**Portland General Electric Company**
*121 SW Salmon Street • Portland, Oregon 97204*
*PortlandGeneral.com*

January 14, 2013

***Email / US Mail***
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Oregon Public Utility Commission
Attention: Filing Center
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**Re: UM 1182 Phase II**
**In the Matter of PORTLAND GENERAL ELECTRIC COMPANY'S REPLY TESTIMONY**

Attention Filing Center:

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

Original and five copies of Reply Testimony of:
- **Darrington Outama, Ty Bettis, Jaisen Mody and Patrick G. Hager (PGE / 200)**
- **Jonathan Jacobs (PGE / 300)**

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

Patrick G. Hager
Manager, Regulatory Affairs

PGH:kr
*encl.*
cc: UM 1182 Service List

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## CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY'S REPLY TESTIMONY (PGE / 200, 300)** 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 14th day of January, 2013.


Patrick G. Hager
Manager, Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0702
Portland, OR 97204
503-464-7580 Telephone
503-464-7651 Fax
patrick.hager@pgn.com

**SERVICE LIST –**
**OPUC DOCKET # UM 1182**

| | |
|---|---|
| Janet L. Prewitt, Assistant AG<br>DEPARTMENT OF JUSTICE<br>janet.prewitt@doj.state.or.us<br>(*Waived Paper Service) | Matt Hale, Manager – Energy Technology<br>OREGON DEPARTMENT OF ENERGY<br>matt.hale@state.or.us<br>(*Waived Paper Service) |
| Vijay A. Satyal, Senior Policy Analyst<br>OREGON DEPARTMENT OF ENERGY<br>vijay.a.satyal@state.or.us<br>(*Waived Paper Service) | Ann L. Fisher, Attorney at Law<br>AF LEGAL & CONSULTING SERVICES<br>energlaw@aol.com<br>(*Waived Paper Service) |
| David J. Meyer, Vice President & General Counsel<br>AVISTA CORPORATION<br>david.meyer@avistacorp.com<br>(*Waived Paper Service) | Patrick Ehrbar, Mgr Rates & Tariffs<br>AVISTA CORPORATION<br>pat.ehrbar@avistacorp.com<br>(*Waived Paper Service) |
| Michael Parvinen, Mgr Regulatory Affairs<br>CASCADE NATURAL GAS<br>michael.parvinen@cngc.com<br>(*Waived Paper Service) | Dennis Haider, Executive VP<br>CASCADE NATURAL GAS<br>Dennis.haider@mdu.com<br>(*Waived Paper Service) |
| Gordon Feighner, Utility Analyst<br>CITIZENS' UTILITY BOARD<br>gordon@oregoncub.org<br>(*Waived Paper Service) | Bob Jenks, Executive Director<br>CITIZENS' UTILITY BOARD<br>bob@oregoncub.org<br>(*Waived Paper Service) |
| G. Catriona McCracken, Staff Attorney<br>CITIZENS' UTILITY BOARD<br>catriona@oregoncub.org<br>(*Waived Paper Service) | Irion A. Sanger<br>DAVISON VAN CLEVE<br>ias@dvclaw.com<br>(*Waived Paper Service) |
| S. Bradley Van Cleve<br>DAVISON VAN CLEVE<br>mail@dvclaw.com; bvc@dvclaw.com<br>(*Waived Paper Service) | John W. Stephens<br>ESLER STEPHENS & BUCKLEY<br>stephens@eslerstephens.com<br>mec@eslerstephens.com<br>(*Waived Paper Service) |
| Christa Bearry<br>IDAHO POWER COMPANY<br>cbearry@idahopower.com<br>(*Waived Paper Service) | Lisa Nordstrom<br>IDAHO POWER COMPANY<br>lnordstrom@idahopower.com<br>(*Waived Paper Service) |
| Ann L. Fisher, Attorney at Law<br>LEGAL & CONSULTING SERVICES<br>ann@annfisherlaw.com | Lisa F. Rackner, Attorney<br>McDOWELL RACKNER & GIBSON, PC<br>dockets@mcd-law.com<br>(*Waived Paper Service) |
| David E. Hamilton<br>NORRIS & STEVENS<br>davidh@norrstev.com<br>(*Waived Paper Service) | Alex Miller, Director – Regulatory Affairs<br>NORTHWEST NATURAL GAS COMPANY<br>Alex.miller@nwnatural.com<br>(*Waived Paper Service) |

| | |
|---|---|
| Wendy Gerlitz<br>NORTHWEST ENERGY COALITION<br>wendy@nwenergy.org<br>(*Waived Paper Service) | Robert D. Kahn<br>NW INDEPENDENT POWER PRODUCERS<br>Rkahn@nippc.org<br>rkahn@rdkco.com<br>(*Waived Paper Service) |
| Mary Wiencke<br>PACIFICORP<br>mary.wiencke@pacificorp.com<br>(*Waived Paper Service) | Natalie L. Hocken<br>PACIFICORP<br>natalie.hocken@pacificorp.com<br>(*Waived Paper Service) |
| Oregon Dockets<br>PACIFICORP<br>oregondockets@pacificorp.com<br>(*Waived Paper Service) | Maury Galbraith<br>PUBLIC UTILITY COMMISSION OF OREGON<br>Maury.galbraith@state.or.us<br>(*Waived Paper Service) |
| Michael T. Weirich, Assistant AG<br>DEPARTMENT OF JUSTICE<br>Business Activities Section<br>michael.weirich@state.or.us<br>(*Waived Paper Service) | Megan Walseth Decker, Senior Staff Counsel<br>RENEWABLE NORTHWEST PROJECT<br>megan@rnp.org<br>(*Waived Paper Service) |
| Gregory M. Adams<br>RICHARDSON & O'LEARY<br>greg@richardsonandoleary.com<br>(*Waived Paper Service) | William A. Monsen<br>MRW & ASSOCIATES, LLC<br>wam@mrwassoc.com<br>(*Waived Paper Service) |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1182 Phase II

**PORTLAND GENERAL ELECTRIC COMPANY**

Reply Testimony and Exhibits of

***Darrington Outama***
***Ty Bettis***
***Jaisen Mody***
***Patrick G. Hager***

Portland General Electric

**January 14, 2013**

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# I. Introduction

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

A. My name is Darrington Outama. I am the Manager of 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 PGE Exhibit 100.

**Q. Please describe how your reply testimony is organized?**

A. Section II responds to NIPPC's direct testimony, with particular attention to problems with NIPPC's adder approach (Section II.A), heat rate degradation (Section II.B), cost under-runs and over-runs (Section II.C), capacity factors for wind resources (Section II.D), and counterparty risk (Section II.E). Section III responds to Staff's direct testimony.

## II. Response to NIPPC's Direct Testimony

### A. Problems with the "Adder" Approach

**Q. From your reading of NIPPC's testimony, what problem is the adder approach intended to address?**

A. Our understanding is that adders are intended to correct for alleged flaws in the scoring of benchmark bids. In this case, the alleged flaws are purported to favor the benchmark bids by either understating the cost or overstating the performance for a benchmark bid.

**Q. If the work of the Independent Evaluator (IE) results in accurately scored bids, would bid adders improve the evaluation process?**

A. No. The evaluation criteria used to score bids are developed to account for the benefits, costs, and risks associated with each proposal. If a robust bid evaluation methodology is utilized, there is no remaining need for adders. Improving the evaluation method and process directly would be a superior approach to the application of rigid and probably inaccurate bid adders.

**Q. In practice, will the adder approach as suggested by NIPPC be effective in detecting and correcting deficiencies in the scoring methodology?**

A. No, the bid adders NIPPC proposes will likely introduce systematic flaws in the scoring methodology that could lead to the selection of bids that reflect higher cost alternatives for our customers. To obtain adders, NIPPC relies on historical data to establish both the existence and magnitude of the alleged bias. The averages that NIPPC computes are statistical estimates and are, therefore, subject to sampling errors. However, NIPPC provides no measures of the accuracy (standard errors) of their estimates. Without measures of accuracy, we cannot conclude with any confidence that bias even exists, much less applies in the scoring of any particular benchmark resource or competitive bid. This deficiency applies to each of the proposed adders NIPPC calculates for heat rate degradation, construction cost over-runs, and wind capacity factor.

