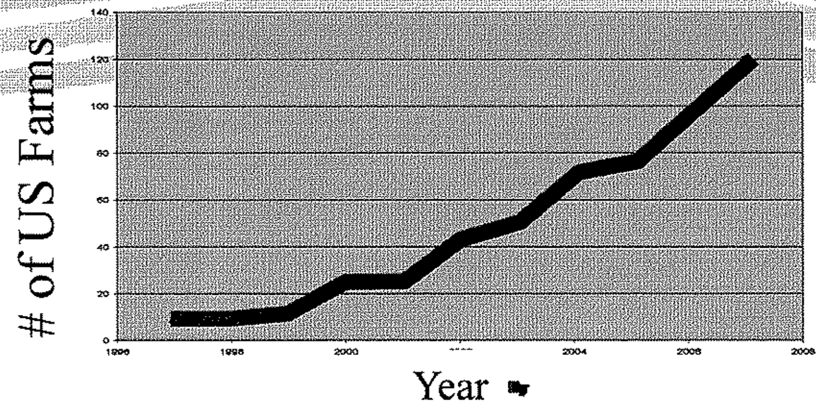
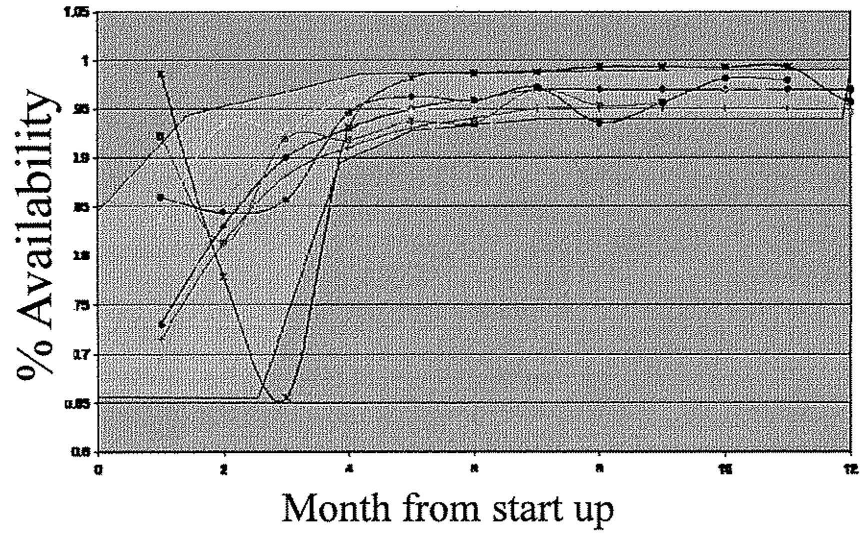
- First year availability "teething pains" may reduce output 4% or more
- It's only one plant, one year…what's the big deal?
  - Rapid Growth
    =>Lots of new plants in a typical US "fleet"
    => Lots of "first year" results in data set

