Portland General Electric Company
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November 16, 2012

Via Electronic Filing and US Mail
puc.filingcenter@state.or.us

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: UM 1182 Phase II
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY'S DIRECT TESTIMONY

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

Original and five copies of Direct Testimony of:
- **Darrington Outama, Ty Bettis, Jaisen Mody and Patrick G. Hager (PGE / 100-102)**

Three copies on CD of:
- **Work Papers (non-confidential)**

These documents are being filed electronically with the Filing Center. Hard copies will be sent via US Mail. An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:jlt
encl.
cc: UM 1182 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY'S DIRECT TESTIMONY (PGE / 100-102)** to be served by electronic mail to those parties whose email addresses appear on the attached service list from OPUC Docket No. UM 1182.

DATED at Portland, Oregon, this 16th day of November, 2012.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1182 Phase II

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

Portland General Electric

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Ty Bettis
Jaisen Mody
Patrick G. Hager

Portland General Electric

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I. Purpose and History of Current Phase of the Docket

Q. Please state your names and positions at Portland General Electric (PGE).

A. My name is Darrington Outama. I am currently a manager in Origination, Structuring, and Strategic Analysis.

My name is Ty Bettis. I am the manager of Merchant Transmission and Resource Integration.

My name is Jaisen Mody. I am the general manager of the Generation Projects department.

My name is Patrick G. Hager. I am the manager of Regulatory Affairs.

Our qualifications are provided in the last section of our testimony.

Q. What is the purpose of your testimony?

A. The primary purpose of our testimony is to address the four items that the Commission has identified for Phase II of this docket – heat rate degradation, cost over- and under-runs, wind capacity factors, and counterparty risk. In particular, for the four items identified, we review whether improvements can be made to the analytic framework and methodologies used to evaluate and compare utility ownership of resources and power purchases from independent power producers (IPP).

Q. Please provide a brief summary of the history of this docket.

A. In Order No. 11-001, the Commission reopened Docket UM 1182 to further examine issues related to the Competitive Bidding Guidelines adopted by the Commission in Order No. 06-446.[1] The Commission identified three specific issues to be addressed.

[1] *In the Matter of the Public Utility Commission of Oregon Investigation Regarding Performance-Based Ratemaking Mechanisms to Address Potential Build v. Buy Bias*, Docket No. UM 1276, Order No. 11-001 at 6 (Jan 3, 2011).

This phase of the docket addresses the third issue: a "determination of the appropriate analytic framework and methodologies to use to evaluate and compare resource ownership to purchasing power from an independent power producer (Guideline 10(d))."[2] At a workshop on November 18, 2011, the parties agreed on a list of twelve factors that might be appropriate for consideration in evaluating the risks and advantages of utility-owned resources compared to those offered by other bidders, such as independent power producers (IPPs), in a competitive bid evaluation process. The parties then participated in another workshop on February 9, 2012, during which they unsuccessfully tried to reach agreement on identifying three factors, from the original twelve, for in-depth consideration. As indicated in the February 22, 2012, Staff Status Report, the parties agreed to submit comments with their respective recommendations on how the Commission should proceed in this docket. After parties submitted comments, the Administrative Law Judge (ALJ) issued a ruling on May 30, adopting Staff's recommendation that the parties initially address three issues from the twelve issue list: cost over-runs and under-runs, counterparty risk, and heat rate degradation. In response to Northwest and Intermountain Power Producers Coalition's (NIPPC) request, the ALJ certified the May 30 ruling to the Commission. In Order No. 12-324, the Commission affirmed the ALJ ruling with the modification to add a fourth issue (wind capacity factor).

Q. What is the purpose of this phase of the docket?

A. The focus is on the appropriate methodology to compare the risks, costs, and benefits of utility ownership and purchasing power from an IPP. In particular, the Commission

[2] ALJ Prehearing Conference Memorandum at 1 (Jan 26, 2011).

opened the second phase to examine the competitive bidding guidelines, namely guideline 10(d). Specifically, the Commission stated:

> "We want a more comprehensive accounting and comparison of all of the relevant risks, including consideration of construction risks, operation and performance risks, and environmental regulatory risks. We also want more in-depth analysis of all of these risks. We invite comment on the analytic framework and methodologies that should be used to evaluate and compare resource ownership to purchasing power from an independent power producer." Order No. 12-324 at 1 (quoting from Order No. 11-001 at 6).

The Commission's immediate concern in this phase of the docket is whether the analytic framework and methodologies used can be improved in four areas: (1) heat rate degradation assumptions, (2) cost over/under-runs, (3) wind capacity factor assumptions, and (4) counterparty risk.

Q. Has the Commission identified any demonstrated biases in analyzing and scoring competitive bids?

A. No. The Commission concluded that the current ratemaking framework could potentially result in bias because the utility earns a return on its own capital investments and not on power purchased from IPPs. (Order No. 11-001). However, the Commission was careful to note that there had been no evidence showing that any bias in analyzing and scoring competitive bids had led to higher cost power for customers. Indeed, the purpose behind reopening this docket was to determine whether competitive bids were being evaluated appropriately and whether the parties could demonstrate any improvements in the analytic framework and evaluation process for reviewing competitive bids. (Order No. 11-001).

Q. How is your testimony organized?

A. Section I is this description of the purpose and history of the docket. In section II, we summarize our testimony. In section III, we outline our competitive bid evaluation methodology and process. In section IV, we address in detail each of the four items that are the focus of this phase. In section V, we provide a summary and our conclusions. We provide our qualifications in section V1.

II. Summary of Testimony

Q. Do you have an overall recommendation concerning the framework for the Commission's examination of competitive bidding guidelines in this phase of the docket?

A. Yes. Ultimately, the debate should not be about the difference between utility-owned versus contract resources. Rather, an effective request for proposal (RFP) bid evaluation process (and any adjustments to the scoring methodology in this process) should be designed solely for the purpose of identifying and accounting for specific resource and bid characteristics. That is, each bid should be scored to capture costs, risks, and benefits to utility customers based on the individual characteristics of that bid, and not on perceived or potential attributes associated with a bid or resource classification (e.g., utility-owned versus IPP owned). Since each electric generation resource, operating environment, proposal, and bidder are unique, the RFP process must be both rigorous and flexible enough to assess bid-specific characteristics and identify and score key areas where risk and value differences exist. If a given bid provides customer protection from risks or a reduced cost, its score should reflect those benefits. Conversely, if a bid does not provide the risk protection or reflects higher costs, its score should reflect that as well.

Moreover, PGE believes that these objectives can be best accomplished through the current basic framework whereby the utilities work with stakeholders, OPUC Staff, and the Independent Evaluator to establish scoring criteria and methodologies for each RFP that both meet the Commission's competitive bidding guidelines, as well as the objectives and criteria set forth in the utility's IRP Action Plan. In order for any future improvements to the RFP bid evaluation process to remain durable over time, this basic framework should be retained.

Q. Do you have any other recommendations?

A. Yes, PGE has two additional recommendations. First, we should avoid generic approaches such as the application of universal adders or bid scoring adjustments based on ownership structure, as doing so would not recognize the unique nature of each bidder and proposal. Applying a uniform adder or bid scoring adjustment would not improve the evaluation methodology and has the potential to prevent the selection of least cost and least risk generating resources for our customers.

In addition, we must also be careful to assess the validity of any potential new bid evaluation methodology that is based on data that may not be relevant with respect to the timeframe and location. To be both accurate and relevant, any data used to evaluate RFP scoring methodologies should reflect the current operating and commercial environment for Northwest utilities and IPPs, as well as the existing Oregon regulatory and policy framework for utility competitive bidding and ratemaking processes. Using historical data that are not relevant to current practice or data from other areas of the country that are not representative of conditions in Oregon would lack analytical rigor and would not provide useful insights about the relative differences between bids for utility owned and contract resources.

Q. What conclusions do you reach regarding the four items being evaluated?

A. For two of the four items (heat rate degradation, and wind capacity factors), our assessment indicates that PGE's RFP evaluation processes and methodologies provide a fair and appropriate approach for evaluating and comparing bid proposals. Thus, we conclude that there is not sufficient justification for change. For the other two items, cost estimates and counter-party risk, we provide recommendations for improvements to the evaluation practice.

Q. What conclusions have you reached related to Heat Rate Degradation?

A. With respect to life cycle plant heat rate degradation, we conclude that life cycle heat rate degradation should be included in utility bid evaluation methodology for any bids where the heat rate is not otherwise guaranteed by the bidder. PGE's competitive bid evaluation methodology appropriately considers heat rate degradation for utility owned generation by including the long-run degraded average heat rate for bid price analysis.

Q. What do you conclude with respect to construction cost over- and under-runs?

A. First, we conclude that the market for power plant construction has advanced and standardized significantly over the last few years and, consequently, that construction cost risk cannot be accurately assessed simply by considering whether the project is utility-owned or an IPP . As a result of this market evolution, the risk of construction cost over-runs to utility customers is largely eliminated. Consequently, we suggest a methodology whereby any bid that includes an overall plant construction cost guarantee (wrap) either by the seller or by a third-party such as an Engineering, Procurement & Construction (EPC) firm should receive a higher bid score than a proposal that does not provide such protections.

Moreover, PGE has seen no evidence to suggest a tendency toward cost overruns for utility-owned plants. In fact, recent PGE bids have consistently come in under budget. These lower costs benefit customers.

Q. What do you conclude regarding wind capacity factors?

A. Regional wind plant generation capacity is growing rapidly. Because of wind power's short operating history, wind industry participants are continuously re-evaluating the performance of wind plants, as well as their impact on the electric systems to which they are interconnected, with respect to predictability and production variability. Recently, the industry has significantly advanced the state of the art in wind forecasting methodology.

We will show that, on a going forward basis, the industry can expect forecasts of wind plant capacity factors to be more accurate for both utility-owned and IPP-owned projects. Further, we anticipate no systematic tendency to over- or under-forecast wind capacity factors in the future. Because all bidders will effectively be relying on the same set of wind forecast tools and experts, there is no reason to differentiate between a utility's proposal and an IPP proposal. We will also discuss the limitations in past wind capacity factor forecasts, how they affect both IPP and utility-owned projects; what the wind industry has learned from its recent experience and, going forward, why we can expect better forecasts of expected wind production from all bidders.

Moreover, we will point out that RFP evaluations do not consider either (i) the benefits to ratepayers if a utility-build project generates more wind than forecasted or (ii) the loss of value to the utility and its customers if a PPA generates less than forecasted. We suggest that instead of attempting to score an RFP bid based on a wind forecast, which by definition is imprecise, the better course is to ensure that RFP bids and the bid evaluation procedures utilize sound and credible forecasting tools.

Q. What will this testimony demonstrate for counter-party risk?

A. We will show that, while PGE's bid evaluation methodology incorporates some of the factors that make up counterparty risk, the methodology could be improved by incorporating additional elements.

III. RFP Process and Framework

Q. What are the primary goals of the resource procurement process?

A. OPUC Order No. 06-446 articulated five goals of the competitive bidding process: (1) provide the opportunity to minimize long-term energy costs, subject to economic, legal and institutional constraints; (2) complement Oregon's integrated resource planning process; (3) not unduly constrain utility management's prerogative to acquire new resources; (4) be flexible, allowing the contracting parties to negotiate mutually beneficial exchange agreements; and (5) be understandable and fair.

Q. Is it a goal of the evaluation process to reduce each bid (regardless of who owns the resource producing the power) to a common point system based on the costs and risks of each bid?

A. Yes. The goal of the evaluation process and criteria is to take into consideration each bid resource's specific characteristics. Each bid is first scored individually based solely on the bid's characteristics and then evaluated as part of the overall utility portfolio to capture the full system costs to customers. A bid's score should reflect the costs and risk of each bid to our customers.

Q. Has the Commission issued guidance to ensure that the RFP process is conducted in a transparent and unbiased manner?

A. Yes, the Commission adopted Competitive Bidding Guidelines in OPUC Order No. 06-446. The guidelines are designed to ensure a fair process. Two guidelines in particular provide a process to ensure that bids are evaluated appropriately in the utility's RFP. These established guidelines are the RFP Design (Guideline 6) and the RFP Approval (Guideline 7). Under these guidelines, the utility provides a draft RFP, conducts workshops for stakeholders and bidders to explain the RFP, and answers any questions pertaining to the draft RFP.

Furthermore, parties can file comments with the Commission to recommend changes to the draft RFP. The utility is required to consult with an independent evaluator (IE) in preparing the RFP and the IE provides a vehicle for bidder communications along with an assessment of the RFP to the Commission. Through this process, the Commission is able to ensure that the RFP is aligned with the utility's acknowledged IRP, that the RFP satisfies the Commission's competitive bidding guidelines, and that the bidding process is fair and objective. The IE is chosen through a competitive and open solicitation that seeks industry expertise in the energy industry and RFP solicitations.

Q. Do these guidelines foster the accurate scoring and evaluation of competitive bids?

A. Yes. As stated above, the Competitive Guidelines allow opportunities for parties to review and comment on the utility's draft RFP. The Commission considers comments and may impose any modifications and/or conditions deemed necessary to have a final RFP that is fair and objective.

Q. Does the role of the IE also promote the likelihood that the RFP process is conducted appropriately and that bids are evaluated accurately?

A. Yes. The Commission selects or approves an IE for every RFP. As stated in the RFP Guidelines (Order No. 06-446), the IE is to oversee the RFP process to ensure that it is conducted fairly and properly. The IE performs the following functions: (1) checking to ensure that the utility's scoring of the bids and its selection of the short-lists are reasonable; (2) working with the utility to reconcile or resolve any scoring differences between the utility's and the IE's bid scoring and evaluation; (3) preparing a final report for the Commission, once the utility has selected a short-list for acknowledgement; and (4) participating in the RFP short-list acknowledgment proceeding if the utility elects to seek short-list acknowledgment. (Guidelines 10, 11 and 13). Additionally, in accordance with the modification of Guideline 13 in Order No. 11-340, the role of the IE can be expanded to include the RFP bid negotiations and final resource selection, should Staff make such a recommendation to the Commission at the time the final short-list is acknowledged. (Order No. 11-340 at 4). Under Guideline 10, if the RFP includes self-bid benchmark options, the IE will independently score the utility's Benchmark Resource and all, or a sample of, the bids to determine whether the selections for the initial and final short-lists are reasonable.