**Q. What are the problems with the data that NIPPC uses to calculate their adders?**

A. We discuss specific data problems in more detail in Section II.B, II.C and II.D as does Dr. Jonathan Jacobs (PGE Exhibit 300), but in general NIPPC's estimated adders suffer from one or more of the following data deficiencies:

- Small sample size (construction cost overruns);
- Non-representative samples (heat rate degradation, construction cost overruns, wind capacity factors);
- Use of an irrelevant historical period (heat rate degradation, construction cost overruns, wind capacity factors).

**Q. Are the plant observations that NIPPC uses in their empirical work representative of PGE's experience or practice?**

A. No. Dr. Jacobs (PGE Exhibit 300) demonstrates that the data sets that NIPPC witness Monsen relied upon are flawed and do not yield appropriate adjustments to the methodology for scoring competitive bids. For wind capacity factors, we show in Section II.D below that NIPPC's analysis uses data that are neither appropriate nor representative of wind forecasting accuracy on a going forward basis.

**Q. Is there an inherent problem in NIPPC's use of historical data to adjust the scoring of benchmark and competitive bids?**

A. Yes. To be useful in the evaluation of bids, data must reflect current (and expected) technology, market conditions, and regulatory practice. A historical data series long enough to produce a "reasonable" sample size is likely to extend back to a time period that is not relevant if the forecasting methodology is changing.

**Q. Is it possible that the use of adders could provide an incentive for IPP's to increase their PPA bids and thereby make the RFP process less competitive?**

A. Yes. In developing generation projects, IPPs and utilities essentially face the same set of costs, challenges, and opportunities. If IPPs recognize that they are competing against a benchmark resource that is subject to artificial cost adders, they would have an opportunity and incentive to increase their bid price because the benchmark resource will be handicapped by the adder and therefore less competitive. A less competitive bidding process is not in the best interest of our customers.

**Q. What assumptions does NIPPC use to justify the use of an adder?**

A. NIPPC's proposal is based on the presumption that a utility can understate its costs and later "game" the rate-making process to recover its true costs. Such a presumption incorrectly discounts the rigor and scrutiny of the ratemaking process in Oregon.

**Q. Are there other reasons for rejecting an adder approach?**

A. Yes, the adder approach would unduly complicate the scoring process. The role of the Independent Evaluator (IE) is to ensure that bids are assessed accurately using a uniform set of criteria. The adders have unknown accuracy and unknown variation, making the assessment of the relative merits of alternative bids and resources more difficult, not less.

## B. Heat Rate Degradation

**Q. Dr. Jacobs (PGE Exhibit 300) has concerns regarding NIPPC's study on heat rate degradation. Can you briefly summarize his concerns?**

A. Yes. Dr. Jacobs correctly points out that in order to determine whether or not a heat rate degradation bias exists for benchmark bids "the analysis would have to use appropriate data, correct as necessary for plant commitment and dispatch, and have a baseline similar to the benchmark bids themselves" (PGE Exhibit 300, page 10 at 3-5). Dr. Jacobs goes on to add "[t]he baseline for an analysis like NIPPC's if the goal were to determine whether the utility forecasts were biased, would be a hypothetical forecast constructed for each plant using the utilities' methods and contemporary manufacturer information" (PGE Exhibit 300, page 11 at 21-23).

**Q. What is PGE's position on heat rate degradation?**

A. We believe that the appropriate heat rate to utilize in scoring all bids, not just benchmark bids, is a long-run degraded heat rate based on information provided by the turbine manufacturers. As work papers stated in our direct testimony, PGE's benchmark bids already incorporate the long-run degraded heat rate. If a bid includes a heat rate that is lower (better) than the long-run degraded heat rate, then the bid's score should be adjusted to reflect a long-run degraded heat rate.

### C. Cost Under-Runs and Over-Runs

**Q. Do you agree with Dr. Jacob's observation that the data that Monsen used in his analysis does not satisfy the conditions needed to conduct an analysis for potential bias?**

A. Yes. We also note that the PGE benchmark resources that were previously selected through competitive bidding processes have been completed at less than expected cost.

### D. Capacity Factors for Wind Resources

**Q. NIPPC advocates using an adder approach to correct wind capacity forecasting errors. Is this approach valid?**

A. No. NIPPC derives its adder using historical wind data, which is based on forecasting models that were developed when wind power was in its infancy in the United States. At that time, extensive wind data were not available and models were thus developed using small samples, which were the only data available. Over time as more data became available, inefficiencies in wind data and modeling techniques were observed and corrected for to produce more accurate and robust forecasts. Any reasonable forecaster would consider their prior inaccuracies, incorporate additional data, and revise forecasting models and methods to improve their forecasts over time.

In short, with time and greater experience, forecasting techniques and results improved. Accordingly, using past forecasting errors to predict future forecasting accuracy is a flawed approach because it assumes that forecasters will not learn and improve over time which Monsen implicitly assumed. He provided no evidence to support this faulty assumption.

**Q. Is there a need for a capacity factor adder for wind plants?**

A. No. Monsen's approach is to reduce the expected capacity factor for benchmark wind plants. The logic for this reduction is based on research he performed on twelve wind plants owned and operated by PacifiCorp. He claims that PacifiCorp's plants have underperformed their expected capacity factors by a weighted average of 11.7%.

The Monsen study compared only a few years of operating data to the projected capacity factor for the entire life of a project. Relying on a data set with a very limited number of wind years and plants is not likely to lead to a robust and unbiased estimate of capacity factors. Calculating and utilizing an adder based on a very limited amount of data, especially for a resource where the fuel availability (wind) is recognized to vary considerably from year to year, is likely to lead to an estimate with a high probability of departing materially from the true value.

**Q. You mentioned that prior years' wind capacity factor forecasts are not a reliable indicator of future forecasting accuracy. Would you please explain?**

A. Certainly. The wind industry in the U.S. is still relatively immature. Original plant assessments that were being developed in the early 2000's for plants coming on-line in 2006 -- 2008 were using higher assumed plant availability numbers that were derived from European wind plants. European wind plants were used, even with different turbine technology and turbine concentration / dispersal than in the United States, because there was no significant experience in the U.S. However, in the past 5 – 10 years, the U.S. wind industry has made substantial increases in wind plant deployments, gained operating experience, and made significant strides in improving wind capacity factor assessments.

GL Garrad Hassan (GLGH), a leading company in the field of wind generation assessments, has been very transparent regarding their experience over the past ten years. The accuracy of their wind assessments has significantly improved due to major advances in knowledge, experience, and technology. Monsen, however, implicitly assumes, by using predictions derived from historical, obsolete forecasting techniques, that forecasters will not take advantage of these and future improvements to generate more accurate performance forecasts.

Given the increased deployments and operating experience of the U.S. wind fleet, and the advances in forecasting methods and technologies over the past several years, Monsen's suggested approach of reducing the expected capacity factor for benchmark resources is significantly flawed, and if implemented would result in a less accurate bid evaluation process.

**Q. Are there factors that Monsen failed to incorporate in his analysis of PacifiCorp's capacity factor forecasts?**

A. Yes, Monsen's analysis and testimony excluded several factors that undermine his conclusion.

(1) The first two years of over-estimates were calculated based on the performance of a 41.1 MW wind plant in Southeastern Wyoming (Foote Creek) that was put into service in 1999. This plant was PacifiCorp's first wind plant and was developed when wind energy production was in its infancy in the U.S. Logically, this plant should be removed from the data set as not representative.

(2) It appears that Monsen did not appropriately account for seasonality. For example, he includes the addition of the 100.5 MW Leaning Juniper 1 Wind Farm in 2006 even though it did not reach full commercial operations until September 2006. It is common knowledge that wind capacity factors vary by month and season, and that wind farms in the lower Columbia River Gorge region exhibit higher capacity factors in the late spring and summer while the fall and winter months generally exhibit lower wind production. By utilizing 2006 output in the analysis for Leaning Juniper I, the annual capacity factor results were skewed due to the inclusion of a partial year that was

represented by lower production months. He should have removed the 2006 data for Leaning Juniper I.

This same data error applies to several of the data points Monsen relies upon. The Marengo Wind Farm came online in August 2007, and in 2008, PacifiCorp added another 381 MW of wind, with 164 MW of this wind coming online during the summer of 2008 and another 217 MW in December 2008. All of these annual data points should be removed from the analysis.

Given these infirmities and the limited data set used, the results of Monsen's analysis are not reliable and should not be used.