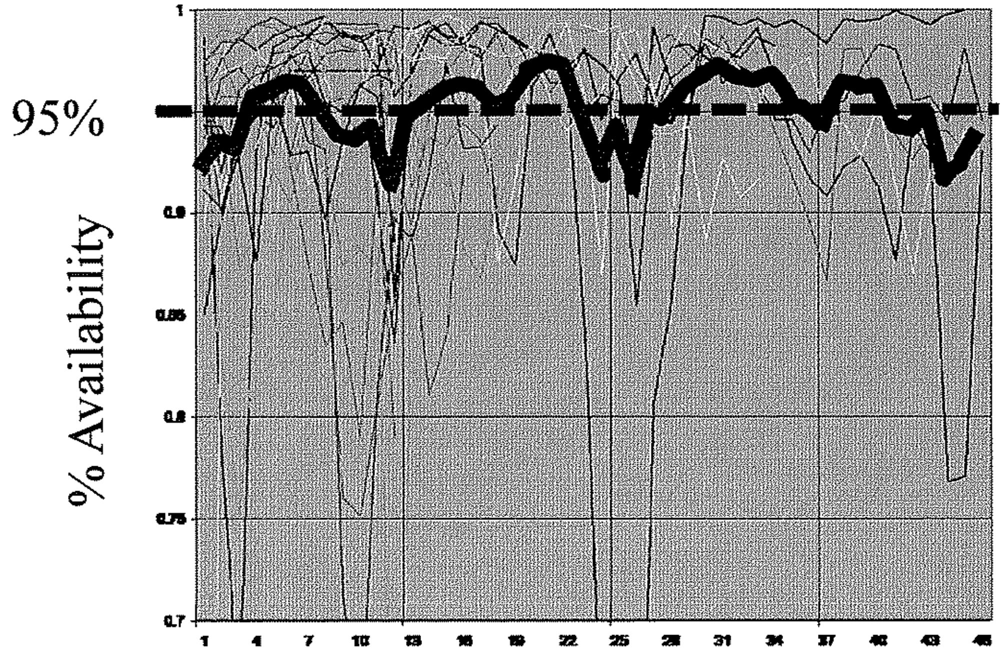




Estimated ~1% effect on fleet average output for overall US fleet

Actual Availability

- Early estimates often 97% effect on energy
- Often falls below expectations
  - Plant affects
  - Grid affects
  - Weather out time
    - Where is it counted?
  - Other issues "not in the contract"



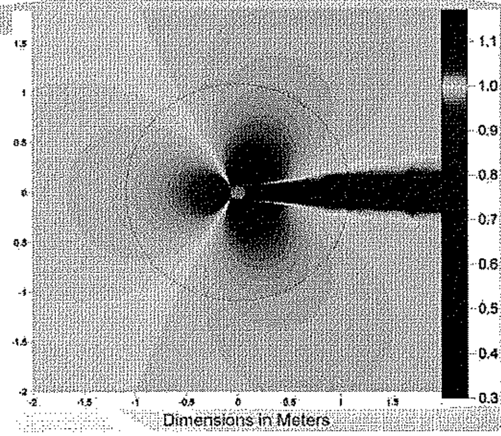
- Two key factors on availability losses:

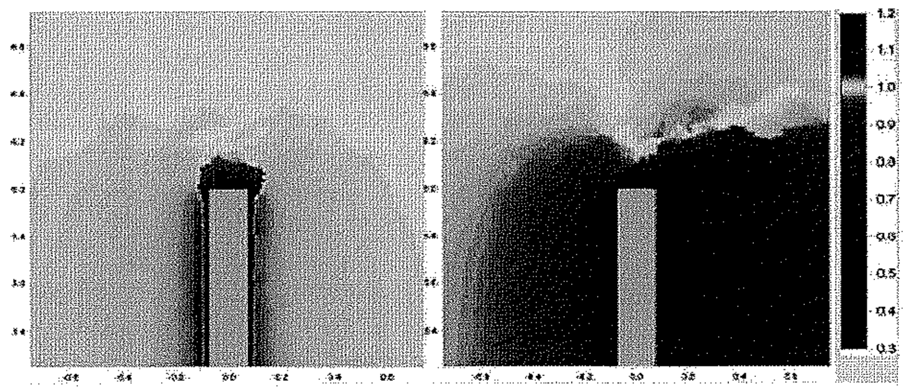
TURBINE CONTRACT ≠ ACTUAL PLANT

LOST ENERGY > LOST TIME

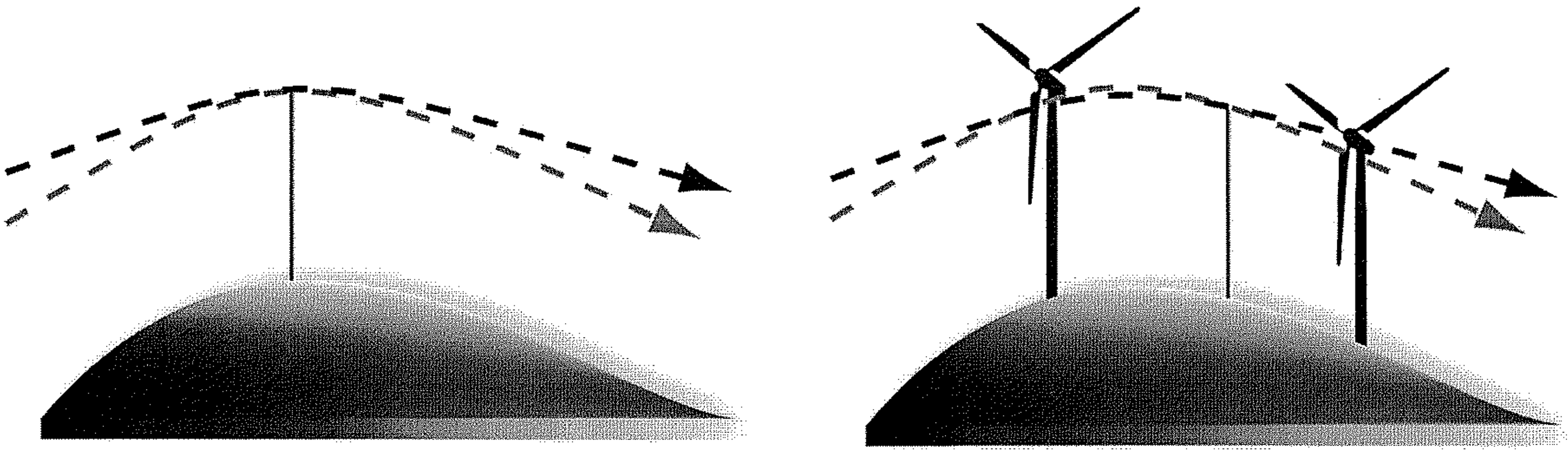
Resource Assessment Campaign Bias

- Many sources of bias from very early in the project life cycle
- Some examples
  - ASOS shifts
  - Instrument mounting effects
  - Tower siting & modeling approach





Resource assessment campaign bias – an example



- Tower siting can lead to bias from terrain effects
- Potential shift of several percent or more in wind speed…leading to a 3 to 5+ % bias in energy
- Can be addressed by proper resource campaign design

As-Built Plant Characteristics

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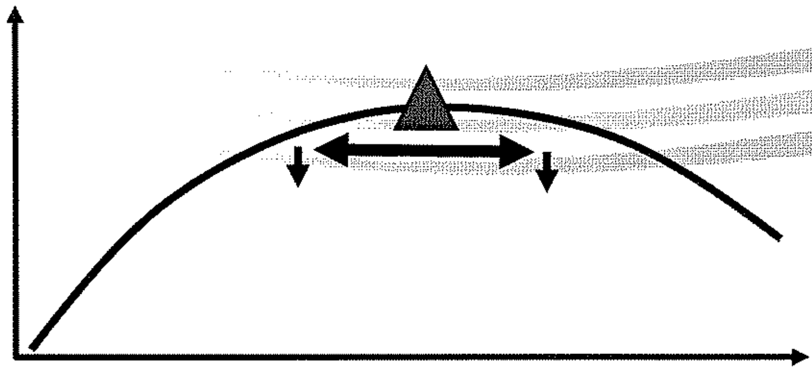

- *Any* changes from an ***"optimized"*** farm will lead to lower performance
- Most farms have some changes from preconstruction plans
- Not generally as big a factor
  - But can be evaluated and reconciled up front

Estimated Energy Effects of Changes – Examples from various cases studies

Turbine X Y placement	0.4%
Turbine Z placement	1.0%
Collection and Electrical System	0.5%
Metering & interconnect point	2.4%
Estimated average effect	**0.5 to 1.5%**

Some factors can be addressed by changing early assumptions, but *ALL* can be addressed with as-built performance estimates

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Sub-Optimal Operation

Sub-Optimal Operation: Turbine operation at performance below the potential for the given environment and application.

- ***Lost performance that can reasonably be recovered at a given site***

- Can and does occur
- Not an "availability" issue - by definition, for better or worse
- A variety of causes
- No good means to track
- May be no incentive for some parties to address the issues

Examples of suboptimal operation

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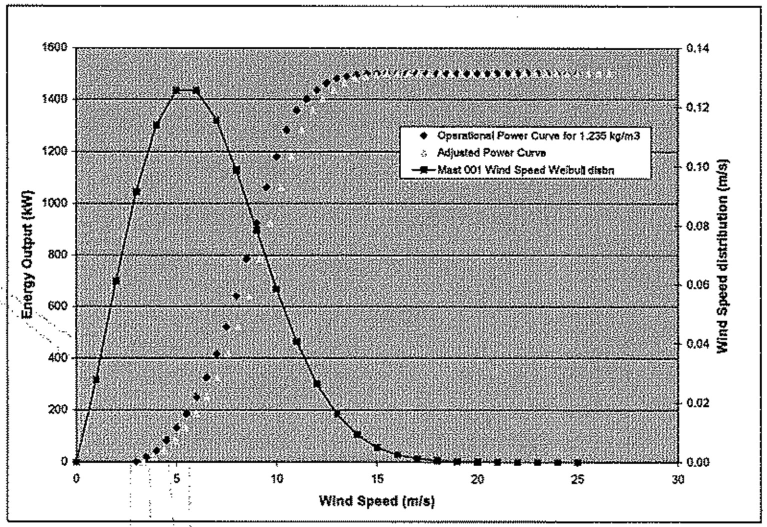
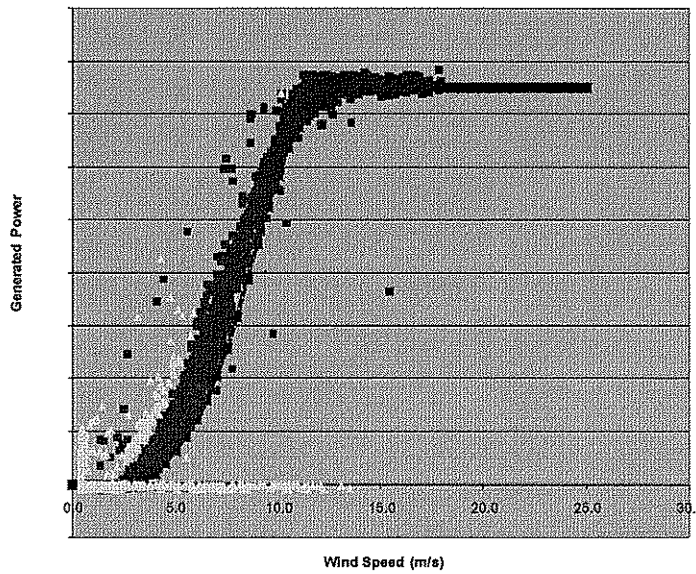
Nacelle anemometer – "incorrect" constants leads to 0.6% shortfall