Q. Does PGE's RFP process lead to selection of projects that minimize the cost and risk to PGE's customers?

A. Yes. As stated above, the issue in this docket is whether the evaluation process and methodologies accurately score competing bids during the resource selection process. PGE uses a scoring framework in its RFPs which appropriately accounts for the costs, risks and benefits to customers of each bid. PGE's general scoring framework has been thoroughly vetted with stakeholders in its last two RFPs and was developed with input from Commission Staff and the IE. Expected cost per MWh constitutes the majority of the potential score and risk and other characteristics make up the remainder. Specifically, financial analysis (cost) has accounted for 50% to 60% of the score. Non-price factors have constituted the remaining 40% to 50% of the possible score. These non-price factors include items such as permitting, project financing, fuel supply, electricity transmission, developer / seller credit, and plant characteristics.

PGE continually reviews its bid selection process with regard to ensuring that the value and risks of each bid are accounted for.

Q. Have the IEs concluded that PGE's evaluation methodology and process are fair and unbiased?

A. Yes. PGE's evaluation methodology and process have appropriately scored bids based on their individual characteristics, creating a level playing field for all participants:

- "The RFP evaluation process and modeling treated all bidders fairly." (*Final Report of the Independent Evaluator* at 2, Portland General Electric Company's Request for Proposals for Renewable Energy Resources, OPUC Docket UM 1345 (January 28, 2009))
- "We believe PGE conducted the RFP fairly and without bias towards or against any bidder or type of generation. The criteria and evaluation used to establish the Final Short- list was fully reviewed by the IE, and we found it to be consistently applied to all bids." (*Final Report of the Independent Evaluator* at 26, Portland General Electric Company's Request for Proposals for Renewable Energy Resource, OPUC Docket UM 1345 (January 28, 2009)).
- ". . . in our view, the bid evaluation criteria did not contain undue biases supporting company ownership in projects and actually the criteria may have even been slightly biased against such an option." (*Portland General Electric Company Request for Proposals for Power Supply Resources Final Report of the*

Independent Observer, Merrimack Energy Group, Inc., OPUC Docket UM 1080 at 29 (September 6, 2004)).

- "The evaluation process was a very fair and comprehensive process. In our view, the level of effort and diligence exhibited by members of the evaluation team was extraordinary." (*Portland General Electric Company Request for Proposals for Power Supply Resources Final Report of the Independent Observer*, OPUC Docket UM 1080 at 55 (September 6, 2004)).

Q. How does PGE select which bids make the final short list?

A. The final short list is comprised of the highest scoring bids. The scoring process involves three distinct phases:

Phase I: Each bid is reviewed to determine if it meets the pre-established minimum threshold requirements.

Phase II: Initial Price and Non-Price scores are then determined based on information submitted by the bidders. The resulting ranking forms the basis upon which the initial short list of bids is compiled. Typically, the initial short list will include multiple bids which in the aggregate, represent more than the amount of energy requested in the RFP.

Phase III: Determination of the final Short-List is compiled using a two-step process:

1. PGE conducts due diligence to confirm the bid's credit and transmission / fuel transport arrangements.
2. For bids that remain on the shortlist after PGE has conducted the due diligence described in Step 1 of Phase III, PGE performs a portfolio based analysis to assess the full system cost impact to customers

when combining multiple bids into the Company's existing portfolio. This step captures any synergies resulting from a combination of bids.

Typically, the bids selected for the final short list constitute more than the amount of resource requested in the RFP to allow for the fact that some shortlisted bidders may withdraw from the process or that the parties may not successfully close the negotiations.

Q. Do the scoring criteria assign additional points for ownership to the detriment of PPAs?

A. No. Instead, the scoring criteria are designed to evaluate bids that have the potential to offer the lowest combination of costs and risks from the customers' point of view. The criteria do not assign points based on ownership, but rather, the costs, risks and benefits associated with each structure. For any given factor considered, bids for either utility ownership or IPP ownership could, based on the bid characteristics, receive the maximum score.

Q. How does PGE select the winning bid(s)?

A. PGE uses the scoring process described above to compile a final short list of bids. From this Final Short List, PGE proceeds with negotiations and then selects the winning bid(s) that represent the overall long-term value for customers in meeting their energy and reliability needs given associated risks.

IV. Analysis of Four Identified Issues

A. Heat Rate Degradation

Q. Please explain gas plant heat rate degradation.

A. A gas-fired plant's heat rate is the rate at which the plant converts gas to electricity. The heat rate is usually measured as the ratio of British thermal units of natural gas consumed to kilowatt-hours of electricity generated (Btus per kWh). This ratio is one indicator of how well the plant is performing and is one of the main parameters we use to calculate the cost to operate the plant. Consequently, an accurate estimate of the heat rate is required for an accurate cost estimate and bid.

Like all machinery, and similar to an automobile, a gas plant's level of performance will vary over time; the level of performance may decline in the interval between scheduled maintenance and then recover after the scheduled maintenance. A bid's estimate of life cycle heat rate degradation should reflect both the decline in performance and the recovery achievable with proper maintenance.

Q. Why is this important in the competitive bid evaluation process?

A. In assessing the economic value of a bid, it is important to consider its heat rate throughout the applicable term because this ultimately impacts the cost of the bid. This requires an evaluation of heat rate degradation and periodic efficiency recovery from maintenance over the life of the plant.

Q. Does PGE include heat rate degradation in its evaluation methodology and process?

A. Yes. For its Benchmark projects, PGE includes heat rate degradation in its bid, and also includes the cost of a Long Term Service Agreement (LTSA) needed to maintain the projected heat rate over the life of the plant.

Q. Is heat rate degradation considered for other bidders?

A. Yes. Degraded heat rate information is obtained from equipment vendors, regardless of who is developing the project. These data include the details and costs of an LTSA consistent with the life cycle heat rate assumptions.

Q. Do IPP Tolling Agreements (PPAs) offer guaranteed heat rates?

A. In the current market, bidders offering tolling agreements are not committing to a long-run guaranteed heat rate. Current offers typically include a provision for resetting the offered heat rate on an annual basis after an annual plant performance test.

Q. How are heat rates and heat rate degradation determined?

A. Typically, the turbine manufacturer will provide an estimate of a "new and clean" heat rate and an estimate of "non-recoverable" heat rate degradation. The non-recoverable degradation is the deterioration in plant performance that cannot be reversed with maintenance and will usually be incurred during the first year (approximately) of plant operation. These performance parameters (new and clean heat rate and percent degradation) are typically highly accurate and often form the basis of performance guarantees from the manufacturer.

Q. What other information is required to evaluate the heat rate assumptions in a bid?

A. The bid should incorporate the long run average level of heat rate degradation beyond the non-recoverable amount of heat rate degradation and the details of a maintenance plan that is consistent with the assumed long-run level of degradation.

Q. Did PGE follow this procedure in preparing its bid for the Port Westward plant?

A. Yes. PGE included in the bid the long run average heat rate degradation and the costs of the LTSA agreement consistent with the recoverable performance.

Q. How does PGE ensure its projects are maintained and are capable of operating efficiently?

A. PGE enters into LTSAs with the Original Equipment Manufacturer (OEM). An LTSA provides for parts and labor certainty for maintenance outages *while mitigating cost risks*. It also provides outage guarantees and ensures that the gas turbine is maintained to the highest standards. The LTSA costs are used for calculating and predicting our yearly O&M numbers and are included in our benchmark bids.

For example, PGE has LTSAs for the Coyote Springs and Port Westward generating plants. Both these LTSAs include performing maintenance on the gas turbine at recommended intervals in accordance with the OEM's recommendations. The maintenance intervals include periodic combustion and turbine maintenance followed by an outage termed "Major Maintenance". During this major maintenance, the service provider opens, inspects and repairs or replaces all of the compressor and gas turbine components. Gas turbine components can also be upgraded to current technologies during this outage which could result in improved plant performance. This allows the plant to recover most or all of the recoverable heat rate degradation the plant had suffered over the intervening operating period. PGE plants also utilize water washes and on-line cleaning to reduce degradation.

Q. Has Port Westward's actual heat rate performance to date been consistent with the assumptions made in PGE's bid?

A. Yes. Realized heat rates to date have improved from the long-run average heat rate assumed in PGE's Port Westward bid, meaning that the heat rate degradation forecasts for the Port Westward bid were higher than the actual heat rate experienced. This has resulted in lower power costs for customers.

Q. What conclusions have you reached related to Heat Rate Degradation?

A. We conclude that life cycle heat rate degradation should be included in utility bid evaluation methodology for any bids where the bidder provides no heat rate. PGE's evaluation methodology appropriately considers heat rate degradation for ownership proposals tied to specific generation units and scores the bids accordingly. Using this scoring methodology, the impact of heat rate degradation is directly captured in the cost of the resource, and is also therefore included in the bid overall bid score.

More specifically, PGE's scoring methodology utilizes the long-run degraded average heat rate for bid price analysis. This long-run average is based on technical information available from turbine manufacturers who predict life cycle plant heat rate degradation due to operations, as well as periodic heat rate recovery resulting from unit service / maintenance in accordance with the provisions in typical manufacturer LTSAs – like those currently in place for PGE's Port Westward and Coyote plants. This approach of using detailed heat rate performance projections to establish the expected long-run degraded average heat rate effectively sets tight boundaries on the potential deviation of actual plant heat rate results from initial estimates used in RFP evaluation. As a result, the risk that bid generation fails to achieve the "as bid" heat rate is minimized.

For utilities in Oregon, on a prospective basis, we need only consider the long-run behavior of heat rates for gas-fired plants since, with the exception of biomass, other large scale thermal plants are effectively prohibited by current state policy.

Q. Does PGE's process for scoring utility benchmark bids need to be modified to account for a downward bias in estimates of life-cycle heat rates?

A. No. PGE data show that its bids for benchmark projects incorporate heat rate degradation, and may actually overestimate the amount of heat rate degradation of its plants. Further, the information that the Independent Evaluator (IE) needs in order to audit the utility's heat rate assumptions is readily available. Specifically, the turbine manufacturer's base estimates for a gas plant provide an independent forecast that can be used for this audit.

B. Cost Under-Runs and Over-Runs

Q. How have changes in the power plant market affected the risk of cost over-runs faced by consumers?

A. The market for power plant engineering, procurement and construction has advanced and standardized significantly over the last few years in such a manner that this issue is effectively diffused for both utility-owned and IPP projects. These advancements include readily available products and contract features that substantially mitigate the risk of construction cost over-runs incurred by project owners for power plants. One of the major advancements is the availability of cost guarantees for major components and plant construction from large turbine manufacturers and Engineering, Procurement & Construction (EPC) firms. These guarantees essentially shift construction cost over-runs away from the plant owner to the third-party manufacturer and EPC companies and largely eliminate cost overrun risk to utility customers. The turbine manufacturers and EPC contractors are also typically very large and well-funded entities, so the risk that they would not be able to stand behind the obligations associated with the construction cost guarantees is also very low. Accordingly, for any proposal that includes major component and plant construction cost guarantees (utility owned or IPP), the likelihood that plant construction costs actually paid would materially exceed the cost estimates at the time of bid evaluation is low.

Q. With current EPC practices, should we expect the actual costs of building a power plant to depart materially from the cost estimate submitted with the bid?

A. No. Under current EPC practices, a large fraction of total construction cost is covered by cost guarantees provided either by the equipment manufacturer and / or the EPC contractor. The residual risk in the cost estimate is very small. PGE uses the fixed price lump sum approach for large projects where the fixed price is obtained in a competitive bidding process. Such a fixed price contract insures against the many uncertainties (for example, material and project cost escalation) that could occur during project execution.

Q. Please discuss the types of construction cost guarantees that are typical of current contracting practice.

A. For a gas plant, PGE can expect to write a detailed specification that is reviewed by our operation and maintenance team. This specification would address plant design, equipment procurement, construction, commissioning and startup. The contractor then provides a fixed price bid backed with contractual guarantees. No other price adders are permitted except for approved change orders. PGE project management team then manages the change order rate to below industry standards during project execution.

Q. How does PGE manage EPC cost?

A. PGE hires experienced and qualified EPC contractors, and uses commercially proven generation technologies. This development expertise is combined with the company's internal and external experts in project management. By managing project development in this manner, PGE has been able to keep both owner requested and contractor requested change orders below the industry average. For Port Westward the change order rate was below 2% and for Biglow Canyon it was 1%.

Q. Do you have a recommendation on how to improve bid evaluation / scoring?

A. Yes. Despite our assessment that this risk can be substantially mitigated through readily available products, PGE agrees that construction cost risk should be included in the bid evaluation process. We would suggest an approach whereby any bid that includes an overall plant construction cost guarantee (wrap) either by the seller or by a third-party such as a first tier EPC contractor should receive a higher bid score than a proposal that does not provide such protections. Further, any bid that provides a guarantee and/or contract protections for cost increases that are limited in amount, therefore leaving a material residual risk of cost increases with the plant owner, would receive a lower score than a bid providing a full guarantee. An appropriate scoring methodology for this item should also consider whether the construction cost guarantor has the financial ability to stand behind the potential liability associated with the guarantee.

Q. Are there any other factors that you would consider incorporating into the bid evaluation regarding this item?

A. Yes. While construction cost and performance guarantees substantially mitigate cost over-run risk faced by PGE's customers, ownership proposals still permit customers to benefit from cost savings if actual plant construction costs are lower than the projected cost at the time of bid evaluation. When PGE completes a utility ownership project under budget, the cost savings flow to customers through a reduction in energy costs. While we recognize that end effects are not among the issues to be examined in this phase of the docket, we believe that the residual value and optionality associated with owning a generation project offers the potential for considerable additional value beyond the projected useful life to the plant owner (or in the case of a utility, to its customers), and that this value should be incorporated in the evaluation and selection of new resources.

In addition, the current regulatory framework also provides utilities with strong incentives to avoid cost over-runs and seek third party construction price guarantees; given that rate recovery mechanisms offer multiple layers of prudency review and customer protections.

Q. Do customers similarly benefit if an IPP plant is built at less than the assumed cost in the IPP bid?

A. No. If an IPP plant is built at less than the cost assumed in the IPP bid, all of the benefits go to the IPP. The point of comparing the impact of these "under budget" scenarios is that the evaluation methodology and process requires no adjustment as long as there is no evidence of a systematic trend of cost over-runs or cost under-runs for utility ownership projects.

Q. Does PGE's experience with utility ownership projects support PGE's approach of not assessing a premium or penalty against utility-owned projects?

A. Yes. The initial cost estimate for Port Westward was $298.2 million. However, the estimate PGE filed in UE 180 was $285.2 million and the final installed cost of $279 million represented a net cost savings for customers of 6.4%.

Q. Was PGE's experience with the Biglow Canyon plants similar?

A. Yes.

- The cost estimate for Phase I of Biglow Canyon was $261 million. The final installed cost of $256.5 million represented a net cost savings of 1.7%.
- The cost estimate for Phase II of Biglow Canyon was $325.5 million. The updated estimate was $321 million and the final installed cost of $318.4 million represented a net cost savings of 2.2%.
- The cost estimate for Phase III of Biglow Canyon was $428.4 million. PGE and parties settled on a $34.6 million reduction in rate base and the final installed cost of $383.7 million represented a net cost savings of 10.4%.