**Q. Mr. Monsen uses data from different plants over different time periods in three different wind regimes (Columbia River Gorge, Southeast Wyoming, and Eastern Wyoming) to derive a single "lifetime" capacity factor adder. Is this a reasonable methodology? (NIPPC Exhibit 100, pg. 30 at 5-9)?**

A. No. As we have already discussed, the data set has significant deficiencies, which will lead to inaccurate and biased estimates.

**Q. What is a minimum reasonable sample size of annual capacity factor overestimates to determine a "lifetime" capacity factor overestimate?**

A. This is difficult to say because the data must incorporate the weather oscillations that drive the wind. The Pacific Decadal oscillation and inter-decadal oscillation (that are often used for forecasting wind) show that climatic patterns can persist for 20-30 years (Pacific Decadal oscillation) or 8-12 years (inter-decadal oscillation). To filter out time series patterns such as these, one generally needs a dataset with a larger sample size than the length of these known periodic signals. Stated differently, conducting an analysis to determine whether capacity factor bias exists by using a few years of actual data for an asset with a life of more than 30 years is unlikely to lead to accurate predictions of future forecasting errors.

**Q. Has a solution been presented to mitigate the risk that a utility could overestimate the projected wind capacity factor for benchmark resources?**

A. Yes. PacifiCorp states that after development of their shortlist, they retain "a qualified and independent third-party technical expert (the Capacity Factor Expert) to assess the expected wind resource capacity factor associated with each alternative on the initial short list, including the cost-based utility ownership benchmark resource" (PAC Exhibit 100, pg. 6 at 16-18).

**Q. Would PGE support this practice in their RFP scoring process?**

A. Yes. In fact, PGE is using an independent wind expert in our current renewable resource RFP to address this risk and to ensure that the capacity factor estimates for all bids, including the benchmark proposal, are independently reviewed.

## E. Counterparty Risk

**Q. NIPPC has provided testimony from Collins regarding counterparty risk (NIPPC Exhibit 200). Did this testimony address the relevant time period?**

A. No. The testimony focused on the period between 1992 and 1997, the years during which Collins worked in the industry. During that period however, credit concerns and risk evaluation methods were less developed in the wholesale electricity industry than is true today.

**Q. How have credit concerns and risk evaluation methods changed since 1997?**

A. After the energy crisis of 2001, and the subsequent bankruptcies of several large energy merchant and independent power producers (e.g., Enron, National Energy Group, NRG, Mirant, Calpine and Dynegy), the financial world became more conservative regarding the "credit worthiness" of a counterparty. This trend has continued as a result of the more recent financial market crisis and subsequent "Great Recession". Today, a counterparty with less than investment-grade credit rating would not be accepted as a trading partner for spot market power sales much less a long-term PPA. This has been the wholesale energy industry standard for several years.

**Q. NIPPC criticizes the credit rating agencies. Are their arguments persuasive? (NIPPC Exhibit 200, pg.8 at 21)**

A. No. PGE agrees that the rating agencies are implementing reforms, but these reforms are not moving in the direction of relaxing credit requirements for project financing and power plant owners. In fact, the reforms are heading the exact opposite direction: rating agencies are looking past the plant owner to external factors in their assessment of risk. For example, Standard & Poor's *Principles of Credit Ratings* (see PGE Exhibit 201) state that "[i]n addition to our assessment of an obligor's stand-alone creditworthiness, Standard & Poor's analysis considers the likelihood and potential amount of external support (or influence) that could enhance (or diminish) the obligor's creditworthiness."

In addition, debt ratings are more stringent now than when NIPPC's witness worked in the industry. Not only do rating agencies rate the debt that is directly on the entity's balance sheet, they impute additional debt depending on the length and contract terms of long-term contracts that the entity has executed.

**Q. NIPPC claims that "no lender makes a commitment to a loan or can obtain a rating for a loan structure when the PPA terms are still being negotiated" (NIPPC Exhibit 200, pg. 4 at 18). Is this relevant?**

A. No. It is the utility that is ultimately responsible for the delivery of reliable power to its customers. Under a typical PPA, a utility would likely have limited recourse against a seller in the event of contract default because the seller's ownership structure is typically a Special Purpose Entity ("SPE"). However, performance risk can be mitigated in part by the seller / SPE obtaining financial assurances from interested parties (such as a bank or parent company) to support the contract, and through negotiated contract rights such as step-in provisions.

**Q. How does PGE assess credit and counterparty performance risk in its RFP evaluation?**

A. In its RFP scoring process, PGE applies the following industry standard approach to assessing credit and counterparty performance risk:

- Sellers must be investment grade in order to participate. As an alternative, they can obtain parental guarantees or a Letter of Credit from a qualified financial institution to alleviate this obligation.
- A seller with better credit rating and financial ratios will score better. This is to recognize that, all else being equal, purchasing from a AAA-rated company is inherently less risky than purchasing from a company with a more limited or poor credit history.

**Q. Do you agree with Collins' statement that "By raising credit quality as a concern, but not proposing any RFP terms that level the playing field for the regulatory**

**compact's relative financial security, utilities can inadvertently drive up the cost of IPP's signaling to IPP creditors how hostile the franchise is to them" (NIPPC Exhibit 100, pg. 8 at 10-13)?**

A. No. In the case of limited liability entities such as SPEs, PGE's RFP does include terms that allow entities to demonstrate their credit worthiness. These mechanisms include providing a credit support provider guarantee and posting collateral. In addition, the ownership and capital structure of the project company associated with a PPA is a business choice by the bidder. Limited liability ownership structures (SPE) are often chosen by project developers in lieu of balance sheet financing in order to protect the rest of the organization from specific project default risk and in some cases lower the amount of equity funding required. However, such structures are inherently more risky as they do not retain the financial strength and capability of a larger entity beyond the assets within the project. Additionally, not all bids are based on an SPE ownership structure, and in fact, some RFP sellers exhibit robust levels of credit worthiness that are comparable to, or superior to, that of an investor-owned utility.

**Q. Do IPPs themselves have credit requirements in order to enter into bi-lateral transactions?**

A. Yes. PGE participates in the Northwest wholesale electricity market and several counterparties are IPPs. These parties commonly negotiate credit and collateral requirements as part of the enabling agreements necessary for purchasing and selling wholesale gas and electricity. These enabling agreements have margin call calculations, credit thresholds, and triggers that reflect the credit ratings and financial wherewithal of the counterparties. IPPs operating in the wholesale energy markets have been comfortable executing and abiding by the credit requirements within these enabling agreements.

**Q. Collins asks, "Why, given the accrual of experience with IPP's, would one presume a utility needed to have and should pay for investment grade credit from suppliers?" (NIPPC Exhibit 200, pg. 9 at 6-7). How do you respond?**

A. Our response is that the IPPs themselves and all other participants in the wholesale energy markets require a standard of credit protection that starts with investment grade credit (or equivalent credit enhancements) from their trading partners. PGE is simply implementing these industry best practices in the RFP scoring.

**Q. Collins found that PGE's credit scoring approach was lacking on 5 premises (NIPPC Exhibit 200, pg. 8-9). Do you agree?**

A. No. We discuss each of the five premises below.

**Q. Do you agree with Collins' first objection to PGE's use of credit rating agencies credit assessments?**

A. No. PGE agrees that the rating system is undergoing reform. Nevertheless, these reforms are tightening credit requirements and grading criteria, not relaxing the requirements. PGE is applying the industry best practices standard for assessing credit risk in using counterparty debt ratings as a proxy.

**Q. Do you agree with Collins' second objection that PGE's use of credit ratings is not transparent?**

A. No. In fact, PGE's 2007 RFP (see PGE Exhibit 202) specified in detail how PGE conducts its credit evaluation:

**"Credit Evaluation**

This category scores the creditworthiness of the Bidder. We will take into account the following credit considerations in our scoring:

- Debt and equity ratings
- Performance assurance
- Financial ratio analysis
- Default risk
- Credit concentration and liquidity
- Enforceability of contractual credit terms
- Bidder revisions to contract templates that may affect credit requirements"

**Q. Do you have any comments on Collins' third complaint regarding the alleged lack of a sufficient nexus to the credit of the entity that will hold the asset?**

A. Yes. PGE believes that there is a direct nexus between a bidder's current financial status and their ability to obtain project financing for a prospective power plant from a financial institution. PGE's RFP scoring accurately reflects the financial wherewithal of the seller at the time of bid submittal, so the scoring does capture the counterparty risk associated with the ability of the seller to complete the project and perform the obligations under a proposed PPA.