Nacelle anemometer – undetected soft failure results in untracked downtime





Correctable problems exist

- Often detectable
- May be no incentive for O&M provider to address

Power curves vary
- in time but also turbine to turbine

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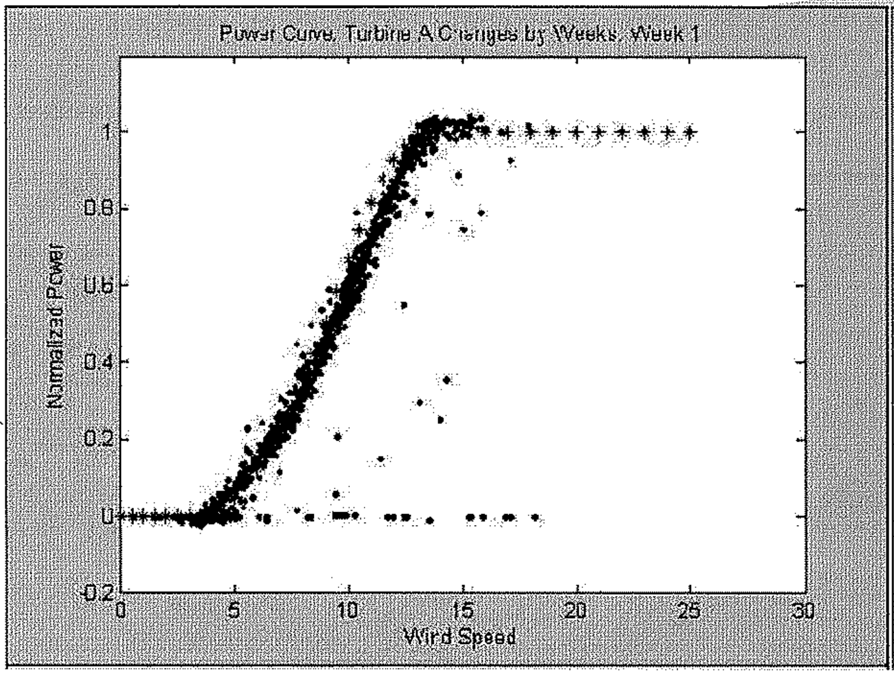