Q. In light of this, should PGE change its procedures for evaluating cost estimates in bids?

A. Yes. While PGE's practice in scoring bids evaluates construction costs, modifying the approach to account for whether or not a bid includes a full wrap or cost guarantee would reduce the risk of material cost over-runs to PGE's customers.

Q. Did PGE receive performance guarantees when it built its Port Westward plant?

A. Yes. For example, after signing a fixed price contract with Black & Veatch for the Port Westward plant, the market for gas turbines and combined cycle plants improved significantly causing market prices to increase. However, PGE's contract insulated the Company and our customers from market price increases as we had locked in a price guarantee. The project subsequently came in under budget.

Q. Knowing PGE has historically brought plants on-line at costs lower than the estimate in PGE's bid, is it logical to apply a uniform average capacity cost adder to PGE's future benchmark bids?

A. No. To apply a price adder as a method to recognize risks that have not been experienced by the utility's customers, but are based on generic industry experience, makes no logical sense.

C. Capacity Factors for Wind Resources

Q. Has there been a change in best practices within the wind industry regarding wind plant availability numbers in production estimates? If so, what has brought on this change?

A. Yes. The U.S. wind industry has discovered factors that affect wind turbine availability that are unique to the U.S. For instance, the typical size of a wind plant (or farm) in the U.S. is much larger than a wind plant in Europe. This size difference affects maintenance schedules, curtailment impacts, and the effect of cutouts due to high wind speeds. Other factors, such as geography and turbine size can also affect availability. The current gross availability number used for production estimates in the U.S. is 95.3%.

Q. Are there any other factors that might result in a difference between the production estimate and the actual generation of a wind farm?

A. Yes. The wind industry has discovered other factors that can cumulatively affect the difference between the production estimate and actual production. One major factor is the impact of the wake created by the turbines themselves. Wind farm layouts are created to maximize the output of the plant by minimizing intra-farm wakes. Feeders, or lines of turbines, are lined up perpendicular to the prevailing wind in order to capture as much of the energy from the wind as possible without creating a wake on the next turbine in line. When the wind shifts and comes in parallel to the feeder, a wake is created down the line of turbines that reduces the output of the entire feeder. This wake effect can also be caused by new wind plants that are upwind from existing wind plants.

Other factors that can contribute to the difference between the production estimate and actual generation are weather-related (such as icing on the blades, sand and grit build-up, and lightning strikes), biological interference (gophers, avian), and a lack of high quality, long-term reference sites.

Q. What effect have these changes had on the development of annual wind production estimates for wind farms?

A. According to a presentation made by Michael Brower of AWS (see PGE Exhibit 101), which compared annual wind production assessments made pre-2008 to actual production, the US wind industry has underperformed by approximately 10%. The presentation also discussed GL GH's history of underperformance. Both companies have publicly stated that their current assessment capabilities have improved significantly in recent years due to improved analytical techniques and more plant operating experience. Using an improved assessment methodology (see PGE Exhibit 102), GL GH reran the same 152 wind farm years they used to verify their past assessment accuracy. This new assessment methodology has reduced underperformance expectations from 9% to 0%.

Q. Do these improvements in the current production estimate development process undermine the idea of applying a bid adder to utility-owned wind?

A. Yes. There is no need to penalize the utility-owned wind plant bids to compensate for an underperformance in historical production estimates. The wind industry has adjusted and matured in this regard and to apply an adder going forward would simply be over-compensating for a problem that has since been resolved.

Q. Please describe the risks to consumers if the actual capacity factor for a Utility Owned Generation (UOG) wind plant is less than projected in the bid.

A. If the UOG wind plant underperforms compared to the forecast, then the average cost per MWh from the project would be higher and the project would produce fewer Renewable Energy Certificates (RECs) than projected. Depending on the treatment in cost recovery proceedings at the Commission, these costs may be passed on to customers.

Q. Are the risks associated with a lower-than-forecasted capacity factor balanced by potential benefits to customers if the actual capacity factor for a Utility Owned wind plant is greater than projected in the bid?

A. Yes, our customers would benefit in this scenario. If a UOG wind plant performs better than forecasted, the average cost per MWh from the project would be lower and the project would produce more RECs and energy than projected. The additional RECs would either reduce the need to purchase or produce RECs in the future or, if sold, would produce incremental revenue. Our customers would benefit from the cost savings or incremental revenue through PGE's ratemaking processes, (AUT and PCAM).

Q. Are PPAs similar in terms of the potential countervailing risks and benefits from greater-than-forecast and less-than-forecast capacity factors for wind plants?

A. Yes, customers still face risk when wind capacity factors are less than forecasted. However, it is less clear that customers will benefit when wind capacity factors are greater than forecasted.

Q. Please explain.

A. Under a fixed price PPA contract, when the wind plant underperforms the IPP's capacity forecast, customers could face cost risk if the utility needs to purchase RECs or replacement qualified green energy in order to meet its RPS requirements. Additionally, customers could face cost risk if the utility needs to purchase additional energy to meet its load requirements due to receiving less wind energy than forecast when market energy prices are higher than the PPA energy price.

Q. Please describe the impact on customers if the actual capacity factor for a PPA wind plant is greater than projected in the bid.

A. Under a fixed price PPA, the utility and its consumers would purchase more energy and would receive more RECs than expected. The excess energy production and contract payments may or may not be a benefit to customers. If the PPA price is higher than the short-term market price for electricity (which is likely in today's environment), power costs would be greater than expected.

Q. What is your recommendation regarding scoring and evaluation of UOG and PPA wind projects?

A. As previously stated, we believe that each bid should be scored based on that bid's characteristics and the costs and risks it would impose on consumers. Given that the wind industry in the United States has improved its forecasting methodology and that both PPA and utility-owned wind projects impose risks and provide benefits to consumers, we believe that no bid premium for a utility-owned project is warranted.

D. Counterparty Risk

Q. How does PGE define counterparty risk?

A. Counterparty risk refers to the risk associated with the counterparty's failure to execute the transaction and/or nonperformance of its contract obligations. There are two primary aspects of counterparty risk, both of which can have significant impacts on the utility and its customers. The first is the risk that a counterparty will become unwilling or unable to perform some or all of the provisions of a specific contract due to a change in external environment or circumstance that adversely impacts the economics of the transaction. This risk is referred to as transaction-specific risk. For example, in the case of unexpected capital additions, there may be a risk that an IPP has the contractual ability to terminate, renegotiate, or pass the cost through to the buyer under a PPA if a major non-elective capital addition is required on the generation resource underlying the PPA.[3] Even in the absence of such contractual rights, it would be important to evaluate the risk that, if the cost of a capital addition is large enough, the counterparty could elect to breach the agreement, initiate a legal dispute or be forced to file for bankruptcy. In other words, because IPPs are typically not regulated by the Commission, an IPP's guarantee to keep the utility and its customers insulated from any unexpected cost or supply deviations is only as good as the level of collateral offered by the counterparty or its parent company at any particular time and the ability of the utility to perfect its security rights in a legal proceeding. Even if a selling counterparty was large enough and exhibited the financial

[3] Costs determined as prudent that are passed through to the utility, as buyer, would subsequently be passed through to customers.

wherewithal to insulate a purchasing utility from all of the risks associated with the generation and delivery of electricity, no prudent organization would do so. If adverse circumstances encountered by the seller / generation owner resulted in significant financial losses due to continued contract performance, elective or forced default would likely occur.

Another possibility is a situation where a counterparty encounters a problem with the development or construction of a new generation project (e.g., inability to obtain all necessary permits or acquire acceptable financing), and is able to avoid performance requirements and/or damages through a condition precedent clause (these are common provisions in contracts associated with generation projects that are not yet built). Similar contractual rights that excuse performance exist for significant and unforeseen problems that could be encountered for a contract with an existing generator (e.g., force majeure). Another example is a no-damages provision that excuses performance, provides for a change in pricing and/or allows for a no-damages termination if a significant, unforeseen event such as a change in environmental law or regulation is encountered. This type of provision is becoming more common in long-term wholesale energy contracts to address the potential for significant changes in future environmental regulations (e.g. regulations pertaining to CO_2 and greenhouse gas emissions).

The second primary area of counterparty exposure is financial risk – the risk that a counterparty will no longer be able to fulfill many or all of its contract obligations due to insolvency or a material deterioration of the organization's financial condition.[4] This type of counterparty risk is commonly referred to as "Credit Risk."

Q. Does PGE currently include counterparty risk in its bid scoring?

A. To some extent. In its scoring and evaluation criteria PGE considers Credit Risk which is only one component of Counterparty Risk. PGE also accounted for a limited aspect of counter-party risk (experience of the project development team) in our 2007 Renewable RFP scoring.

However, this scoring element does not capture the risk that the counter party will not be able to fulfill its obligations due to insolvency or a material deterioration of its financial condition or other changed circumstances. We do not score and evaluate these other types of counterparty risk.

Credit risk, which is another element of counterparty risk, refers to the risk associated with the counterparty's financial strength. Specifically, PGE's bid scoring criteria consider the creditworthiness ("credit evaluation") of a bidder based on its ratings from the main ratings agencies (S&P, Moody's, Fitch, or DBRS) and the finance ability of the project ("development viability").

Q. How does PGE consider credit risk in the bid scoring?

A. The overall financial strength of the bidder has to meet a certain threshold to qualify. Bidders must be at least investment grade as rated by one or more of the major credit rating agencies. Alternatively, bidders can meet this requirement through the issuance of a parental guarantee from an investment grade entity or a Letter of Credit issued by a

[4] It is common that an IPP will form a limited liability corporation (LLC) and place the assets underlying a PPA in the LLC. By doing so, the IPP / parent company is protected should the LLC fail.

qualified financial institution. Once this threshold is met, the bid can proceed to the scoring stage where a bid's score is based on its credit rating.

Q. Why should credit risk be assessed twice, once as a threshold issue and again in the scoring criteria?

A. Since credit plays a crucial role in an entity's ability to bring a project to fruition and meet the ongoing operational and performance requirements of a contract, seller credit is a critical issue and must be considered on a threshold basis. There would be no reason to score a bid if the credit threshold were not met. Scoring credit risk allows those qualifying bids to be differentiated based on their relative credit profile.

The credit threshold can be met if the bidding entity is rated as investment grade or through a parental guarantee. In addition, PGE provides alternatives for non-investment grade companies to meet the threshold. If credit was only treated as a threshold issue, the scoring criteria would essentially assess the credit risk of an "AAA" senior unsecured debt rated multinational-corporation as the same credit risk profile of a small start-up with a Letter of Credit issued by a qualified financial institution. That would not be appropriate. The additional granularity of scoring beyond threshold requirements enables us to differentiate bidder credit profiles and associated risk to customers.

Q. Do PPAs typically contain provisions that protect PGE and customers from the risk of a seller's default?

A. Only partially. We must also keep in mind that wholesale energy contracts provide for a monetary remedy (financial damages); thus, the remedy will not be available for the purchaser to compel the seller to continue to deliver electricity or capacity in accordance with the terms of the agreement. Since typical PPA credit and collateral provisions only account for a portion of the full financial risk of replacing a long-term, significant contract, utility customers would ultimately bear both the supply and financial risk of counterparty performance failure and default.

Q. Are there other provisions in RFPs that directly impact counterparty risks?

A. Yes. Consistent with the Commission's Competitive Bidding Guidelines, bidders can modify or delete PPA contract provisions. Bidders could also state that language of certain provisions will be determined during contract negotiations. Since these provisions are only finalized during final contract negotiations, it means that contract provisions and customer protections that PGE believed are included in a PPA bid, and on which basis the bid is scored, may not be included in the final contract. As a result, the score on which a PPA was selected for the final short list may not correctly reflect its costs and risks.

Q. Do you have a proposal to remedy this issue?

A. Yes. We recommend that key provisions in PPAs should be non-bypassable. That is, counterparties would not be able to modify key provisions that impact counterparty risk.

Q. Does the scoring differentiate between ownership structures?

A. Only in a specific circumstance. The threshold and total scoring criteria is the same for all bids regardless of ownership structure (utility or IPP). There is an exception made for sellers that are not investment grade who are selling an existing asset. Because that risk profile is so finite, the threshold is waived, but not the scoring criteria.

Q. How would PGE propose to fix this discrepancy in counterparty risk?

A. PGE would propose that Ownership bids be allocated the maximum credit risk score and that additional elements of counterparty risk should be added to the scoring criteria.

V. Summary and Conclusions

Q. Please summarize the key element of a fair RFP bid evaluation process.

A. A fair and effective RFP bid evaluation process should be able to identify and account for specific resource and bid characteristics. That is, each bid should be scored as to costs, risks and benefits to its customers based on the individual characteristics of that bid, not on perceived or potential attributes associated with a bid or resource classification (e.g., utility owned versus IPP owned).

Q. Please summarize your conclusions regarding PGE's RFP bid evaluation process.

A. We conclude that PGE's bid evaluation and selection methodology appropriately accounts for the costs, risks and benefits that bids would impose on utility customers. However, we believe that scoring of construction cost risk and counterparty risk could be augmented as described above.

Q. Please summarize your recommendations to the Commission.

A. First, we recommend that the Commission continue to maintain its focus on potential improvements in the analytic framework and process for RFP bid evaluation. The debate should not center on utility-owned generation versus contract resources, but rather the objective should be to improve the evaluation and scoring process to ensure that bids are appropriately scored and the proposals which represent the best combination of cost and risk for customers (based on IRP requirements) are selected. Any improvements in the evaluation methodology should be sensitive to the fact-specific nature of the process and should avoid a one-size-fits all "adder" approach.

Second, we recommend no change in PGE's evaluation methodology for two of the four factors: (heat rate degradation, and wind capacity factor). We recommend some potential improvements for counterparty risk and construction cost estimates.

Finally, if the Commission finds that improvements are needed for any of the four issues identified for this phase of the docket, we recommend an approach whereby the Commission directs the IOUs to work with the IE and Staff to develop scoring criteria to address the costs, risks and benefits imposed on utility customers for each specific issue. This approach would ensure that the RFP bid evaluation and scoring process remain flexible and adaptable to recognize the differences in each RFP (e.g., renewable versus thermal) and each utility's IRP Action Plan requirements.

VI. Witness Qualifications

Q. Mr. Outama, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from University of Washington in 1996. I have over 15 years of experience with PGE working in accounting, financial planning, risk management and power operations. I am currently managing the Origination, Structuring and Strategic Analysis groups. In addition, since 2011, I have led the effort to complete PGE's Request for Proposal to procure resource to meet customers' needs as identified in the acknowledged 2009 IRP.