**Q. Fourth, Collins questions "what is it worth in price received to have triple A credit instead of triple B?" (NIPPC Exhibit 200, pg. 9 at 5-6). Can you respond?**

A. Yes. PGE does, in fact, differentiate between seller credit grades in its bid evaluation process by allocating more points to entities with a higher credit score. In addition, the credit rating is not the only metric PGE uses to measure creditworthiness and allocate points. Points associated with credit rating are combined with points allocated to the bid, based on certain financial ratios and other credit risk attributes.

**Q. Do you agree with Collins' fifth complaint that the PPA Seller submitting a bid may not be the entity owning the facility over time?**

A. Yes, but it does not diminish the validity of scoring counterparty risk as part of the bid evaluation process. While PGE acknowledges that there is a potential for changes in a seller's ownership and creditworthiness after short-list selection, this risk is largely mitigated by the terms and conditions that would be required during contract negotiations and prior to deal execution. Any changes in seller ownership and credit status after the deal is executed are mitigated through typical wholesale energy contract terms and conditions such as "material adverse change" clauses that address deterioration of credit quality through increases in collateral requirements and / or events of default. Other common contractual provisions that would mitigate the risk associated with seller change in ownership include:

- Buyer approval requirements for any sale or transfer of generation assets supporting the PPA;
- Requirements that generation assets can only be sold or transferred to a company with equal or better credit rating than the original owner / bidder;
- Buyer right to step-in and operate the plant assets in the event of default; and
- Requirement that seller must maintain a guaranty from an investment grade credit support provider.

Moreover, the fact that ownership of a PPA generation asset or project company could change over time does not diminish the prudency of assessing the seller's credit and performance risk at the time of bid evaluation.

**Q. Do you believe that changes in the evaluation of counterparty risk are appropriate?**

A. Yes. PGE proposes to more fully incorporate counterparty risk in our scoring matrix for future RFPs.

**Q. Can you summarize the changes you would propose that would address counterparty risk more accurately?**

A. Certainly. In addition to PGE's current RFP scoring method, we propose working with the IE to include in our non-price scoring section any changes in risk allocation that may result from bidder exceptions to our proposed standard contract template terms and conditions. More specifically, we propose as the following:

- Non-Negotiable contract terms for certain key contract terms and conditions: in order to account for the fact that bidder's edits of the template contract also affect counterparty risks, some contractual terms should be deemed non-negotiable. The acceptance in whole of these non-modifiable contract terms should be a threshold requirement for participating in the RFP. These non-modifiable contract terms could include, but may not be limited to:

  Seller must offer buyer the right to:

  - Step into the role of builder, operator or owner in the event of seller default;
  - Approve a merger or transfer of plant assets underlying a PPA;
  - Events of default and security requirements.

- Score all bids to reflect redline edits / exceptions of terms and conditions in the template contracts. The methodology for evaluating and scoring any contract exceptions would be done by the utility in consultation with the IE. Changes to contract provisions to be considered for score adjustment could include, but may not be limited to:
    - Change in law;
    - Change in regulation;
    - Addition of condition precedent or contract effectiveness;
    - Addition of no-fault termination clauses or conditions that alter or limit seller performance obligations ;
    - Conditions or provisions that establish caps or limitations on damages or remedies for performance failures;
    - Changes in events constituting *force majeure*;
    - Changes in performance assurance provisions;
    - Provision of environmental attributes.

The inclusion of the above recommendations would improve scoring of the bids to more appropriately reflect counterparty risk without prejudice to the structure of the proposal.

In addition, PGE suggests that the RFP process should be modified to include an evaluation and scoring of all bid structures that result in a direct balance sheet impact to the utility, such as capital lease treatment, consolidation of variable interest entities (VIE) or any other GAAP rule that may directly affect the financial statements of the buyer, and which are not currently captured in RFP scoring.

## III. Response to OPUC Staff's Testimony

**Q. Do you agree with Staff that the focus of the risk analysis in Phase II is risk to customers? (Staff Exhibit 100, pg. 3 at 21-22)**

A. Yes. PGE agrees that the focus of the risk analysis in Phase II is the risk to utility customers. We, therefore, believe that an effective bid scoring process is one that is designed to ensure that all proposed resources are assessed against a consistent set of criteria that captures all relevant factors which affect customer costs and benefits.

**Q. Do you agree with Staff that "the Commission has concluded that the bid evaluation process is biased towards the benchmark resource bid"? (Staff Exhibit 100, pg. 4 at 13-19)**

A. No. Staff alludes to the Averch-Johnson Effect that there is a tendency by the utility to substitute capital for labor in its profit-maximizing calculations. However, this is a high-level theoretical result that makes no specific forecast that would imply a tendency by a utility to bias its bid evaluations. We believe that the Commission concluded that utilities have an incentive to select benchmark resources because of the ability to place these investments in rate base, but the Commission did not conclude that the competitive bid evaluation methodology or process was itself biased. It is the goal of this phase of the docket to determine whether any improvements can be made in the evaluation and analysis of utility benchmark and competitive bids.

**Q. Do you agree with Staff that the current bid evaluation process could treat the benchmark resource bid and the IPP bid differently and that the different treatment would not be evidence of bias? (Staff Exhibit 100, pg. 6 at 3-13)**

A. Yes. As we have emphasized in our testimony, the bid evaluation process should be designed to assess the value and risk of each unique resource and bid, independent of ownership status. Further, we agree with Staff that "[i]f it turns out that the existing bid evaluation criteria reasonably account for differences in risk between two bids, then that is evidence that the bid evaluation criteria are free of bias." (Staff Exhibit 100, pg. 7 at 10-12)

**Q. Do you agree with Staff's criticisms of NIPPC's recommendations for a cost over-run adder? (Staff Exhibit 100, pg. 10 at 22-23)**

A. Yes. Specifically, we agree that any recommendation must include an examination of the current bid evaluation guidelines. It makes no sense to propose a cure when a diagnosis has not been made. As we have emphasized in our testimony, if the RFP scoring recognizes the value of construction cost guarantees (and conversely the risk of the absence of such guarantees), then construction cost risk has been accounted for, and an adder is not necessary. We believe that RFP bid scoring should favor proposals incorporating cost guarantees regardless of ownership status.

**Q. Do you share Staff's concerns regarding NIPPC's data and the methodology they used to derive the cost over-run adder? (Staff Exhibit 100, pg. 8 at 9-14)**

A. Yes. Staff is concerned about the small sample size used to derive this cost over-run adder (Staff Exhibit 100, pg. 11 at 17-23). We share these concerns. As we discussed earlier, Dr. Jacobs (PGE Exhibit 300) provides a detailed discussion of the data NIPPC used to calculate the cost over-run adder. He concludes that their data set is not adequate to distinguish the relevant cost estimates used to justify the bid and the final construction cost.

**Q. Staff has expressed concerns about the data set and methodology used to calculate NIPPC's heat rate degradation adder (Staff Exhibit 100, pg. 15 at 4-10). Do you share these concerns?**

A. Yes. Staff notes that the vintages of the plants in the data set "are not representative of gas plants that will be bid into future RFPs" (Staff Exhibit 100, pg. 15 at 12-13). Staff also recognizes that the data set consists primarily of observations for Simple Cycle Combustion Turbines and concludes that it is unlikely that valid inferences could be drawn from this data set for Combined Cycle Combustion Turbines. Dr. Jacobs' testimony includes a detailed critique of NIPPC's heat rate degradation estimates and provides alternative estimates based on a better data set. He concludes that, even with a superior data set, it is not possible to derive useful estimates of long-run heat rate degradation from available data.

**Q. Do you concur with Staff's analysis of heat rate degradation?**

A. Yes, for the most part. We agree with Staff's concerns regarding Monsen's analysis and proposed adders. As an example, we both believe that Monsen's analysis has data and methodological issues. While recognizing the limitations in the data set utilized by Monsen and, subsequently, Staff, we again point out that the correct metric against which to measure heat rate degradation is the "as bid" heat rate. As we stated in our direct testimony, the appropriate heat rate for bid evaluation is the long-run average degraded heat rate. We also note that Staff's analysis did not adjust for changes in plant dispatch / operation.

Staff supports the results from their "Alternative Five" which indicates a 0.11% degradation in heat rate, which is effectively zero. However, if Staff had the data needed to adjust for changes in plant dispatch and operation, and were able to compare actual heat rates to the projected lifetime average heat rate, we believe that their analysis would not support a heat rate adder.