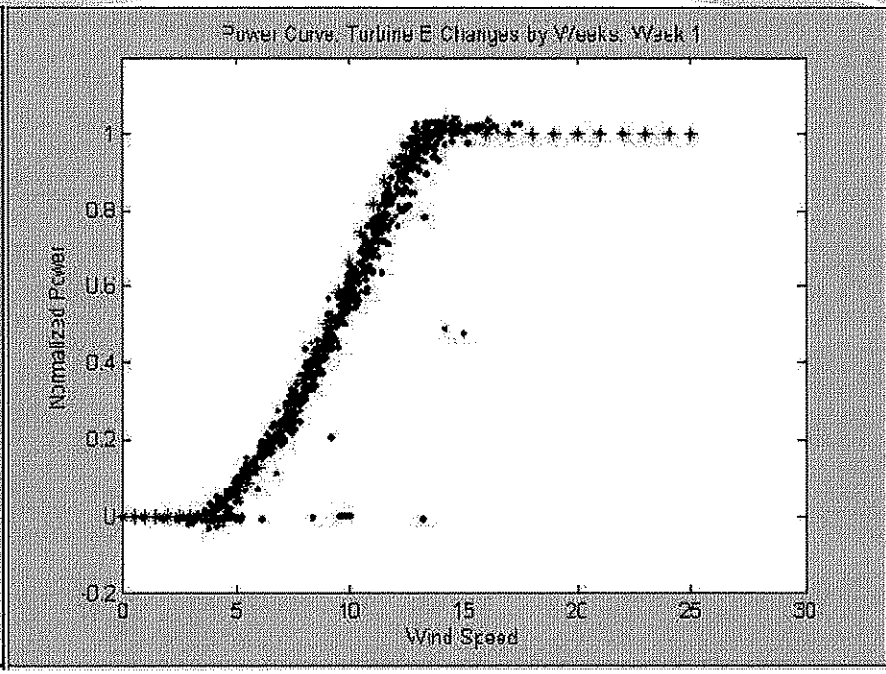

Neighboring turbines show significant variance in power curve shape and values

Clarifying the movement and quantifying the effect thru binned averages

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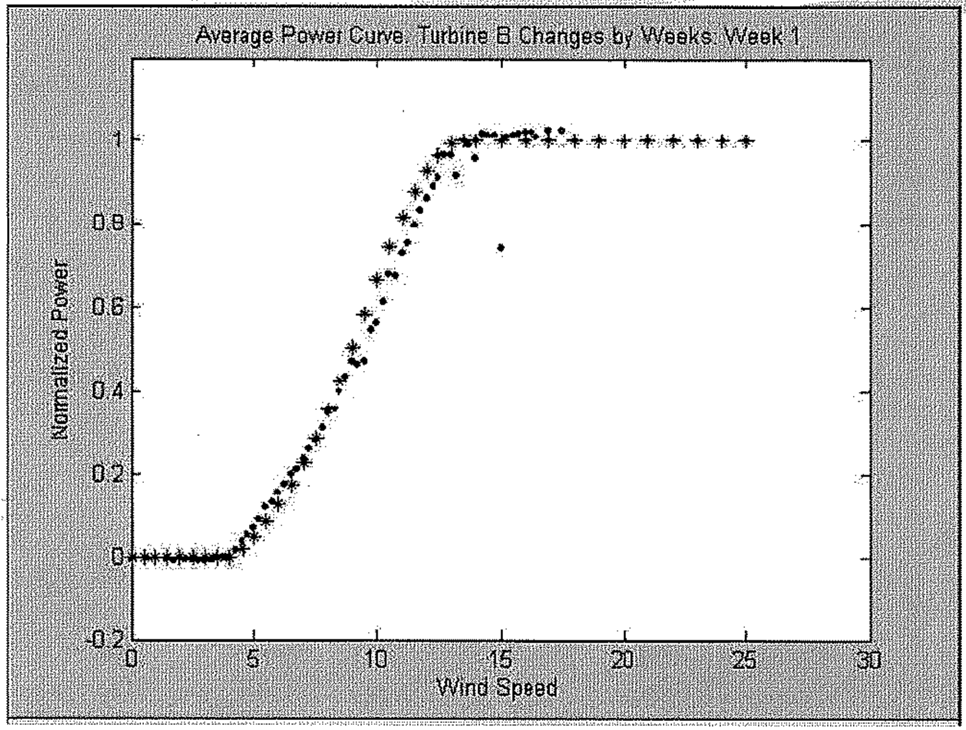

High to low curve on this turbine … a 10% shift in equivalent annual production

Power curve shifts, soft failures and sub-optimal operation will result in lost output

-- *A percent or higher of additional potential in many cases*

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Energy Effects Table

Contributing Element	Rough Estimate of Contribution to Fleet Shortfall
Short Term Climatology	1%
Availability inc. first year effects	3-5%
Resource Assessment Biases	1%
As Built Plant Changes	1%
Sub Optimal Operation	1%
Total	~ 7 to 9%

A significant portion of the exhibited shortfall is accounted for in the above elements

Summary

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- Numerous factors at work in the shortfall
  - Continued investigation needed
- Mother nature plays a role, *but*
  - **Many issues are addressable**
- All parties in the project development chain can play a role in closing the gap
  - Consultants
  - Developers
  - Financial Institutions
  - Owner operators
  - Manufacturers and O&M providers

A CRITICAL GAP IN THE KNOWLEDGE BANK

The wind industry suffers from a persistent gap between predictions of electricity output and actual performance. The average shortfall is 10% in North America. The engineers say they are closing the gap, but investors say not all the way and not soon enough to provide the confidence needed to attract new investment in the current financial climate

JESSE BROEHL
Windpower Monthly US Editor

One of the most vexing and consistent problems to have plagued the modern wind power industry since its birth is the persistent gap between predictions of electricity output from wind farms and actual production from the turbines.