Q. Mr. Bettis, please describe your qualifications.

A. I graduated from Warner Pacific College in 1997with a Bachelor of Science degree in Business Administration. I received my Master of Science degree in Management and Organizational Leadership from Warner Pacific in 2009. I have been employed by Portland General Electric Company (PGE) for over 23 years. I am currently the Manager of Merchant Transmission and Resource Integration for Portland General Electric Merchant. I currently serve on the Board of Directors of the Utility Variable-Generation Integration Group and represent PGE on the NW Wind Integration Forum Technical Working Group.

Q. Mr. Mody, please describe your qualifications.

A. I am the General Manager of the Generation Projects department, the group responsible for managing the development of large generation projects. I have over 38 years of experience in management, operations, design and construction of Power Plants. I am a registered Professional Engineer in Oregon and hold a M.S. degree in Mechanical Engineering from the University of Washington.

Q. Mr. Hager, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts. Between 2002 and 2007, I served on the Advantis Credit Union Audit Committee and I now serve on the Board of Directors.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	AWS Truepower Risk Management Presentation
102	GL Actual vs Predicted Performance Presentation

UM 1182

Exhibit 101

Provided in Electronic Format (CD) Only

AWS Truepower Risk Management Presentation

UM 1182

Exhibit 102

Provided in Electronic Format (CD) Only

GL Actual vs Predicted Performance Presentation

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March 2011

What do you mean you're not sure?

CONCEPTS IN UNCERTAINTY AND RISK MANAGEMENT

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Uncertainty is a part of life

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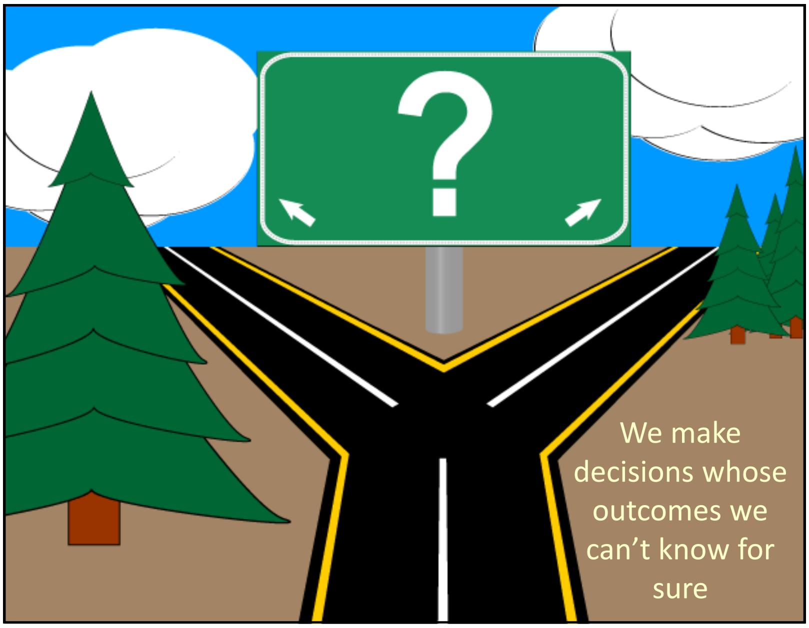
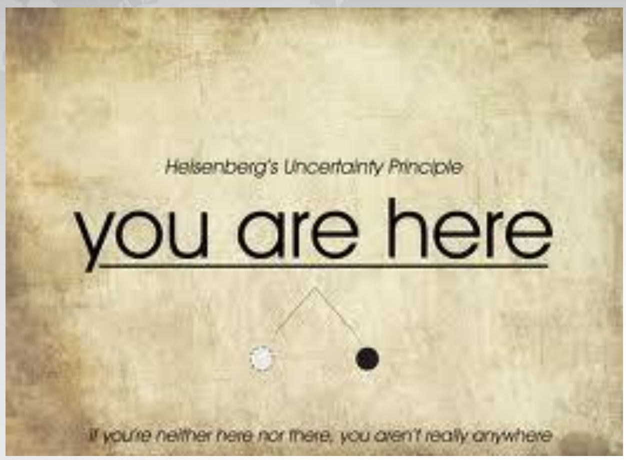
UM 1182 / PGE / Exhibit 101
Outama - Bettis - Mody - Hager
Page 2


?
We make decisions whose outcomes we can't know for sure


JOSEPH GORDON-LEVITT LYNN COLLINS
UNCERTAINTY
A FILM BY SCOTT MCGEHEE & DAVID SIEGEL
OFFICIAL SELECTION TORONTO FILM FESTIVAL 2008
GWYNETH PALTROW
SLIDING DOORS
Uncertainty pervades our culture, from movies...



...to science.

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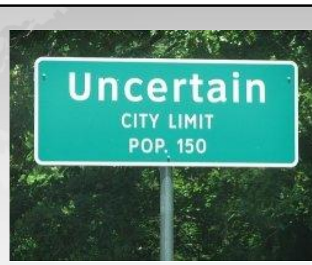
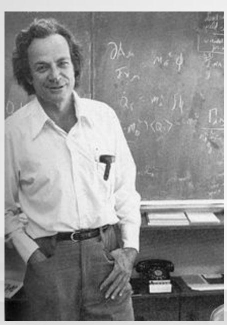
Some people live happily with uncertainty…





"I can live with doubt, and uncertainty, and not knowing....It doesn't frighten me."
Richard Feynman, *The Pleasure of Finding Things Out*

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…others have more trouble with the concept

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Uncertainty is also part of a wind project's life

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Will my turbines
perform well?


Will it be as windy in
the future
as it was in the past?

Considering all *possible* outcomes is necessary but not sufficient

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Unless you can *quantify* the uncertainty, your estimate of the future energy production of a wind project *has no value*

…blindfolded

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So let's define some terms

A working definition of uncertainty:

The range of likely future outcomes

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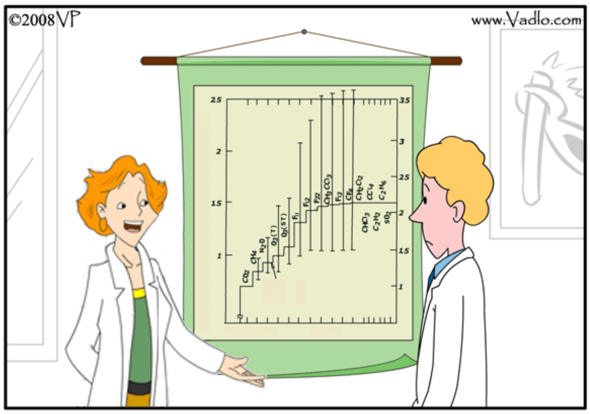
Sometimes this takes the form of error bars…



Did you really have to show the error bars?

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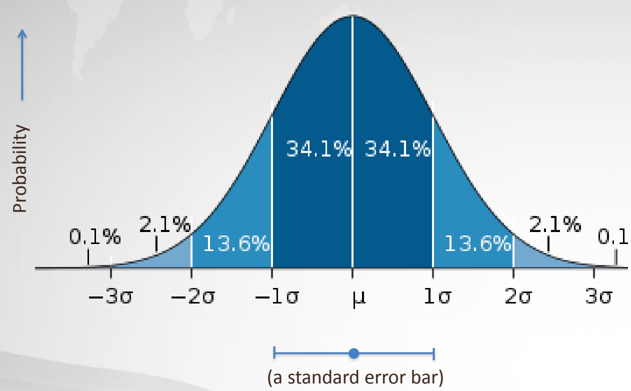
…or better: as a probability distribution



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By the way, don't confuse uncertainty with

Error

The difference between a single outcome and your prediction (some error is unavoidable)

Bias

The tendency towards a certain direction and magnitude of error over many predictions (this means you screwed up)

Risk

The impact of uncertainty on something you value, such as profits

We'll get back to them later

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However it's communicated…

Uncertainty analysis involves estimating the probability of different outcomes

But how?

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Here's a typical procedure

- First, define the parameter you're interested in. Let's say it's energy production.
- Second, define the elements that can affect the energy production.
- Third, estimate the uncertainty of each element.
- Fourth, combine the uncertainties.

We'll go through steps 2-4

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Defining the elements that contribute to uncertainty in energy production requires creating a model, like this one:

$$Power = \sum_{i=1}^{8760} \overset{\text{Power curve}}{P}(\underset{\text{Air density}}{\rho_i}, \underset{\text{Speed}}{v_i}) \cdot (1 - \overset{\text{Losses}}{\epsilon_i})$$

Is your model complete?
(Hint: Models never are.)

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Now let's consider ways of estimating each uncertainty element (in order of decreasing confidence)

- Prior experience or measurement
  - Variability measured or observed directly in the past and which you have a reasonable expectation will apply in the future
- Extrapolation or inference
  - Extrapolated or inferred from observations of similar or related systems
- Educated Guesswork ("Expert Judgment")
  - Assessment of possible scenarios informed more or less by experience or theory

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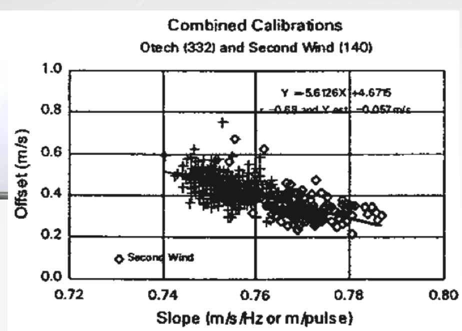
In fact, most uncertainty estimates reflect a blend of approaches. Anemometer uncertainty is estimated based partly on prior experience…

NRG Systems



Bailey & Lockhart (1998)

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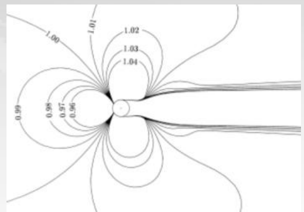
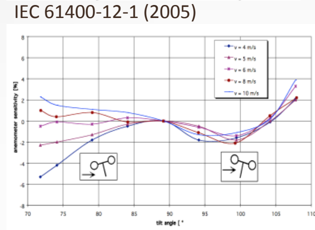
…and partly on inference from field conditions, such as:

Tower effects



IEC 61400-12-1 (2005)

Inflow angle



IEA (2003)

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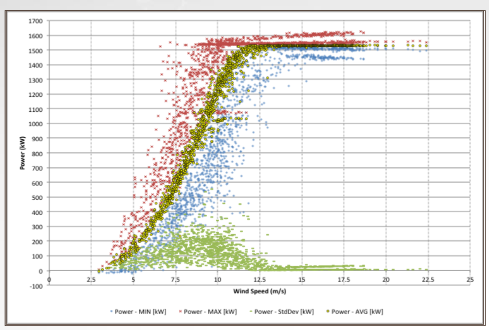
Turbine performance uncertainty is likewise based on a combination of prior experience and inference

The idealized picture of a turbine power curve…

…often looks much different in reality



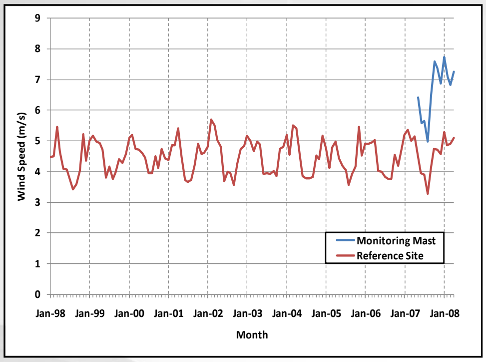
AWS Truepower

What causes such variability is a matter of debate – all the more reason to consider this an uncertainty

AWS Truepower

12/14/2011

Uncertainty due to natural wind climate variability is almost entirely inferred from measurements at other locations (the MCP process)…



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…and when it comes to the effects of climate change, we're in the realm of educated guesswork

Climate Scientist

=

Fortune Teller

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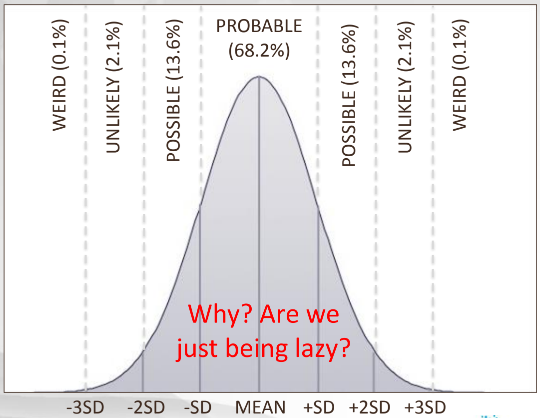
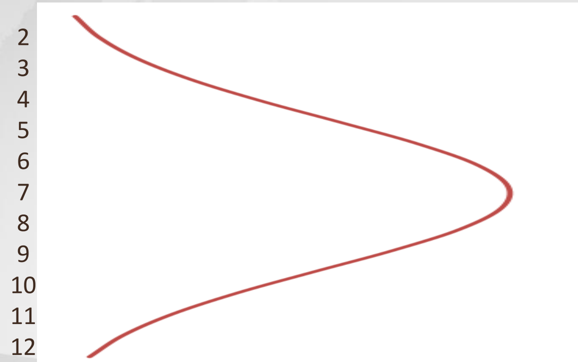
However derived, the uncertainty is very often represented by a *normal distribution*



Normal distributions:

- Intuitive
- Convenient, analytically tractable
  - Fun Fact #1: The mean and standard deviation of a normal distribution capture all possible combinations of range and probability
- Apply to a wide range of problems
  - Central Limit Theorem: The sum or mean of a sufficiently large number of independent observations approaches a normal distribution
  - Fun Fact #2: It doesn't matter (almost) what the underlying distribution is!