## IV. Summary and Conclusions

**Q. Please summarize your recommendations to the Commission.**

A. First, we recommend that the Commission reject the use of adders for heat rate degradation, cost under / over runs, and wind capacity factor.

Second, we recommend that the Commission continue to maintain its focus on potential improvements in the analytic framework and process for RFP bid evaluation.

Finally, if the Commission finds that improvements are needed for any of the four issues identified for this phase of the docket, we recommend that the Commission direct the utilities 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.

## List of Exhibits

| **PGE Exhibit** | **Description** |
|---|---|
| 201 | Standard & Poor's *Principles of Credit Ratings* |
| 202 | PGE 2007 Request for Proposals |

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1182 Phase II

**PORTLAND GENERAL ELECTRIC COMPANY**

Direct Testimony and Exhibits of

***Jonathan Jacobs***

PGE
Portland General Electric

**January 14, 2013**

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# I. Introduction

**Q. State your name, title, and business address.**

A. My name is Jonathan M. Jacobs. I am a Managing Consultant for PA Consulting Group, Inc. My business address is One California Plaza, Suite 3840, 300 South Grand Avenue, Los Angeles CA 90071.

**Q. Please describe your educational background.**

A. I hold the degree of Doctor of Philosophy in Mathematics, awarded by the University of Wisconsin-Madison in 1985. My undergraduate degree is an S.B. from the University of Chicago with a concentration in mathematics.

**Q. Please briefly describe your professional background.**

A. I have been in the electricity industry for almost twenty-three years, and have been with PA Consulting Group for the last twelve years. I have advised electric utilities, merchant power producers, system operators, and other clients on various aspects of energy procurement, resource planning, ISO markets, pricing and forecasting. Of particular interest to this proceeding, for the last six years I have been an Independent Evaluator of resource solicitations for San Diego Gas & Electric Co.

Prior to joining PA I was employed for three years by PG&E Energy Services, where I was Director-Market and Financial Modeling. Before that I worked for seven years for Pacific Gas & Electric Company, generally on mathematical modeling for electricity supply planning.

My curriculum vita is provided in Section III.

**Q. On whose behalf are you testifying?**

A. I am providing reply testimony on behalf of Portland General Electric Company.

**Q. To what testimony are you replying?**

A. I am primarily replying to the testimony of Northwest and Intermountain Power Producers Coalition (NIPPC). I will also refer to the testimony of the Oregon PUC Staff, both for context and to address the meaning of "risk" and "bias", which are two key terms used in this Proceeding. I will also reference some earlier comments submitted by NIPPC, to which the Staff testimony makes reference.

**Q. What are the conclusions of your testimony?**

A. I conclude that the heat rate degradation and cost over-run adders proposed by NIPPC's witness, William Monsen, are not appropriate.

His historical analysis of heat rate degradation used inappropriate data and had computational flaws, including a failure to correct for plant dispatch. I did a similar analysis correcting for these issues and obtained no evidence of statistically significant heat rate degradation unexplained by dispatch. The baseline of his computation does not appear to represent how Oregon utilities estimate heat rates of benchmark bids.

In addition, Mr. Monsen's estimate of a cost over-run adder is based on historical data from California. It is difficult to find historical comparisons for cost over-runs relative to benchmark bids, because again the historical baselines are often not comparable to benchmark bids. That is the case for the first of Mr. Monsen's examples that I examine. The second example seems to be a type of over-run that is not specific to utility benchmark bids; if a similar situation occurred to an IPP project, I think it is likely that the Power Purchase Agreement would permit the IPP to pass the cost on to customers. Finally, I do not believe that he has provided sufficient justification for including "deferred construction costs" in such an adder.

## II. Bias, Risk and Bid Adders

**Q. According to Staff, what are the goals of this phase of UM-1182?**

A. Basically, this phase of the Proceeding is intended to analyze four different risks: Cost Over-run/Under-run Risk; Wind Capacity Factor Risk; Counterparty Risk; and Heat Rate Degradation Risk. Staff states that the goals are to determine how utilities currently account for each risk in the bid evaluation process; whether the evaluation methods are biased in favor of benchmark or IPP bids; and to make recommendations as to how to remove any bias.

**Q. Generically, how do utilities evaluate bids?**

A. The most natural way to think of evaluating bids is to assign a numerical value to each bid (a score) and to choose the bid with the highest score. This appears to be the way that Portland General and PacifiCorp both evaluate bids, based on their direct testimony. The numerical score is supposed to fairly represent the value of each bid. It can be easy to see the intended relationship between score and value, if for example "value" is taken to mean expected cost to customers. The numerical score can also include various qualitative factors.

If a score is based on multiple attributes or factors, the utility can try to combine them, usually by adding them up. For example, PacifiCorp states it adds together a price score on a scale of 1-70, and a non-price score on a scale of 1-30. In doing this, the utility is explicitly or implicitly scaling the different factors.

Finally, the utility could determine not to scale the factors, in which case the bids would not be measured against a single standard of value. If the utility took this approach it would look for "non-dominated" bids. A bid is "dominated" if there is another bid which is at least as good on every factor, and better on one. This strategy may be unobjectionable if the utility seeks to contract with several resources, but if the utility has to choose only some of the non-dominated resources, it still needs to determine and explain a selection rule.

**Q. What does it mean to say an evaluation method is biased?**

A. Generally speaking, an evaluation method is biased if it does not consistently rank bids according to their value. For example, if the method were based on numerical scores and the method assigned a higher score to bid A than to bid B even though B was more valuable, the method would be biased.

There is also a statistical definition of bias which is particularly relevant here. Suppose that the utility scored bids based on a formula that is based on certain parameters of the bids, and those parameters are not known with certainly. The utility or the bidder has to estimate those parameters. When dealing with an unknown parameter it is customary to assume it has some kind of a probability distribution – for example, to assume that the price of natural gas per MMBtu, while unknown, has a 30% chance of being under $3.00, a 40% chance of being between $3.00 and $4.00, and a 30% chance of being above $4.00. An unbiased parameter estimate is, by definition, one that equals the expected value of its probability distribution. Of course, the "true" probability distribution is also unknown, but it is common to use the observed frequency distribution of similar data, such as historical gas prices, as a proxy.

Using this definition one would say that an evaluation method based on a numerical formula is (systematically) biased if it is based on parameters estimated in such a way as to differ from their expectations. It would be biased in favor of a particular type of resource (such as utility benchmark resource) if the estimates of some parameter(s) of those resources were systematically skewed in such a way that bids received higher scores than if the expected parameter values had been used instead.

**Q. Does opening testimony reflect this view of "bias"?**

A. Yes. In particular, NIPPC's direct testimony alleges that utility estimates of several bid parameters – capital cost, wind capacity factor and heat rate degradation are biased.

**Q. What is a "bid adder"?**

A. A bid adder would be a rule for adjusting a bid score. A bid adder defined in this docket would be intended to eliminate bias. A bid adder could also introduce a preference for bids with certain characteristics either intentionally or unintentionally.

**Q. Does any respondent propose bid adders?**

A. NIPPC proposes an adder to the capital costs of utility benchmark bids. They also propose a modification to be applied to the heat rates of utility benchmark bids, which is more of a bid modification than an adder.

**Q. Is there another use for the statistical definition of bias?**

A. Yes. Bid evaluation often involves a variety of uncertainties, including for example hydro conditions, fuel prices, and load. Each combination of possible outcomes of those uncertainties is a scenario. A bid score formula can involve these values, and could produce a single numerical answers for each scenario. In principle one could form the expected value of those answers. The expected value is the weighted average of the different possible numerical values, each one weighted by its probability. Of course, even if the numerical formula correctly reflects the resource value under each scenario, its expected value may not correctly reflect the resource value in an uncertain world.

**Q. How could the expected value not correctly reflect the resource value?**

A. It is often assumed that we prefer certainty to uncertainty and therefore would prefer a resource whose cost or score did not vary much from scenario to scenario, even if the expected value of its score were the same or less than that of another resource with much more score variability. In finance that variability is called "risk". If customers prefer a less variable cost, an evaluation method that does not penalize variability would be systematically biased.

**Q. Is it necessary to address this kind of "bias"?**

A. I don't believe that any of the opening testimony addresses the presence or absence of such bias in utility bid evaluation. The Staff Opening Testimony specifically faults NIPPC's submitted "Phase II Report" for not addressing "risk" as variability. Staff bases this on the Commission's language in Order 12-324, which characterizes the four issues to be addressed as "risks".