The problem is particularly acute in North America, where despite the entire fleet's broad distribution of various turbines across different regions and weather patterns, wind farms generate about 10% less on average than pre-construction modelling predictions have said they should. Progress has been made towards closing the gap, say the major wind resource assessment specialists, who are confident they are on the right track.

The wind farm investment sector, however, is not fully convinced. Neither are its members pleased with the shortfall. "It's not that it's dramatically harming the economics, but it's just disappointing," says John Eber at J.P. Morgan Capital Corporation. "And it's disappointing because we've been pushing the industry for a couple years now on these observations and we would hope they could just get better at it." J.P. Morgan Capital Corporation is one of the largest owners of wind plant in the US, having been an equity player in the wind business since 2003. It has ownership stakes amounting to 4200 MW—about a sixth of US capacity.

It makes it harder to bring in new investors. It isn't helpful that we can't be a little better at this

JOHN EBER, J.P. MORGAN

No one single smoking gun is to blame for the shortfall, but wind power plant availability—the percentage of time that wind turbines are available to operate provided the wind is blowing—is unanimously considered the largest culprit. Unusually poor winds in certain regions compared with the historical norm is the next most cited reason for the shortfall.

In response to the clear discrepancy between predicted and actual production, wind resource assessment companies have been making adjustments and improvements to the modelling formulas they use for predicting wind plant performance in an attempt to understand the gap and close it.

"I think other investors probably have similar observations. There just may be very few that have this size portfolio that we have," says Eber. "We were one of the first institutions that got into making these investments as a financial investor rather than a strategic owner-operator. We've been at it a little longer and a little broader than many of the other institutions, so we have a good eye on this, given the size of our portfolio."

Eber says the uncertainty about what a wind farm is actually going to produce makes it more challenging to bring in new investors—particularly in the current financial climate—at a time when the wind industry needs a lot more money to continue growing. J.P. Morgan's wind investment model is to use its long-time experience with wind to bring in other investors and the company has leveraged about one-and-a-half times the sum of its own investment in the wind business from outside sources.

UNEASY INVESTORS

"It makes it harder to bring in new investors when you say, well they really don't hit the numbers—on average they're about ten percent off. It isn't helpful for the industry in the long run in terms of raising the large amounts of capital the industry needs, that we can't be a little better at this," says Eber.

Investors, whether providing equity or debt, could decide to do other things with their money that give more predictable returns. Eric White at New York-based wind forecasting company AWS Truewind says many investors have structured deals that shield them somewhat from fluctuating returns, but that the performance gap brings up issues around the time-value of money. "You stay in until you get the target return, so now instead of getting that money, you get it later than expected and you might have invested in something else in the meantime."

Aside from making investors more wary of investing in wind, White says the performance gap slows the ability of utilities to comply with state law demanding an increasing proportion of renewables power. Green power mandates have been passed in 28 states so far. Depending on the wind power content of a utility's green energy portfolio—and it is usually a high percentage of wind—that can mean an unanticipated shortfall in meeting the legal requirements.

"That may mean needing to commission another wind farm to meet the targets, which isn't the end of the world, but it's a ripple down effect if you're not generating what you thought you were," says White. The problem also has a troubling public relations angle, he points out. "There's the whole anti-wind side that says wind plants don't work like advertised. Even if it's marginal and not the end of the world, it still can be picked on."

AWS Truewind and the other major consultancies involved in making wind production estimates for potential investors have been working to improve the accuracy of their projections. Among the market leaders is Garrad Hassan, a British-owned global consultancy. After completing a major global research and validation exercise for its wind production models in mid-2008, Garrad Hassan established there was indeed a gap. The company adjusted some aspects of its approach and its methodology to reflect most recent experience, particularly in North America.

Specifically, Garrad Hassan adjusted its P50 base line representing the primary power prediction figure for the expected mean energy production of a wind plant. The P50, with "P" meaning "probability," represents a 50% probability that the energy production will be higher, or lower, than the prediction. It is the most commonly used

A key issue: *Wind turbines are offline in the United States while they wait for repairs for longer periods than is common in Europe, reducing their "availability" to make money for their owners*

estimate across the wind industry of the long-term average power value expected from a given project.

Garrad Hassan's raw global results have shown that production predictions, on average, have been overestimates. At the 2008 European Wind Energy Conference, results were presented from 486 wind plant years throughout Europe where the average annual production has been 94% of pre-construction projections. In North America, a smaller sample reveals that wind farm production on average has been 90% of pre-construction estimates, news reported by Garrad Hassan at the 2008 American Wind Energy Association annual conference.