If you’re skeptical, consider all the possible combinations of a throw of two dice



Extend this to many dice, and you have a perfect normal distribution

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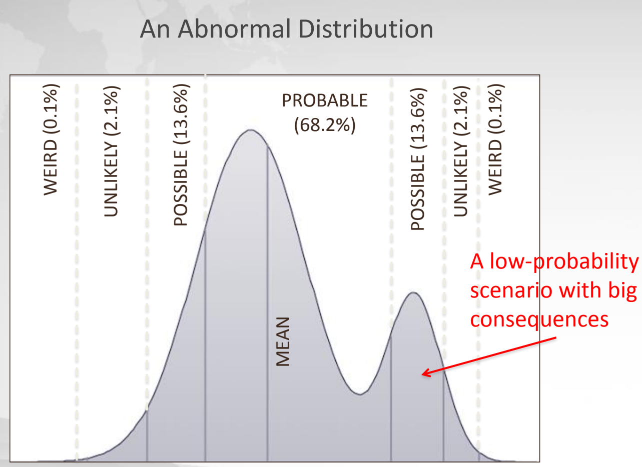
But not all distributions are really normal



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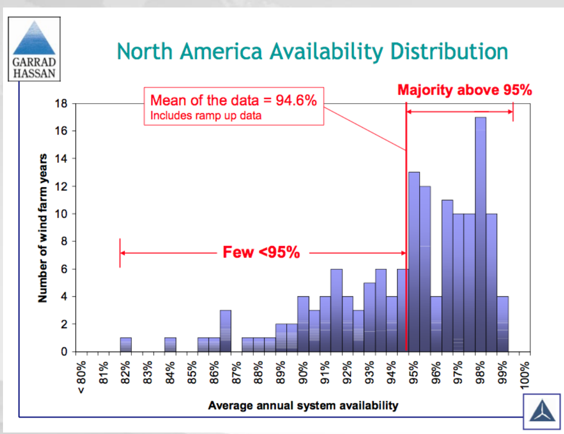
Like a tornado

Plant availability: the most important non-normal distribution



Source: GL Garrad Hassan,
Availability Trends in the US (2009)

How do we combine uncertainties?

Much depends on whether different sources of error are *correlated* or *uncorrelated*

- Uncorrelated errors vary independently of one another.
  - A positive error from one source is often offset by a negative error from another source.
- Correlated errors vary in lock step with each other
  - No offsetting occurs

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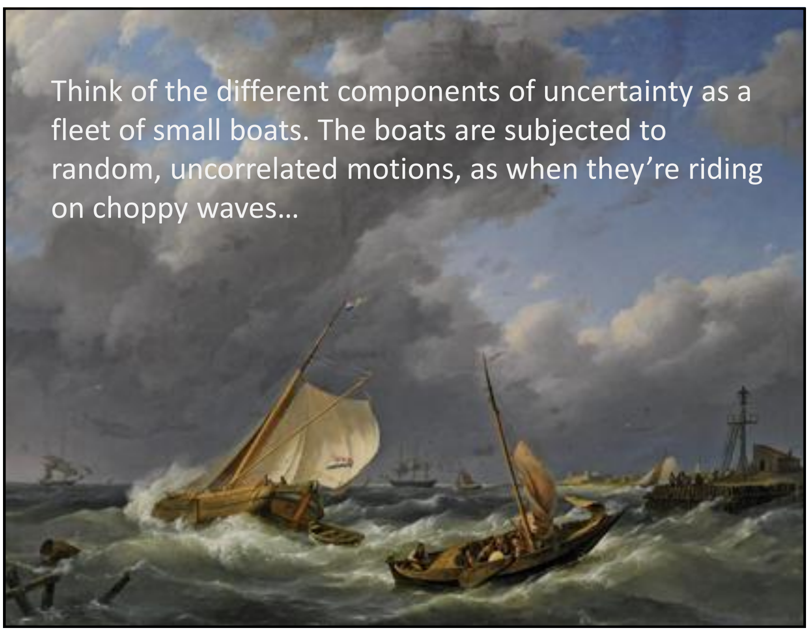

…and they rise and fall with the tide, in a correlated way

A Big Impact

Different correlated uncertainties add linearly

$$2\% + 2\% = 4\%$$

Different uncorrelated uncertainties add as the "sum of the squares"

$$\sqrt{2\%^2 + 2\%^2} = 2.8\%$$

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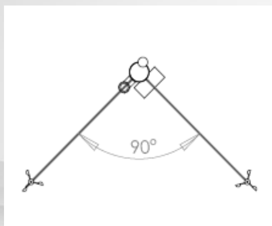
A special case is when you measure the same parameter with different instruments:

The combined uncertainty for multiple independent measurements is reduced by the square root of the number of measurements:



$$2\% / \sqrt{2} = 1.4\%$$

The Lesson?

Try to measure the wind resource in as many *independent* ways as possible

It's safe to assume that *most* uncertainties in wind resource assessment *for a single mast* are uncorrelated and therefore add as the sum of the squares

Sum of Squares

- Measurement
- Shear
- Historical wind resource
- Future wind variability
- Wind flow modeling
- Total uncertainty

Single Mast

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But it's *not* safe to assume that when combining uncertainties from multiple masts.

- MCP errors are likely to be similar for all masts
- The future wind climate will vary in a similar way across the site
- Shear profiles are often similar across a site – so shear errors *may* be similar
- If the towers are placed in similar locations (e.g., along a ridgeline), wind flow modeling errors *may* be similar

So be careful how you apply the sum-of-squares rule!

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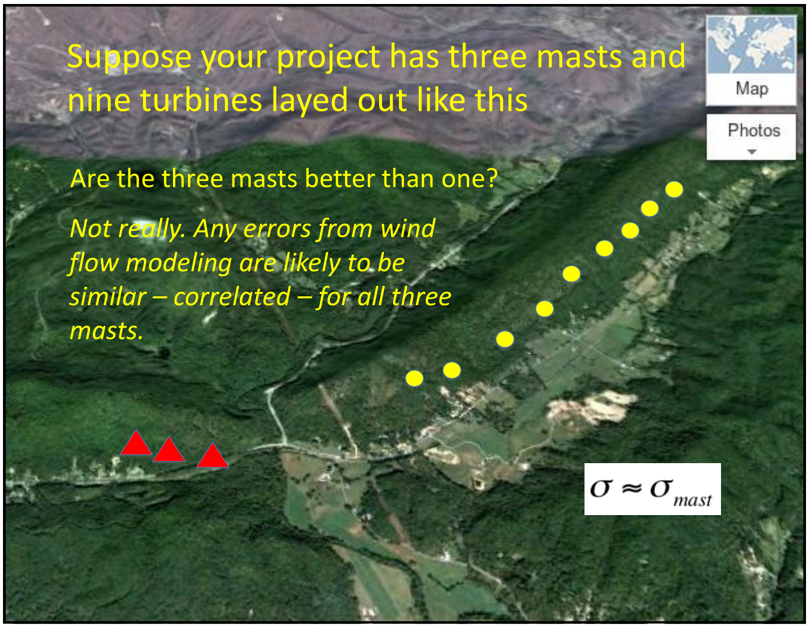
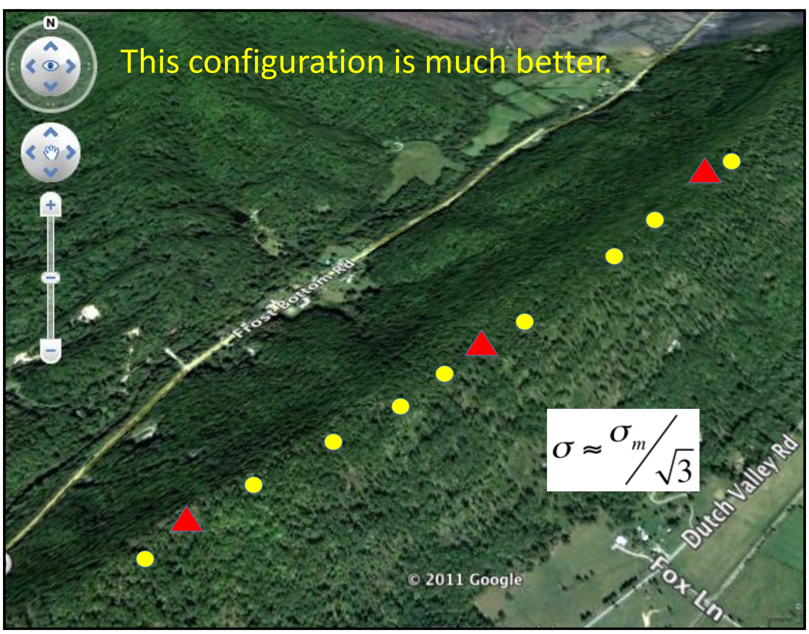
12/14/2011


Suppose your project has three masts and nine turbines layed out like this
Map
Photos
Are the three masts better than one?
Not really. Any errors from wind flow modeling are likely to be similar – correlated – for all three masts.
$\sigma \approx \sigma_{mast}$


N
This configuration is much better.
Frost Bottom Rd
$\sigma \approx \sigma_m / \sqrt{3}$
Dutch Valley Rd
Fox Ln
© 2011 Google

This is a good time to say something about *bias*

- Bias is a systematic error caused by a flawed instrument, model, or experiment design
- In many applications it's a bigger problem than the "official" uncertainty
- It's not hard to find examples of bias in the wind industry...

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...such as

- Anemometer mounting issues
- Tower siting issues
- Availability issues
- Wind flow modeling issues
- Non-ideal turbine performance conditions
- And others

All leading to...

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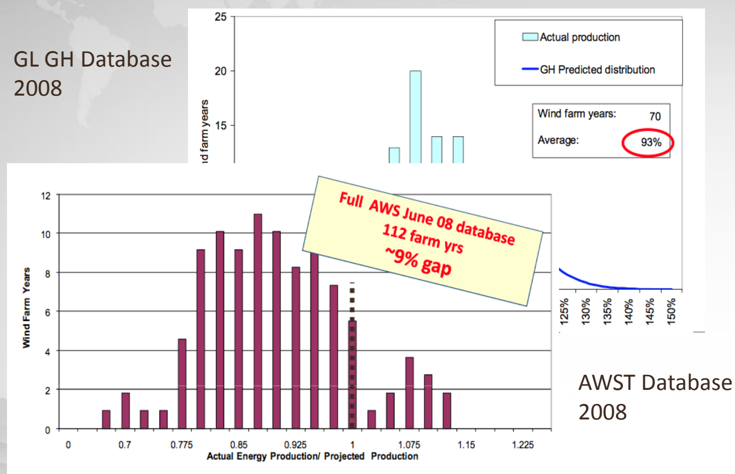
Predicted v. Actual Plant Output (pre-2008)

GL GH Database 2008



AWST Database 2008

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The specific causes of bias will be discussed throughout this workshop. But there are *underlying* causes that deserve attention:

- *Optimism:* You want your project to succeed
- *Selection bias:* Projects with more optimistic forecasts tend to be chosen over others
- *Incomplete information:* Factors you inadvertently ignore are more likely to hurt than help your project's energy production

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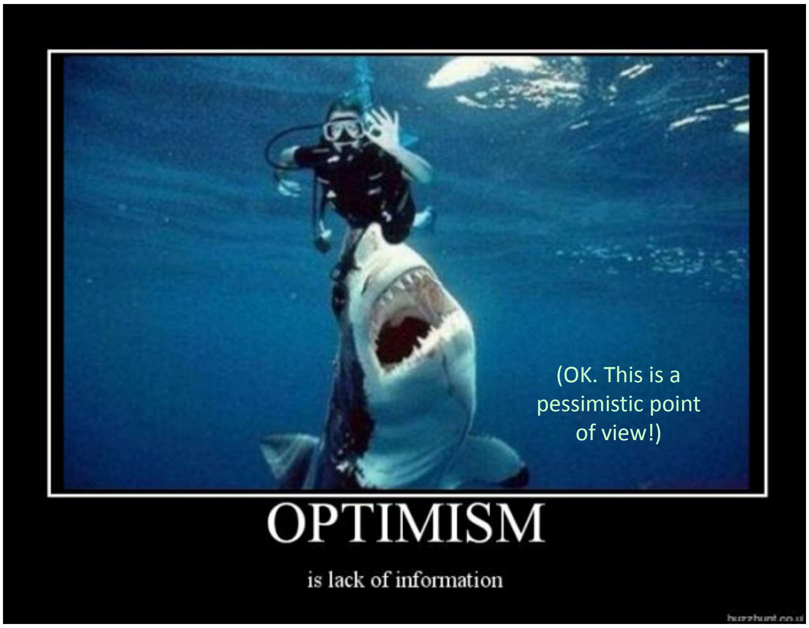

Finally, a word about risk and risk management…

- What's the difference between risk and uncertainty?
  - Risk is the impact of uncertainty on something you value, e.g., project success, profits
- How can risk be managed?
  - By understanding and minimizing, if possible, those sources of uncertainty that pose the greatest risk
- Some uncertainties – like climate variability – can't be reduced no matter how hard you try
  - But most can

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The main goal of wind resource assessment is to minimize project risk within the budget and time constraints of the development process.

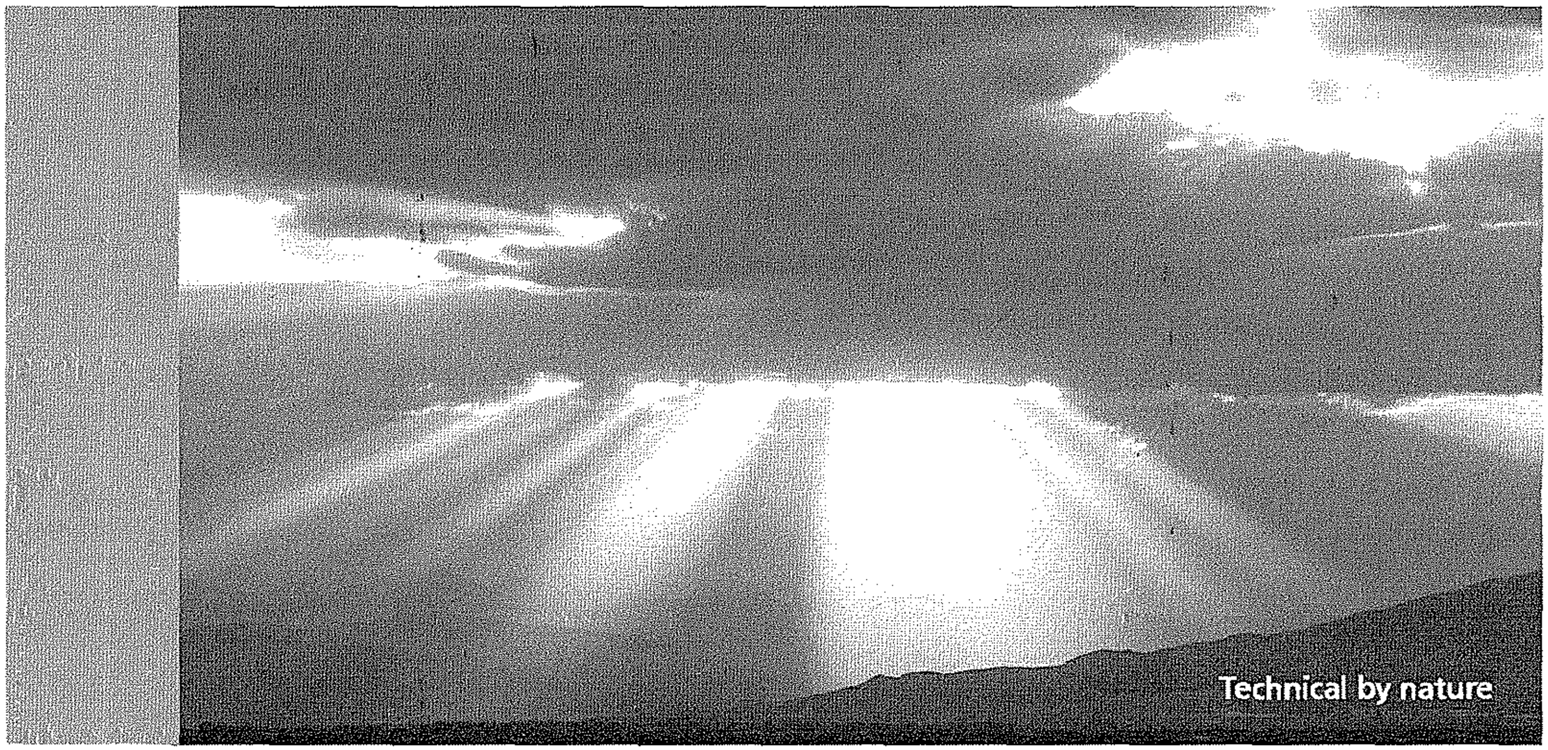
You can only do this if you first understand and quantify the uncertainty.