I believe from context that the Commission used the word "risk" in a common language sense, to identify these as issues of concern. In the materials that I have reviewed, I have not seen the need to address variability as a consistent theme. It is true that NIPPC states that fixed-price power purchase agreements are valuable because they eliminate upside cost risk, and that utilities believe traditional cost-based ratemaking is valuable because it allows customers to capture cost reductions. But no party appears to present any evidence as to whether utility customers value the reduction of uncertainty, and how much they would pay for a certain amount of cost reduction.

### A. Heat Rate Degradation

**Q. What is the issue of heat rate degradation?**

A. The heat rate of a power plant is the ratio of fuel use to electric energy production. Greater efficiency is associated with using less fuel to produce the same amount of electric energy, so lower heat rates are associated with higher efficiency. Heat rates of fossil-fired power plants generally increase over time, although regular maintenance can restore most of the lost efficiency. Again, heat rate degradation is an increase in the numerical value of the heat rate, relative to a particular value associated with the generator. I call that value the "baseline" for the degradation. Photovoltaic plants similarly decline over time, in that case manifested as a reduction in capacity factor for constant insolation, but I believe that only thermal plants are at issue here. Heat rate degradation due solely to aging will reduce the net benefit (increase the cost) of a power plant.

**Q. Are there any other reasons for the observed efficiency of a power plant to change over time?**

A. Yes, especially if one is referring to the average efficiency. Average heat rates can increase due to changes in dispatch (the plant can be dispatched away from its optimal operating point, for example to provide ancillary services) or the addition of emissions controls. If the heat rate degrades due to plant dispatch, it is likely that the system operator has determined that the operational benefits of the revised dispatch exceed the costs and a cost-only computation will not capture that. If a heat rate degrades due to an additional emissions control not connected with new regulations, the control may well have been installed or imposed to avoid unexpectedly high emissions costs from other resources, and again the benefit (avoided emissions cost) should exceed the cost increase.

**Q. What does the utilities' opening testimony say about heat rate degradation?**

A. Portland General describes their benchmark bids as based on "long-term degraded heat rates". They say that they base their heat rate estimate on the "new and clean" heat rate and "non-recoverable degradation" information provided by turbine manufacturers, as well as "long-run average degradation" over the maintenance cycle. PacifiCorp says they begin with a "new and clean" heat rate and apply "the heat rate degradation curve, which is supplied by the OEM." Idaho Power says they assume heat rates degrade "based on the manufacturer's specifications."

**Q. Given the utilities' description of how heat rate degradation is accounted for in their current bid evaluations, could there be sources of bias in the heat rate estimates?**

A. Yes, possibly. The manufacturers' estimates of heat rates could be incorrect or based on unrealistic operating conditions. And, the utilities could have applied the manufacturers' degradation forecasts incorrectly. Although the effects of these potential sources of bias seem to be small, I can see the value of testing them.

**Q. What does other parties' opening testimony say about heat rate degradation?**

A. William Monsen, testifying on behalf of NIPPC, described an analysis he conducted, from which he estimated the average degradation in heat rate for utility-owned generation to be 8%. He recommended that this be used as the floor for the average degradation in the heat rate of any utility benchmark resource over time.

Robert J. Procter testified on behalf of the Commission Staff. He first noted that "none of [NIPPC's] adders consider how the utility's current bid evaluation methodology addresses the four risks" (Staff Exhibit 100, pg. 10 at 19-20) This is in a section about the Cost Over-run / Under-run analysis but it is clearly meant to apply to NIPPC's analysis as a whole, that is, to the Heat Rate Degradation as well. In other words, there have been no alternatives presented to the utilities' descriptions of how they estimated heat rates. Mr. Procter then critiqued an earlier presentation of Mr. Monsen's historical analysis.

**Q. What does Mr. Monsen recommend in his testimony?**

A. He recommends that the IE ensure that utility benchmark bids enforce an average heat rate degradation of 8%.

**Q. Does he recommend an 8% adder to heat rates in benchmark bids?**

A. No, he recommends that the IE ensure that heat rates incorporate 8% average degradation.[1] I infer that he means the average heat rate should be 8% larger that the heat rate in an un-degraded state. He also says that if a benchmark bid can be shown to incorporate some degradation, the adder should only be large enough to bring the average degradation up to 8%. He does not give any evidence as to whether benchmark bids already include degradation.

**Q. On what basis does he make this recommendation?**

A. He says it is based on analysis of historical figures for power plant heat rate degradation. He does not compare the accuracy of his method to the accuracy of the forecasts in utility benchmarks, in other words, does not determine which method is really less biased.

[1] Northwest & Intermountain Power Producers Coalition (NIPPC), *Technical Approach to Developing Bid Adders for Utility-Owned Generation Proposals*, Jan. 31, 2012. It appears as attachment 1 to Northwest & Intermountain Power Producers Coalition (NIPPC), "Comments of the Northwest and Intermountain Power Producers Coalition" in Docket UM-1182, March 19, 2012.

**Q. Could an analysis like NIPPC's be used to reveal biases in the estimation of heat rate degradation in utility benchmark bids?**

A. Conceivably, but the analysis would have to use appropriate data, correct as necessary for plant commitment and dispatch, and have a baseline similar to the benchmark bids themselves.

**Q. What do you mean by "appropriate data"?**

A. Historical degradation in power plant heat rates might imply that the heat rates of new power plants will degrade by a like amount, but only if it is reasonable to think that the plants are similar. There is no evidence that the majority of plants whose heat rates NIPPC studied were similar to modern gas-fired combined cycle plants. Furthermore, there is no evidence that the maintenance practices applied to the power plants in the NIPPC database are similar to those in use today. "Appropriate data" would mean a database consisting of modern gas-fired combined cycle plants with Long Term Service Agreements, which have been maintained according to manufacturers' recommendations.

**Q. What do you mean by "correct as necessary for plant commitment and dispatch"?**

A. NIPPC has only considered average heat rates, which depend heavily on operation. A turbine-generator's heat rate varies with its operating level. The average heat rate also depends on the number of times a plant is started, because each start requires an additional amount of fuel that is not effectively converted to electricity. Finally, a combined-cycle plant often contains one or more combustion turbines and one or more heat recovery steam generators, and the efficiency of the plant can vary with the number of components operating. These factors are controlled by the plant's commitment and dispatch – roughly, by the amount of electricity it produces, or is scheduled to produce.

If the plant is scheduled to produce less electricity it will probably operate less efficiently, at a higher heat rate. That less efficient operation should not be interpreted as degradation of the plant. I illustrate, later in my testimony, an analysis that tries to correct for changes in dispatch, or more specifically, for changes in electricity production.

**Q. Is it possible also to correct for maintenance?**

A. Perhaps one could control for the amount of time since the last major maintenance, if it were possible to get data about historical maintenance schedules. But if you already had historical maintenance data, you should be able to limit your database to plants that have been maintained at proper intervals.

**Q. What do you mean by "a baseline similar to the benchmark bids themselves"?**

A. NIPPC reviews a set of power plants and compares historical annual average heat rates for each plant to a baseline which is not necessarily consistent with the way utilities estimate heat rates; it is not derived from manufacturer's data for heat rates and their degradation. (There are actually different baselines in the original NIPPC analysis and the testimony, as I will explain.) To evaluate the potential bias in the utilities' values one would have to compute the average difference between the "actual" heat rates and those utility forecasts, or between the "actual" heat rates and proxy forecasts based on manufacturers' data. Different turbine models or configurations could have different amounts of degradation, which could still be accounted for in the manufacturers' data. The baseline for an analysis like NIPPC's, if the goal were to determine whether the utility forecasts were biased, would be a hypothetical forecast constructed for each plant using the utilities' methods and contemporary manufacturer information.

**Q. Do you agree with Staff's critique of the original NIPPC analysis?[2]**

A. Staff raised three issues. The first, as I understand it, was that NIPPC did not address risk in the sense of variability. I am not in a position to know if it was the Commission's intention that they do so. Second, Staff raised data and methodological concerns with NIPPC's analysis, which I share. As will be seen below, I have conducted my own analysis and do not agree with NIPPC's results. Third, Staff said that NIPPC did not "consider how contract terms of specific bids influence ratepayer exposure." This could mean the consideration of whether manufacturers' guarantees or improved maintenance scheduling, reflected in long-term service agreements mitigate any degradation that had been observed in the historical record; I did not go beyond the historical record in this testimony to estimate such mitigations.