The long term predictions of probable wind farm production and resulting revenues are used by project developers as the basis for securing equity and debt financing. Equity investors who own the project, often into the long term, are more prepared to take on risk than debt providers for the project loan. While P50 is the primary measure used by equity investors for how a wind plant will perform, debt providers require greater security and commonly use a P90 or even a P95 standard, meaning that there is a 90-95% probability of the prediction being exceeded. Predictions for debt providers have proved to be very accurate, says Garrad Hassan boss Andrew Garrad.

Debt pays for construction and turbine supply loans. "The debt is only interested in making sure it's paid back," says Garrad. "That debt is issued on the P90, which has a high probability of exceedance. Everybody has exceeded that level. There is not one project that has gone into default and all the low ends of the spectrum are way above what they need to satisfy the debt. As far as estimating for debt, we've done an incredible job for something like fifteen or twenty years. We've done a really good job of protecting the lenders."

Eber says a typical loan structure uses debt coverage ratios (expected cash to service debt) of 1.2x, meaning that a 20% margin is required. "So usually a project can operate as low as P95 before there is insufficient cash to cover the scheduled loan payments," says Eber. "The current average ten percent shortfall being observed in the US is equal to about a P80 performance, so debt service would not likely to be impacted until the shortfall grew closer to P95 performance."

The main problem lies with equity investors and the P50 estimates. At seminars in North America, experts from Garrad Hassan and other wind resource assessment firms have been pooling data and research. "It's pretty alarming on the surface so some big soul searching went on," says Clint Johnson of Garrad Hassan, referring to a series of presentations at recent wind resource assessment workshops.

WHAT IS TO BLAME?

"I think we've done a lot of work as an industry in the last six to twelve months to understand what's going on. The single biggest factor has to do with wind farm availability," says Johnson, referring to the time for which a wind turbine or a wind farm is not shut down for scheduled or unscheduled maintenance. "In short, availability in North America has not been very good. It's been below expectations at around 93% to 94% versus about 97% in Europe, which is really unfortunate because it means we're leaving a lot of money on the table and it means we're over predicting how much wind farms are producing."

Johnson and others believe that a confluence of factors is leading to lower availability in the United States. This includes the relative rush of building that puts a squeeze on the number of technicians available to keep wind plant running optimally. Turbines typically have lower availability during start-up and, with so many new wind farms coming online in past years in the US, it is bound to skew the availability curve. According to AWS Truewind, poor availability accounts for 3-5% of the total production gap, which it agrees lies in the 6-9% range.

Added to the start-up problems, hundreds of new turbines in America have suffered blade quality failures.

The consultancies are not naming names, but there have been much publicised series retrofits of Suzlon and Clipper turbines and less publicised down time for repair work on other makes.

Unusually poor wind seasons play a role too, and this can be worsened in America by the tendency of the US fleet to be clustered in certain geographic areas. Many wind plant were built in West Texas over the past few years and 2005 and 2007 were especially low wind speed years in this region, with 2007 the worst in 15 years. Garrad believes this played a big role in the production gap.

But J.P. Morgan's Eber does not buy the case that poor wind years could have this much of an effect on the P50 because his company's investments are so broadly dispersed between various regions that experience different weather patterns. "Whatever the cause of the fluctuations, if you have forty-three different wind farms spread from Maine to Hawaii, with eleven different sponsors, that you've been investing in for over five years, you would think we would be much closer to the mean, the P50, than where we are," says Eber.

Part of this credit crunch will be to make sure that everything everybody does is done better

ANDREW GARRAD, GARRAD HASSAN

METHODOLOGY IMPROVED

Other reasons for the production gap are each given 1% of the blame by AWS Truewind (table). These include resource assessment biases, often caused when wind speed measuring is conducted at the windiest corner of a site rather than at a location seeing average winds for the area. Older assessments also failed to properly understand complex terrain modelling issues and wake effects in wind farms from turbines disturbing the wind flow for other machines. Unexpected problems during construction, such as crews encountering stubborn bedrock, can mean the wind farm layout being changed to a less than optimal configuration for the prevailing winds. Lastly, suboptimal operation, such as an improperly calibrated turbine anemometer or other faults preventing a turbine correctly yawing into the wind, is also a factor. Better understanding of all of these issues is leading to improvements.

When it comes to causes and solutions, Garrad says his firm and the others disagree only on minor details. He breaks the gap down between three factors contributing about one-third each to the 10% gap: the wind, wind plant availability, and methodology of the measurement and prediction work (box).