Renewable energy consultants

GL Garrad Hassan

Actual vs. Predicted performance – Validating pre construction energy estimates

September 2012



www.gl-garradhassan.com

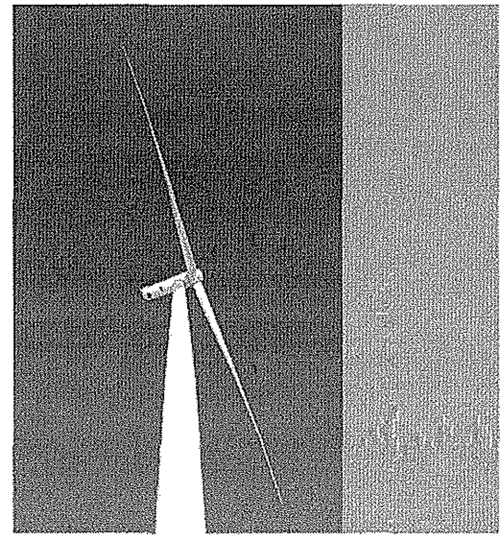
Summary

This presentation provides an update to our 2010 study examining the performance of GL Garrad Hassan (GL GH) predictions against actual wind farm production. In our 2010 validation study, we discussed the history and evolution of GL GH wind assessments and focused on the methodology improvements we have made over time. We made a commitment to continue to validate our assessment methodology and improve the quality and accuracy of our methods. With production data from 125 wind farms totaling 14,000 MW and 382 wind farm years in North America, this current presentation discusses the updates since our 2010 study and reiterates that the GL GH wind assessment methodology is accurate and robust.

GL GH has performed long-term energy production assessments for over 170,000 MW of proposed wind farms internationally and 80,000 MW in North America. In order to assess the accuracy of these predictions, GL GH maintains an internal database which allows the actual wind farm production to be compared with pre-construction estimates. Using the information within this database, GL GH has investigated how these constructed wind farms have performed in relation to the original GL GH pre-construction predictions.

In this presentation, we focus on what has changed since our 2010 validation study. We also examine how projects constructed in the last few years compare to GL GH predictions, in order to show how the accuracy of GL GH assessments has improved. Finally, with the most recent methodology refinements made in 2011, we conclude that GL GH predictions using current methods show no bias in comparison to the actual performance of North American wind farms.

Overview



- History & Evolution
- Current Status of GL GH Assessment Validation
- Conclusions

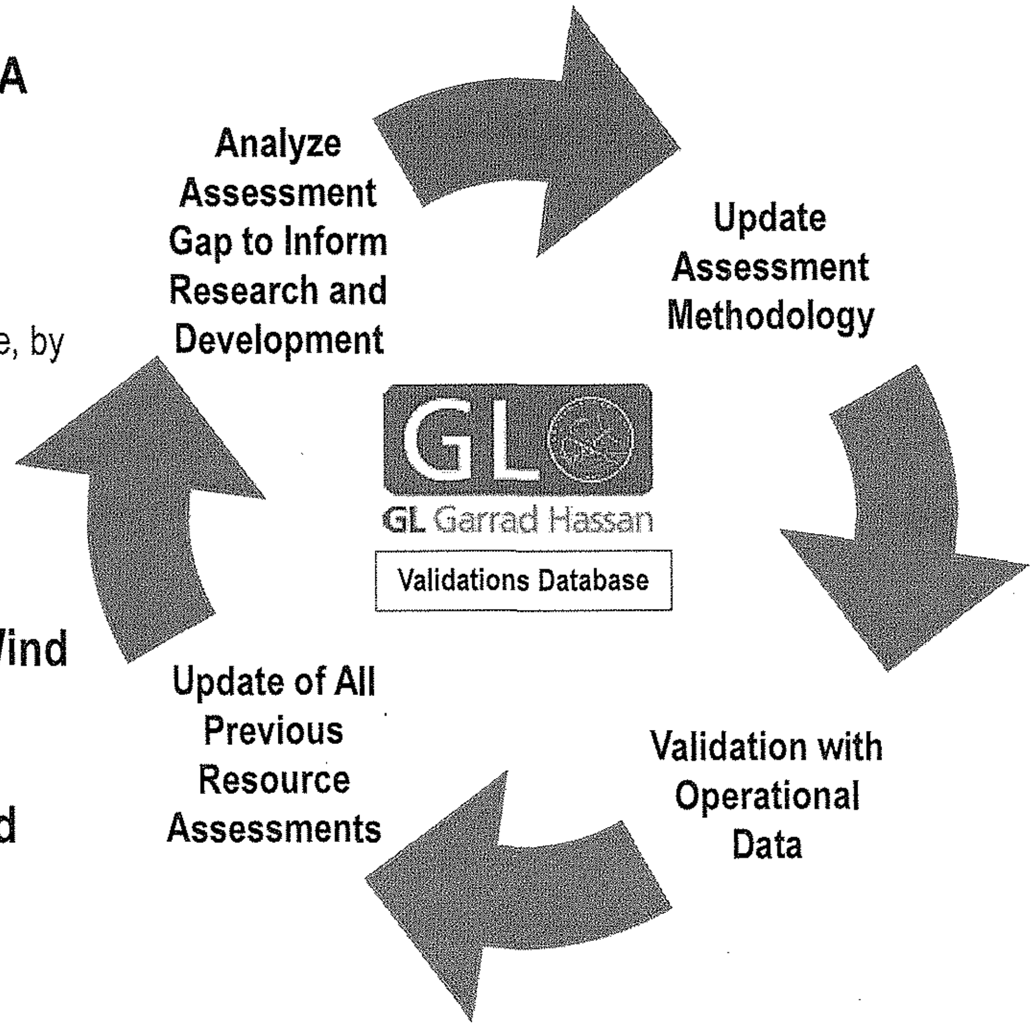
History and Evolution

GL GH Experience

- **Conducted Wind Assessments of over 170,000 MW Globally**
  - Over 80,000 MW assessed in the US and Canada
  - Of these 80,000 MW, over 34,000 MW are now operating in the US and Canada
- **Performed Technical Due Diligence on over 40,000 MW Globally**
  - Over 27,000 MW assessed in the US and Canada
  - Expert insight into the financing and construction process
- **Performed Operational Energy Assessments on over 30,000 MW Globally**
  - Over 12,000 MW assessed in the US and Canada
  - Increased resolution on individual project performance characteristics
  - Improved understanding of differences between pre-construction wind assessment and operational performance

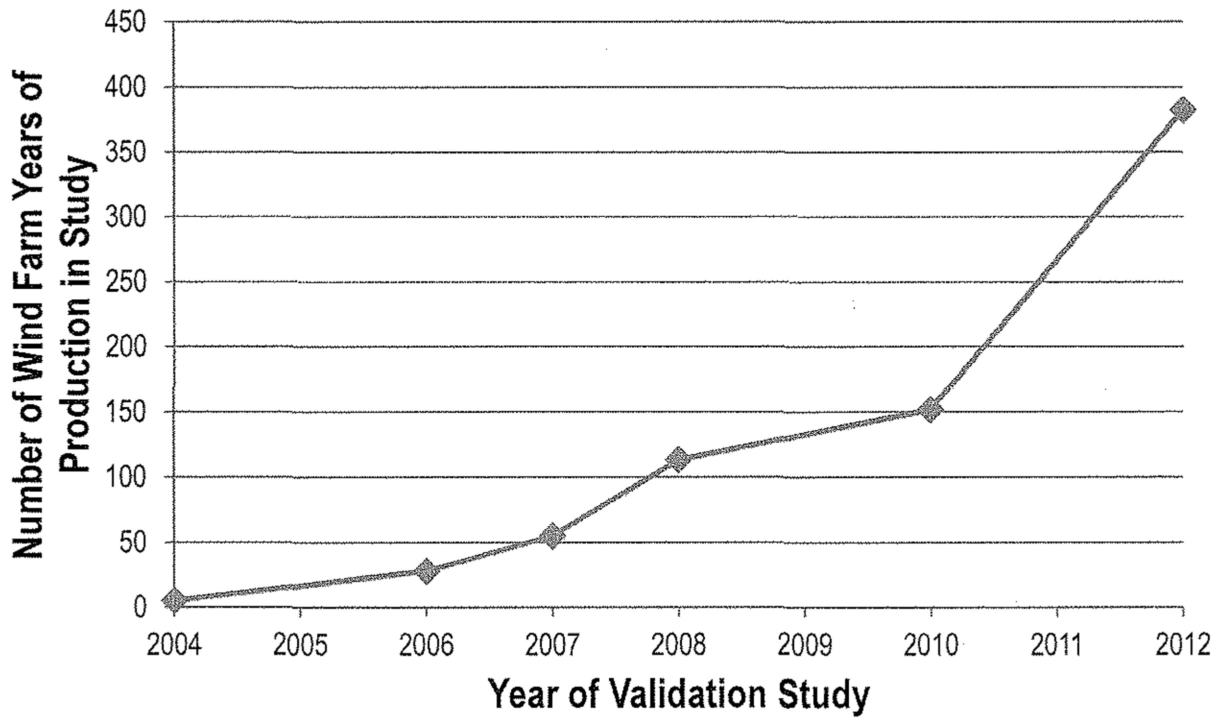
Using Feedback to Improve Methods

- **Perform Detailed Forensics on SCADA Data from Operating Projects**
  - Evaluate availability
    - Determine cause of downtime
    - Categorize availability losses
    - Identify trends (by technology, by time, by region, etc.)
  - Evaluate turbine power performance
  - Examine wind flow modeling and wake loss calculations
- **GL GH Has Conducted Analyses of Wind Farm SCADA Data on Over 30,000 MW**
- **This Feedback is Used to Validate and Refine Methods**

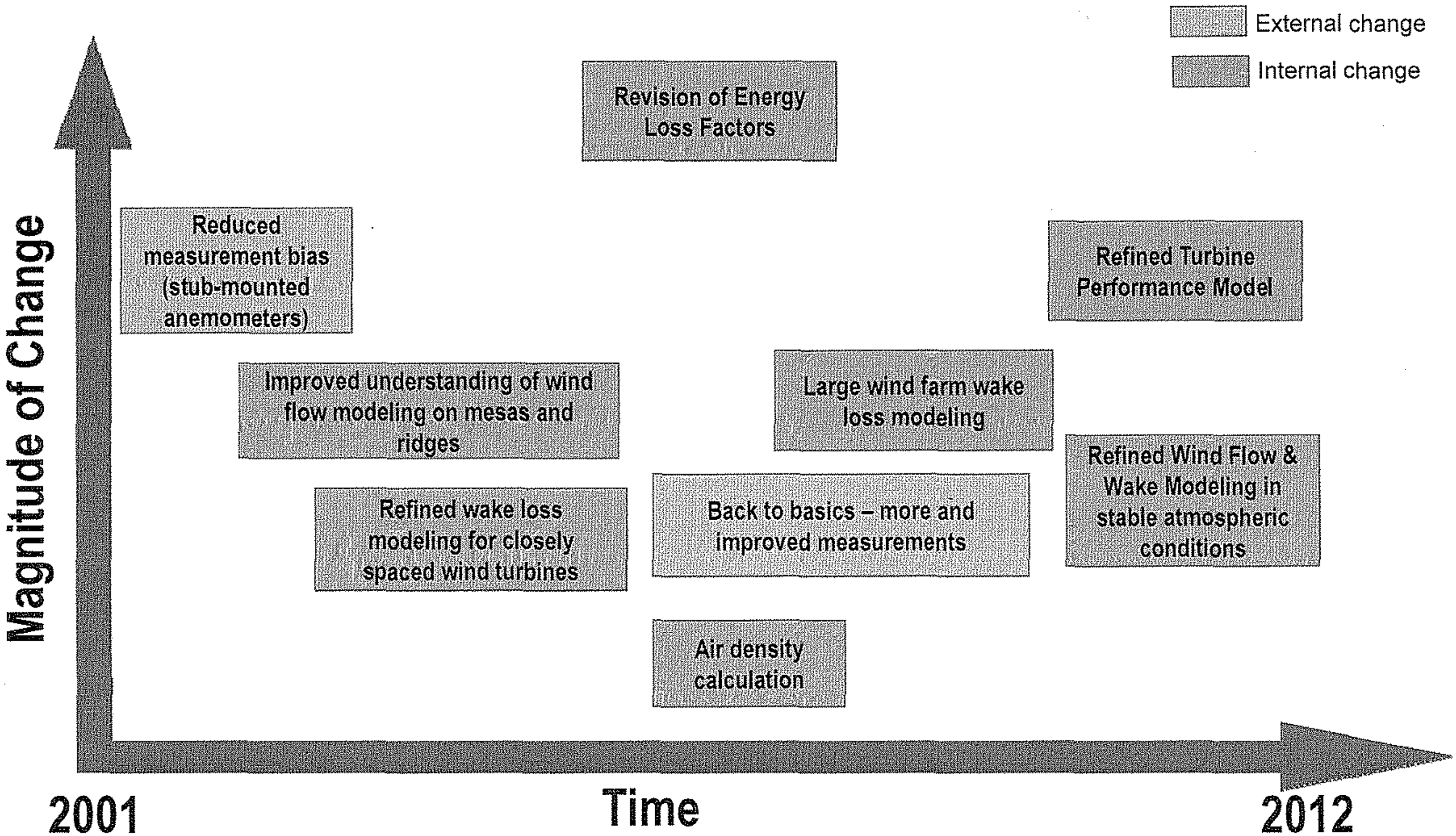


GL GH has a long history of validating production assessments

2004: The first validation presentation at AWEA WINDPOWER 2004 in Chicago
2006: AWEA Finance Workshop in New York
2007: AWEA Wind Resource Assessment Workshop in Portland
2008: AWEA WINDPOWER in Houston
2010: S&P Project & Infrastructure Finance Conference in New York (and others)
2012: AWEA Wind Resource Assessment Workshop in Pittsburgh