**Q. What were Staff's data and methodological concerns?**

A. That the NIPPC dataset included data as early as 1981 and power plants that could have come online even earlier; that the dataset is dominated by simple cycle combustion turbines; that NIPPC did not perform adequate sensitivity analysis; and that NIPPC did not weight the results by generation.

**Q. What did the original NIPPC analysis conclude?**

A. In that analysis, NIPPC stated that they observed an average heat rate increase of 5.6%.

**Q. Does the original NIPPC analysis support Mr. Monsen's figure of 8% for heat rate degradation?**

[2] The term "original NIPPC analysis" will be used to refer to the analysis described in the *Technical Approach* document cited in note. This is done to distinguish it from the analysis underlying NIPPC's opening testimony, which appears to have been slightly different but is not completely specified.

A. Not directly, since he recommends a figure that is almost half again as large as the average degradation stated by earlier analysis. Either the analysis has changed, or he has another justification for the larger adder.

**Q. Are the NIPPC opening testimony and the original NIPPC analysis based on the same dataset?**

A. It appears so.

**Q. What is that dataset?**

A. NIPPC's dataset was developed from Federal data and used for an econometric analysis published in an academic paper. According to that paper the dataset was based on temporally aggregated data collected by Federal agencies, in other words, generation and fuel usage over periods of months or years, irrespective of the operating tempo during those periods.[3]

**Q. Are there any differences in definitions or assumptions between the original NIPPC analysis and the opening testimony?**

A. There appear to be at least two.

1. The "degradation" is estimated differently. In the original NIPPC analysis, the "degradation" of an individual power plant's heat rate was estimated using the average of the ratios of annual observed heat rates to the earliest heat rate for that plant in the database. From that averaging, any improvements of 7.1% or greater were excluded. Mr. Monsen's testimony says that instead of using the first observed heat rate as a base, he used the absolute minimum observed for the plant, which could be an observation prior to some of the "non-recoverable degradation" or at the most efficient

[3] Fabrizio, K.R., N.L. Rose and C.D. Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," **American Economic Review** 97 (September, 2007), pp. 1250-1277.

point in a maintenance cycle. In this case Mr. Monsen does not say that he eliminated any improvements of 7.1% or greater.

2. The original NIPPC analysis used a simple average of all the heat rate changes. In his testimony, Mr. Monsen says he used a weighted average, weighed by capacity factor.

**Q. Did the NIPPC opening testimony obviate any of Staff's data and methodological concerns?**

A. Perhaps. NIPPC changed from using a simple average to an average weighted by capacity factor (not the same as generation). According to Staff's testimony, weighting by generation would have reduced the estimated average degradation from 5.6% to 0.11%; yet NIPPC has instead increased its recommendation to 8%.

**Q. Is the NIPPC dataset appropriate?**

A. No. It was dominated by plants using old technology, and does not reflect current maintenance practices. Furthermore, NIPPC does not appear to have made any attempt to take account of historical dispatch or operating tempo.

**Q. Did you attempt to construct a more appropriate database?**

A. Yes. PA Consulting staff under my direction extracted a database similar to the one used by NIPPC, suited for this particular purpose, from data collected by the Energy Information Administration (EIA) in the Annual Electric Generator Report (Form 860) and Power Plant Operations Report (Form 923) for 2003-2011. This database contains monthly volumes of fuel used and net electric generation (net means, after subtracting station service, which means the power used in the plant itself). From those monthly volumes one can also accumulate annual volumes. The average heat rate in any period is the ratio of fuel used to net electric generation. We then computed period-to-period changes in the heat rate and generation volume (deltas) for each plant.

**Q. What power plants did you include in your analysis?**

A. We included all combined cycle plants in the EIA database, other than single-shaft plants. The EIA dataset separately identifies the combustion turbine part of the plant from the steam turbines, labeling them by prime mover codes "CT" and "CA". We aggregate the fuel use and generation from the CT and CA parts of each plant. We excluded any units labeled with other prime mover codes, including "CS" (single-shaft combined cycle). Finally, we eliminated plants that were identified as combined heat and power (CHP).

**Q. Why did you exclude single-shaft plants?**

A. There are considerably fewer of them, and the mechanical differences could change their heat rate degradation.

**Q. Did you exclude plants of capacity less than 150 MW, as NIPPC did in its original analysis?**

A. No. NIPPC did not explain this limitation; I thought it may have been put in to exclude aeroderivative gas turbines. I did not think it was necessary to include such a limit in PA's dataset as we were restricting to non-CHP CCCT units, and because it was not a precise specification – NIPPC did not state whether they meant "summer capacity" or "winter capacity". I felt it was more important to exclude plants with low net generation, since then a disproportionate amount of their fuel is used for startups or for station service. Therefore, in my analysis of annual data I excluded years in which the plant generated less than 13,000 MWh – that's about a 1% capacity factor for a 150 MW plant. In my analysis of monthly data, which I will describe later, I excluded months in which a plant generated less than 1,200 MWh, which would have been the production of a 150 MW plant running at full load for eight hours.

**Q. If you excluded a single month or year for a power plant, in the middle of the period of record, how did this affect your computation of the deltas?**

A. I computed the change from one period to the next period in the database, skipping any periods that were excluded.

**Q. Did you also exclude non-utility power plants, as in the original NIPPC analysis?**

A. No. I don't think NIPPC has claimed that utility plant heat rates degrade more than non-utility plants, only that utility benchmark bids may not reflect "typical" degradation for a class of plants.

**Q. Did you exclude any particularly large heat rate improvements, as in NIPPC's original analysis, or particularly large degradations?**

A. No. Large improvements could be attributable to operation at more efficient dispatch points with fewer starts. Similarly, large degradations could be attributable to operation at less efficient dispatch points for shorter periods, with more startups. Neither can be automatically attributed to data errors.

**Q. You computed period-to-period changes, while Mr. Monsen's testimony addressed differences from a single baseline for each generator. How does that affect the quality of the analyses?**

A. Aging, and wear and tear on a power plant, are not the only reasons average heat rates change. Plant efficiency also responds to other factors, including dispatch. The best observed heat rate, which was the baseline in Mr. Monsen's testimony, does not necessarily represent the least degraded state; it could represent the period in which other influences were most favorable. If so, the choice of baseline would magnify the impact of extraneous factors. The period-to-period change reflects both degradation and those extraneous factors, but we can correct for at least one (quantity of production) and try to average out the rest. I believe that correction for variation in production eliminates one potential bias in the analysis, and averaging out the impacts of random changes in extraneous factors eliminates another. Then if the average period-to-period degradation is significantly different from zero, one can compound it over multiple periods to estimate the average degradation over the plant lifetime.

**Q. Please provide some general descriptive statistics of your dataset.**

A. There were a total of 281 power plants in the database. The database covered 9 years (108 months) so there were at most 9 annual observations (deltas) per plant. There were a total of 1814 annual deltas in the database (6.5 per plant).

**Q. What did you observe about heat rate changes?**

A. The average annual heat rate change was 0.53%, but the average logarithmic difference was –0.35%, which is an improvement rather than a degradation.

**Q. What do you mean by the logarithmic difference?**

A. The logarithmic change in heat rate is the natural logarithm of the ratio of two successive heat rates. If the two heat rates are r1 and r2, their difference is $r2 - r1$ but the logarithmic difference is $\ln(r2/r1)$. It happens also to equal the difference of their logarithms, $\ln r2 - \ln r1$.

**Q. Is there an advantage to using the logarithmic difference?**

A. Yes. We are really interested in the effects of multiple years of heat rate changes, to get a long-run average. It's a compounding process, like compound interest. It is relatively easy to compound logarithmic changes, you just add them. Averaging the percentage changes in heat rates gives you a biased estimate because it overemphasizes positive changes (increases), as the example I am about to give will show. There is a cycle over which heat rate degradation is at least partly repaired by maintenance. Suppose that in one year, the heat rate goes up by 50%; and in the next year, thanks to maintenance, it goes back where it was. That's only a 33% decrease (from 150% back to 100%) so the average of those changes would be 8.7% (the average of +50% and –33%); yet the total change is zero. The logarithmic changes will have an appropriate zero average, because the logarithms of 1.5 and 0.67 are equal and opposite.