Most seem to agree the gap being seen today is partly a vestige of less refined approaches to measurement and prediction years ago compared to what is *de rigueur* today. "A little bit of where we're at is not as bleak as it looks. Most of us have been making changes as we go, trying to improve our methods," says White. "The bulk of the projects we're evaluating...those were designed in 2000 and that's not how we design them today. We've already corrected several percent of the issue at least," says White.

In an attempt to understand the performance gap, AWS Truewind has been conducting a series of studies of past cases that re-evaluate older pre-construction wind power plant data under newer, stricter modelling. The improvements in the newer modelling are clear. "Looking back at that data, I don't get too worked up over how bad I did then, because I wouldn't accept that data today," muses White.

Most of the wind measurement community believes that the gap has largely been solved through the incremental changes made to prediction methodology, but Eber is still not convinced. "They're going in the right direction.

WIND INDEX ADVANTAGE IN EUROPE

JESSE BROEHL
Windpower Monthly US Editor

Accurate predictions of wind plant production in North America are hindered by the lack of a comprehensive and universally respected index of wind strengths built up over many years, say experts. The gap between predicted and actual production in America is almost twice the size of that in Europe (main story), where wind indices have been developed since the 1980s to provide a baseline for how hard the wind is likely to blow in any given area during the assumed 20-year life of a wind plant. Wind indices specially developed by the industry are available in Denmark, Germany, the Netherlands, Sweden and the UK and are calculated from the energy production reports of strategically selected wind turbines (WINDPOWER MONTHLY, January 2006).

Everyone has data they rely on in North America, says Andrew Garrad, head of international wind consultancy Garrad Hassan. "But I think to call it an index is to give it too much credibility." In identifying the performance gap, Garrad Hassan compared all the US wind speed data in 2007 to the best observations taken over 15 years.

The analysis revealed that winds in 2007 were about the same as the 15-year average in some areas, but poorer in others. West Texas, where thousands of megawatt of wind plant operate, saw the worst wind in 15 years. Garrad says that this is one reason for the observed shortfall of energy produced by wind turbines in the American fleet in 2007.

Robust wind indices for different regions of America that most companies can rely on would greatly help in the prediction of wind farm production. But that is a tall order to accomplish for such a large country, admits Garrad. "We have been trying to put one together but because it's such a big place, it's very difficult to do, and I would say that were quite a long way off from having such an index in a reliable form for the US," he says.

But my people cannot find adjustments that appear to be on the scale of the shortfall." Eber says J.P. Morgan has a number of engineers who specialise in banking who have been studying the changes being made to P50 by the independent engineers.

"They are adjusting maybe a third of the shortfall we are observing, so time will tell, but for now, we have not been able to confirm that they really are making the full adjustments," says Eber. "I think part of the problem is they don't really know why the entire shortfall is being observed...and our sense is that until they can identify it, they don't want to start incorporating it into their analysis."

Accounting for the production gap

Poor availability takes most of the blame

REASON	SHARE OF SHORTFALL (ESTIMATE)	APPLIED SOLUTION
Short term climatology	1%	Variance included in uncertainty
Availability plus first year effects	3-5%	Methods corrections
Resource assessment biases	1%	Methods corrections
As built plant changes	1%	Discipline to balance the chequebook
Sub optimal operation	1%	Nothing yet
Overall error range 6-9%		

SOURCE: AWS TRUEWIND

Benjamin Bell, who heads Garrad Hassan in the US, confirms that only the issues and changes that are fully understood and quantified are those being implemented into the modelling protocol. "What we're trying not to do at Garrad Hassan is to give arbitrary haircuts that are not based on science," says Bell. "That's the knee-jerk reaction and the easy thing to do, but actually trying to figure out what's going on and improve the models and get a better understanding of it, that's two different approaches."

Meantime, Eber says his division is looking "a lot harder" at the P50 cases today than in the past and is starting to make adjustments on its own. "I know the engineers haven't been denying what we're observing—and we appreciate that. We just want to keep the message out there that it seems like they are still not there in terms of making these adjustments because it's in the best interests of the industry that they get this right—and it will make it a lot easier to keep the money coming in if we can make these P50 cases more of a reality."

Garrad is more optimistic. "I think the whole industry is tightening up. Ironically, part of this credit crunch will be to make sure that everything everybody does is done better. I think it's been very cathartic to address the problem and everyone is reassured to know that corrective action is being taken on three fronts: better data, better calculations and more attention paid to proper operations."

ATTACHMENT 6 – Sensitivity Analyses Performed by Boston Pacific

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