Evolution of GL GH Energy Production Assessments



Current Status of GL GH Assessment Validation

Validation Database

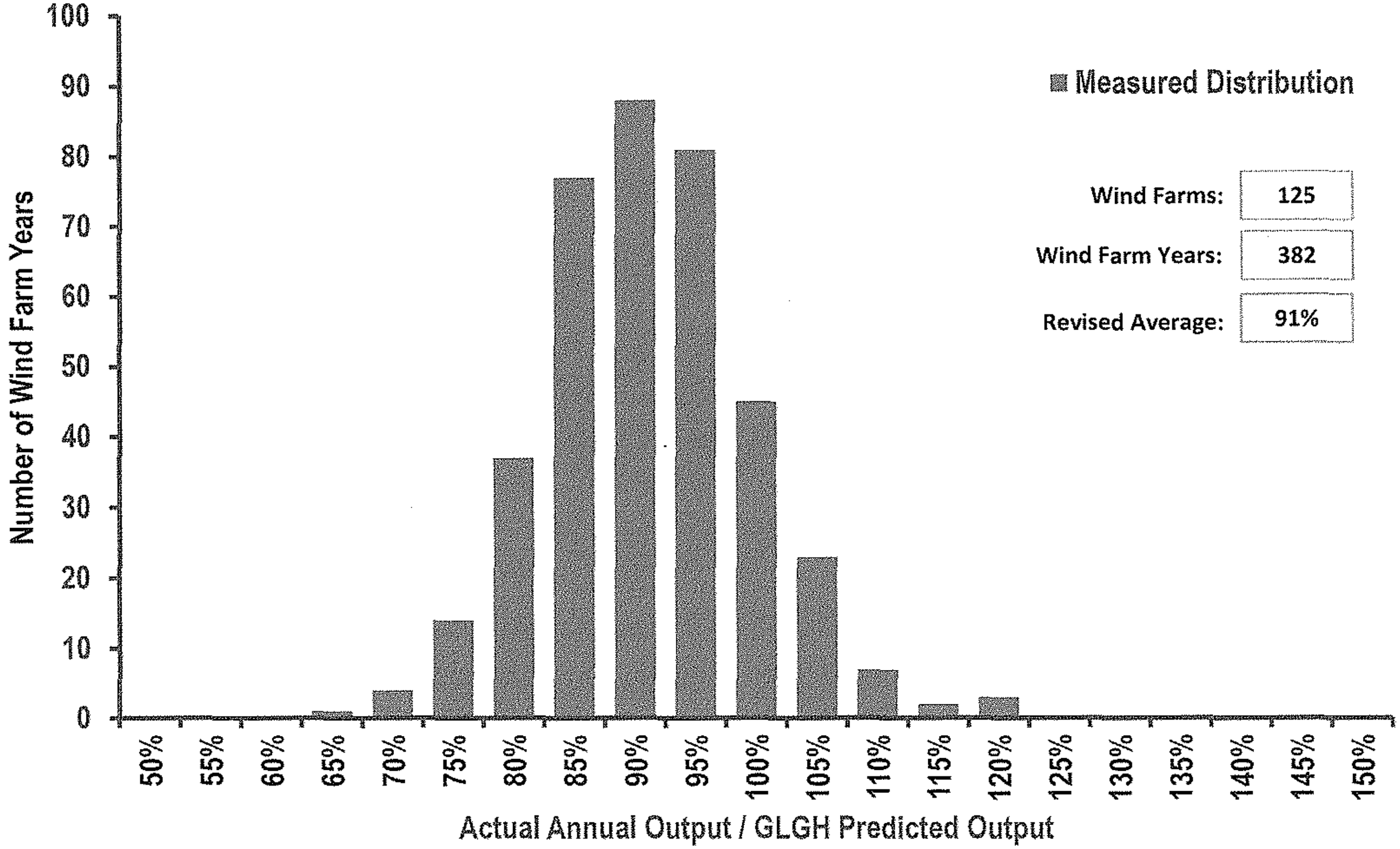
GL GH Wind Farm Production Database

Attributes	2012 Database
Number of Wind Farms	125
Number of Wind Farm Years	382
Total MWs	14,000
Date of Most Recent Data Addition	2012

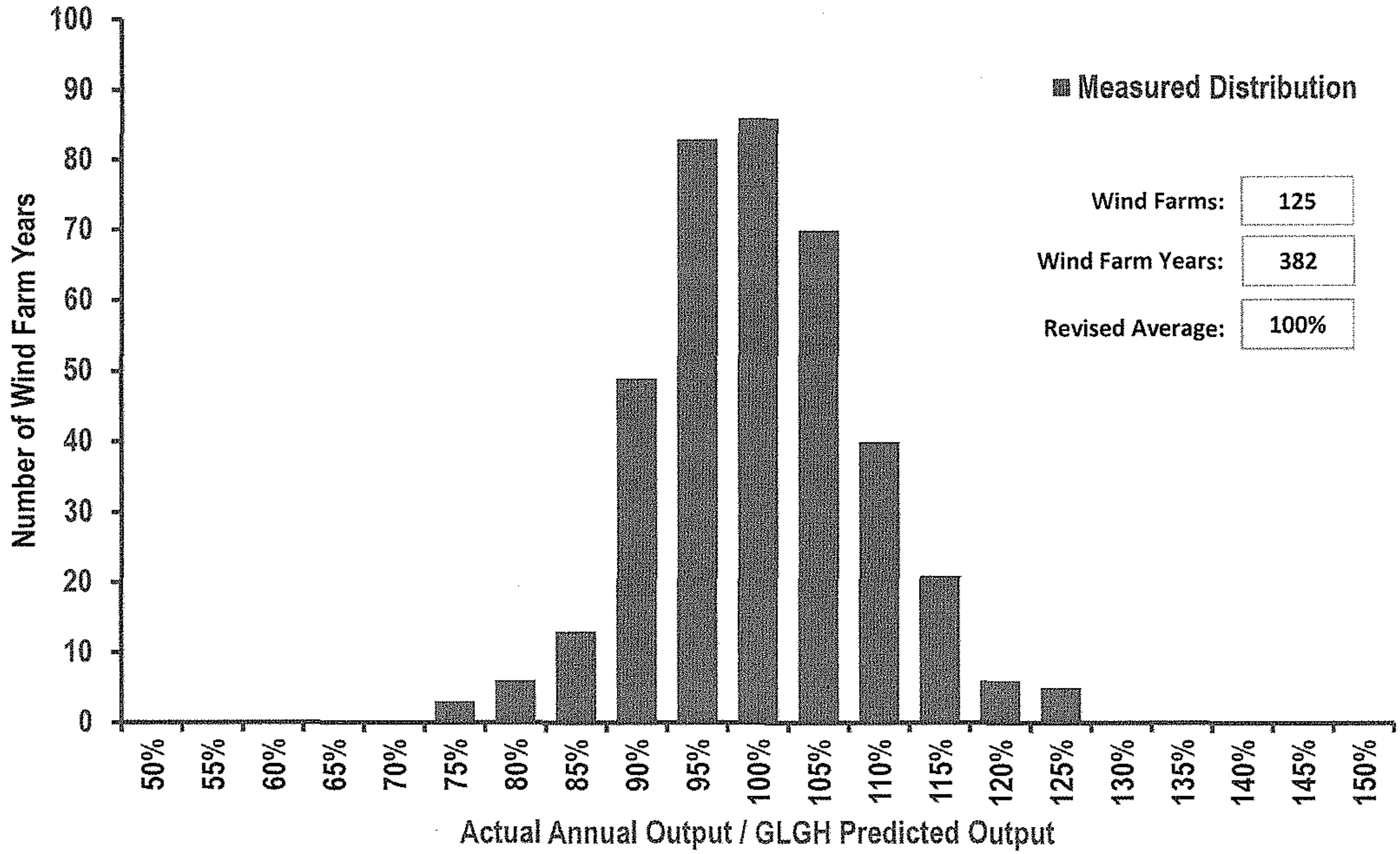
Database Compares Actual Production to GL GH Predictions

- Compare energy output in each year of operation of a wind farm to GL GH P50 prediction
- Compare distribution of all years of production of all wind farms to theoretical distribution accounting for uncertainty
- Actual production is unadjusted, except where **grid curtailment** is present and can be estimated.

Comparison of Actual Output to GL GH P50: Raw observations



Comparison of Actual Output to GL GH P50: Results Using Current Methods



Have GL GH Wind Assessments Improved Over Time?

- **What evidence exists to show the gap between actual and predicted output is shrinking after methodology refinements are implemented?**

- **Results of validations on projects assessed after the major methodology refinement in 2008:**
  - 36 Wind Farms in the US and Canada totaling over 3500 MW
  - 62 Wind Farm Years of Production
  - **Actual Production is 97.9% of Original P50 Prediction**

Relatively Recent Areas of Improvement

- **Turbine Power Performance**
  - Capturing performance variation with atmospheric stability
  - Accounting for all sub-optimal performance

- **Wake Effects**
  - Incorporating impacts from all external wind farms
  - Modeling wakes during very stable conditions over long distances

- **Wind Flow Modeling**
  - Modeling wind flow variation during stable conditions with CFD

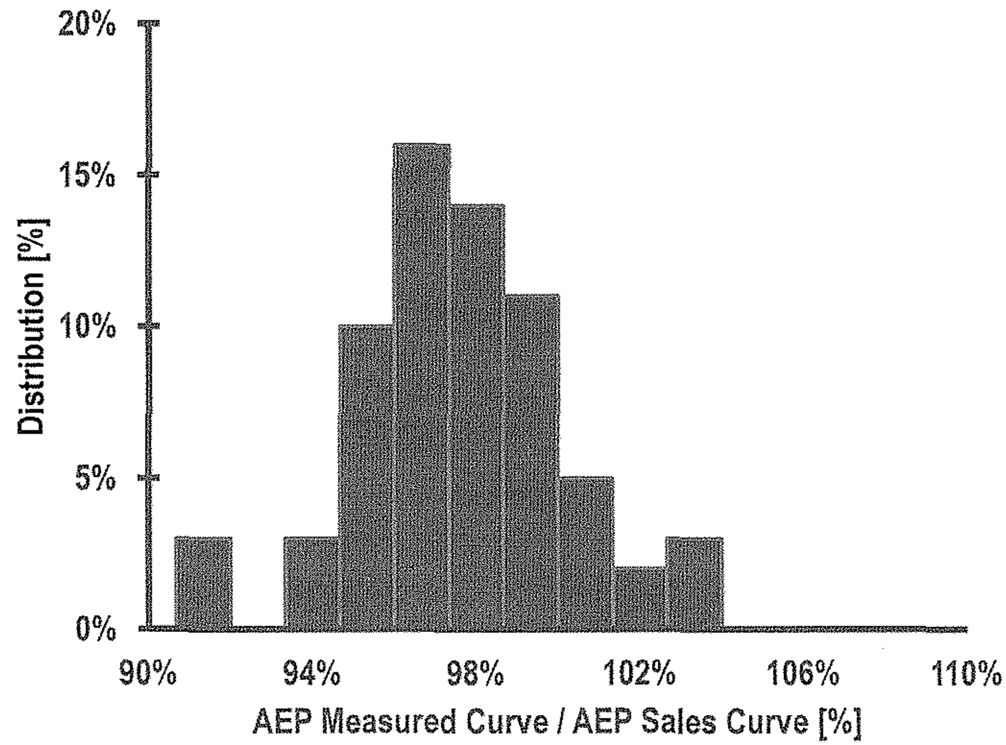
Refinements since 2010 Study: Turbine Power Performance

Review of Turbine Power Performance Tests

- Average measured turbine performance across ~70 performance tests was approximately 97.5%

Meteorological Related Performance

- Stable atmospheric conditions
- Shear relaxation above hub-height



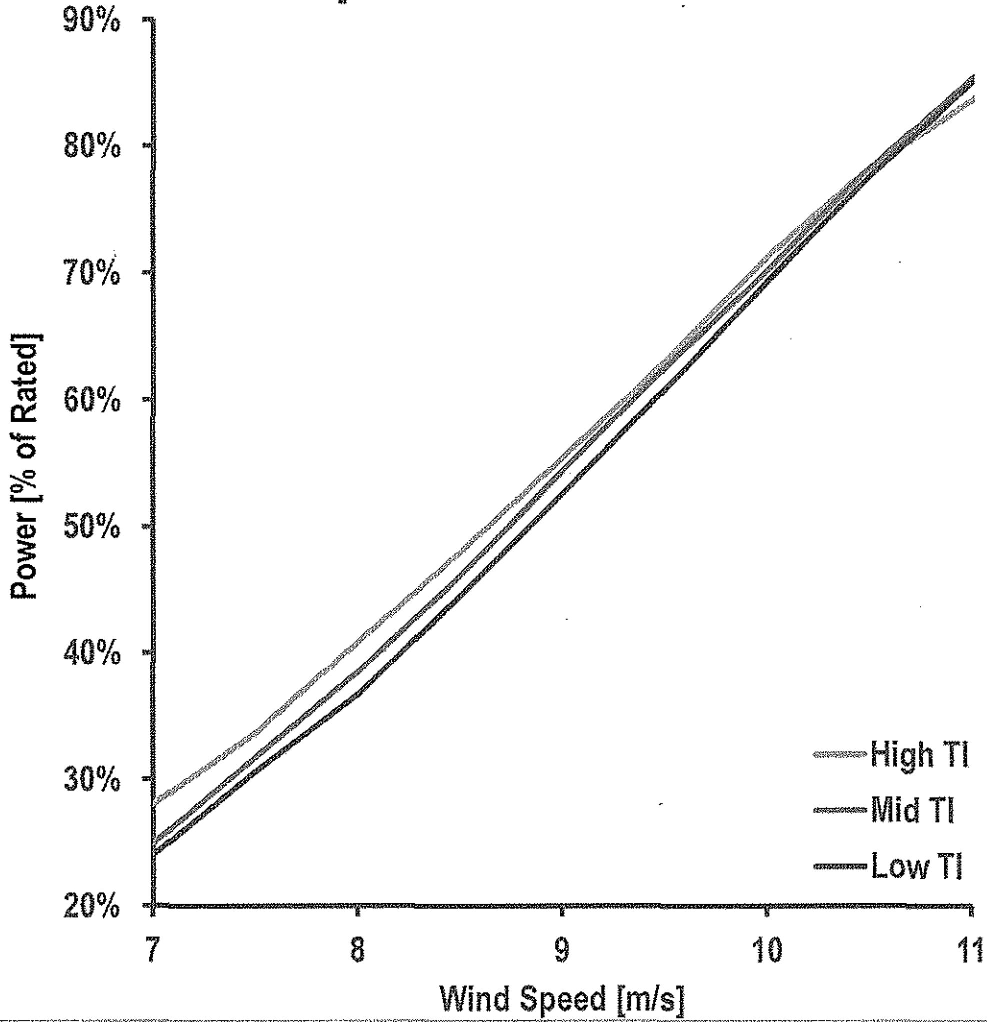
Refinements since 2010 Study: Turbine Power Performance – example Power Curve

Case	TI Range	Time	AEP*
High	TI>12%	44%	100%
Mid	8%<TI< 12%	33%	98.0%
Low	TI<8%	23%	96.4%

* Normalized to High TI case

Power curve variation observed:

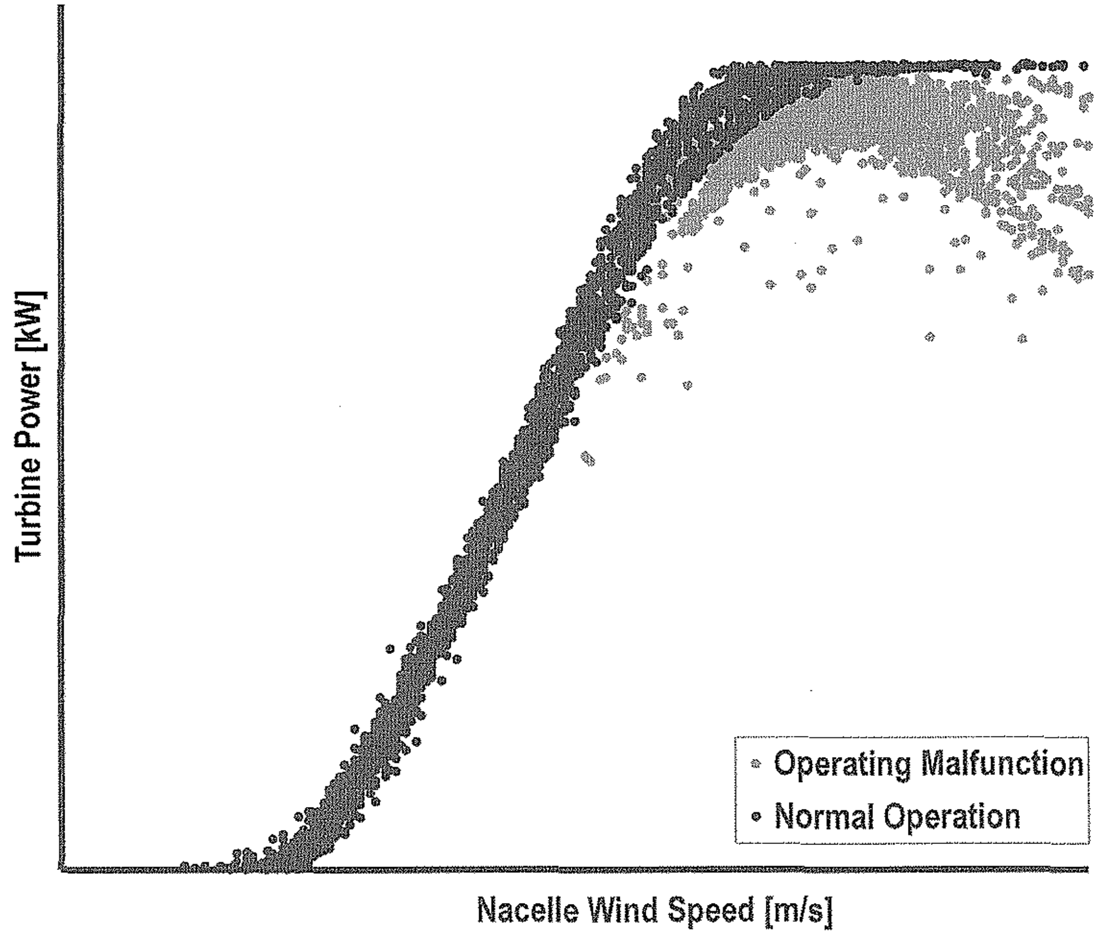
- Significantly lower performance during periods of low turbulence intensity, which corresponds to stable atmospheric conditions



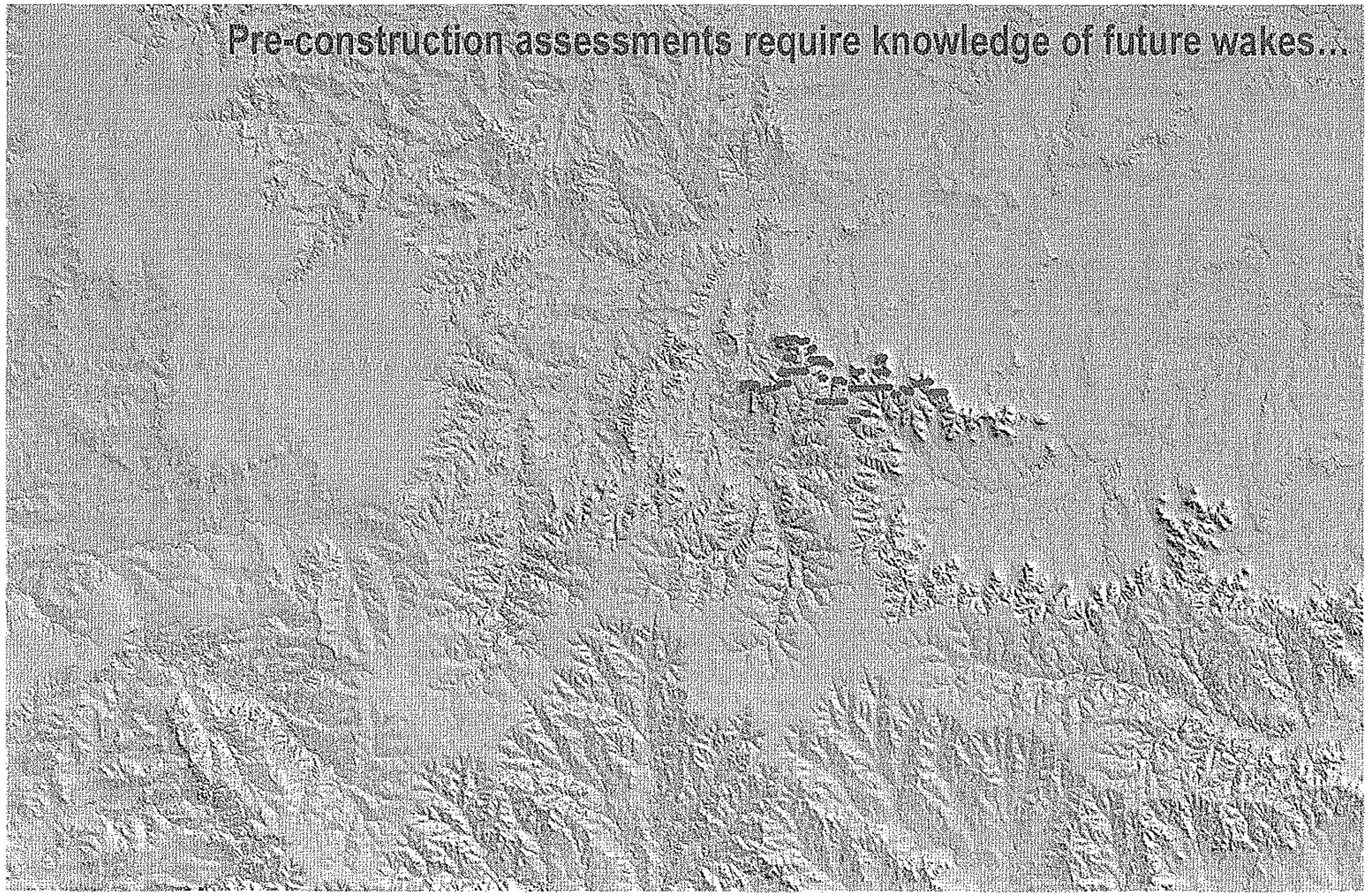
Refinements since 2010 Study: Turbine Power Performance

Sub-optimal Performance

- Turbines can often be operating and "available", but still experiencing underperformance issues
- In general, controllable turbine inefficiencies still account for material energy losses over a project lifetime

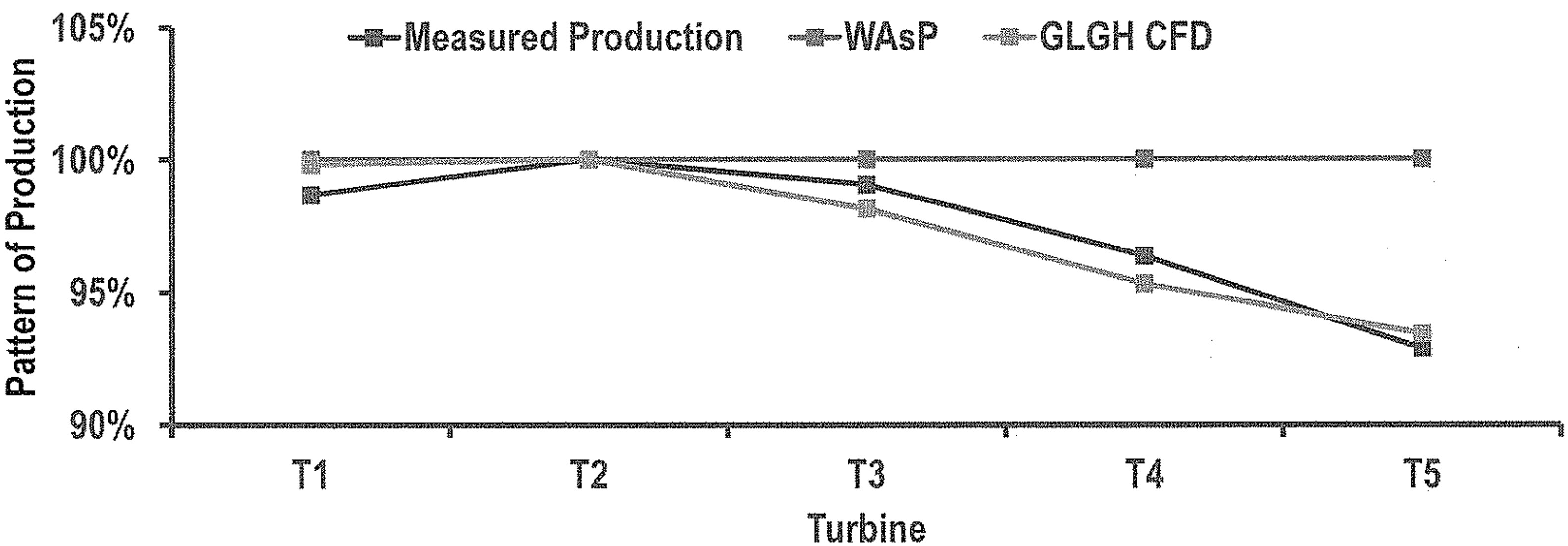


External Wakes – West Texas Build Out (2001)



External Wakes – West Texas Build Out (2009)

Wind Flow Modeling – Capturing stability

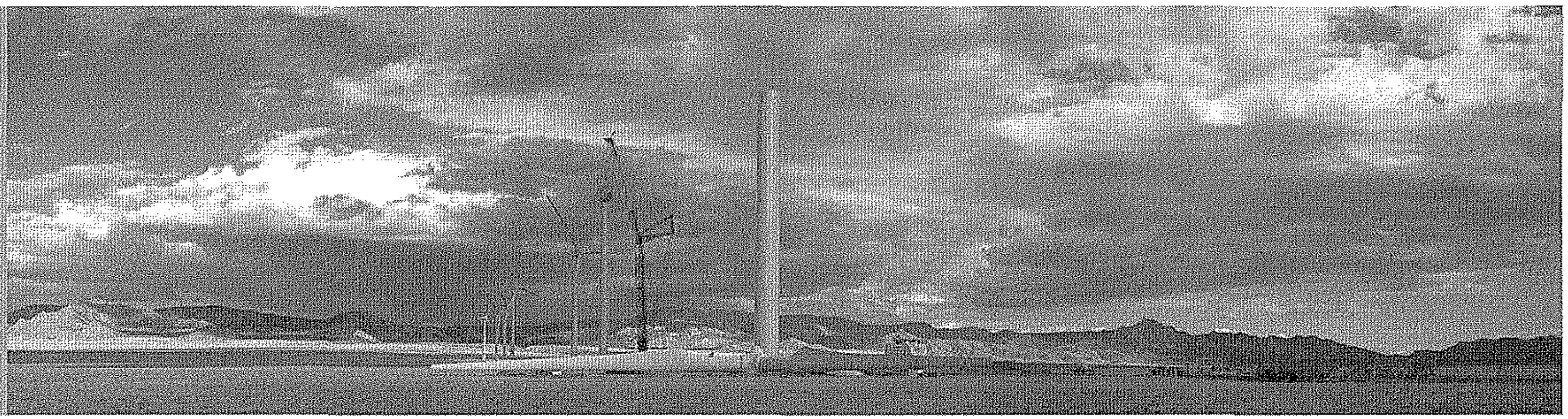


Conclusions

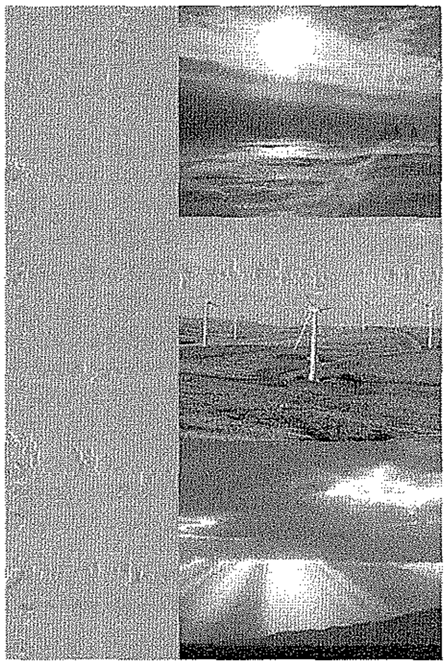
- GL GH Energy Production Validation Database has been updated to include 125 wind farms and 382 wind farm years of production in North America

- Evidence suggests the gap between actual production and GL GH predictions has reduced over time

- GL GH Wind Assessments using current methods exhibit no bias in comparison to actual production



Thank you!



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