**Q. Is there an advantage to using the logarithmic difference?**

A. Yes. We are really interested in the effects of multiple years of heat rate changes, to get a long-run average. It's a compounding process, like compound interest. It is relatively easy to compound logarithmic changes, you just add them. Averaging the percentage changes in heat rates gives you a biased estimate because it overemphasizes positive changes (increases), as the example I am about to give will show. There is a cycle over which heat rate degradation is at least partly repaired by maintenance. Suppose that in one year, the heat rate goes up by 50%; and in the next year, thanks to maintenance, it goes back where it was. That's only a 33% decrease (from 150% back to 100%) so the average of those changes would be 8.7% (the average of +50% and –33%); yet the total change is zero. The logarithmic changes will have an appropriate zero average, because the logarithms of 1.5 and 0.67 are equal and opposite.

**Q. But is this really comparable to NIPPC's analysis? They only looked at power plants in non-restructured states.**

A. NIPPC took their data from a paper that tried to show that electric industry restructuring was associated with increased power plant efficiency. That paper emphasized that it was addressing labor and non-fuel operation and maintenance costs, not heat rates – in fact the authors say "the data do not suggest gains in fuel efficiency from restructuring within our sample."[4] But, their dataset only extends to 1999, and restructuring had only just started at that point. A more recent paper studies data up to 2006 and concludes that there is a difference in fuel efficiency between power plants in restructured and non-restructured states – but only if "restructuring" includes significant retail load migration, not just ISO wholesale markets.[5] That paper includes a table indicating the first year in which a market is considered fully restructured, by state. I excluded data from power plants in restructured states, beginning in each case with the first year in which the state's electricity market was considered restructured. This left me with 1,040 annual observations. The mean of the annual heat rate changes in this restricted dataset was 0.26%, and the mean of the annual logarithmic changes was -0.09%.

**Q. You mentioned earlier that heat rate changes can be caused by the way units are dispatched, and that you tried to correct for that. How does your dataset allow you to take account of dispatch?**

A. Primarily by using monthly observations. The fundamental problem is that when plants are dispatched below their optimal operating points their efficiency is reduced. Furthermore, when plants are committed for short periods of time, their fixed operating costs (startup fuel) become more significant and increase the average heat rate. It is hard

[4] Fabrizio et al., *ibid.*, p. 1269. They go on to say that their annual data are too aggregated to provide precise estimates of heat rate changes.
[5] Craig, J.D. and S.J. Savage, "Market Restructuring: Competition and the Efficiency of Electricity Generation: Plant-level Evidence from the United States 1996 to 2006," *Energy Journal* 34.1 (2013) pp. 1-31.

to detect these effects using annual data, because dispatch can vary significantly from season to season. Historical monthly generation and capacity factors show much more variability than annual figures. PA's dataset includes monthly generation and fuel consumption, from which we were able to compute monthly heat rates. Dispatch happens over shorter intervals, but the dispatch over a month should still be more uniform than over a year.

**Q. Are there any other advantages to using monthly data?**

A. Yes. I believe we are better able to test for heat rate degradation during the first year of operation (the "non-recoverable degradation" that Portland General Electric mentions, and to which NIPPC also alludes in their January report). That is because the first year of operation is often not coincident with a calendar year.

**Q. Do you conduct any special data modeling to capture dispatch effects?**

A. Yes. If heat rates are related to the level of generation, then the change in heat rate from month to month should be related to the change in generation. Heat rate degradation associated with aging would be unexplained by the change in generation. Therefore, I fit a model of the logarithmic change in heat rate as a function of the logarithmic change in generation.

**Q. You mentioned "logarithmic change" earlier; why did you choose to use only the logarithmic change in this analysis?**

A. Suppose that the amounts of electricity production in two successive periods are g1 and g2. The simple difference is $\Delta g = g2 - g1$, but if we just use $\Delta g$ we have a scaling problem: large plants will have large generation amounts and large $\Delta g$ values just because of their size, not because of the relative magnitude of the change. In that case one might want to measure the change in generation by the ratio of one period's amount to the next: ρg = g2/g1. Unfortunately, ratios are not symmetric: if you go from 1,000 MWh generation to 2,000 MWh the ratio is 2, but if you go from 2,000 MWh to 1,000 MWh the ratio is 0.5. Now suppose the heat rate at 2,000 MWh of generation is 8000 Btu/kWh but at 1,000 MWh it degrades to 8,100 Btu/kWh. Using ratios it is hard to define a consistent relationship between the change in heat rate and the change in generation:

**Table 1. Heat rate vs. generation, using ratios**

| | | Generation (MWh) | Heat rate (Btu/kWh) | Impact* |
|---|---|---|---|---|
| (a) | | 1000 | 8100 | |
| | | 2000 | 8000 | |
| | Ratio | 2 | 0.988 | 0.494 |
| (b) | | 2000 | 8000 | |
| | | 1000 | 8100 | |
| | Ratio | 0.5 | 1.0125 | 2.025 |

*Impact of generation on heat rate, measured as ratio of heat rate change to generation change.

The asymmetry in the ratios is eliminated by taking their logarithms. In the example illustrated below:

**Table 2. Heat rate vs. generation, using logarithms**

| | | Ln Generation | Ln Heat rate | Impact* |
|---|---|---|---|---|
| (a) | | 6.907 | 9.000 | |
| | | 7.601 | 8.987 | |
| | Difference | -0.694 | 0.013 | -0.019 |
| (b) | | 7.601 | 8.987 | |
| | | 6.907 | 9.000 | |
| | Difference | 0.694 | -0.013 | -0.019 |

*Impact of generation on heat rate, measured as ratio of logarithmic heat rate change to logarithmic generation change.

Using logarithms has the additional value that "no change" is represented by a value of 0 rather than 1. It is quite common to use logarithmic changes in models like this.

**Q. What is the specific form of the mathematical model used to correct for dispatch?**

A. Mathematically we fit a model of the following form:

(1) $\Delta \text{Ln HR} = \alpha \Delta \text{Ln Gen} + \Gamma$

Where $\Delta$Ln HR is the change in the natural logarithm of a power plant's heat rate from month to month (logarithm of the ratios of successive monthly generation numbers), $\Delta$Ln Gen is the change in the logarithm of its generation.

**Q. What do the coefficients of model (1) mean?**

A. The coefficient $\alpha$ controls the size of the correction for the generation level. The term $\alpha\Delta$Ln Gen represents how much of the monthly heat rate change – degradation or improvement – we are able to attribute to the change in average generation level. The intercept $\Gamma$ is the average of what's left. NIPPC's analysis produces an average of the heat rate degradation, but in this model $\Gamma$is the average after eliminating the effect of changes in the generation level. I would call it the underlying heat rate degradation. I have used monthly data and logarithms, so to get the annual underlying heat rate degradation you have to multiply by 12 and undo the logarithm. What you get is $e^{12\Gamma}$.

**Q. Does this approach correct for all the effects of dispatch and commitment?**

A. No. This is a partial solution. To get a better correction, though, one would need data at a very fine time scale, or at least the number of startups in each period.

**Q. Please provide some general descriptive statistics of your monthly dataset.**

A. There were a total of 269 power plants in the dataset, fewer than in the annual dataset. I mentioned above that I eliminated any months in which a plant generated less than 1,200 MWh; in addition, I ignored any plant for which there were less than 23 months of valid values for ΔLn HR and ΔLn Gen left after all the other exclusions. The dataset covered 9 years (108 months) so there were at most 107 observations (deltas) per plant. The average number of observations was 80.5; 27 plants had the maximum possible number of observations (107) and four had the minimum allowed (23). 107 of the plants were installed during the period of record of the database and therefore had their first full year of operation during that period. The variables of interest are ΔLn HR, ΔLn Gen and FirstYear, which equals 1 for the first 12 months after the plant begins operation and 0 thereafter:

**Table 3. Statistics of the monthly observations**

| Variable | Observations | Mean | Sample standard deviation |
|---|---|---|---|
| <u>Overall</u> | | | |
| $\Delta$Ln HR | 21,663 | -0.000679 | 0.1238 |
| $\Delta$Ln Gen | 21,663 | 0.00598 | 0.8569 |
| First Year | 21,663 | 0.0665 | 0.2492 |
| <u>Non-restructured</u> | | | |
| $\Delta$Ln HR | 12,345 | -0.00029 | 0.1260 |
| $\Delta$Ln Gen | 12,345 | 0.00303 | 0.8647 |
| First Year | 12,345 | 0.0715 | 0.2577 |

This seems to imply that heat rate doesn't degrade but improves (decreases) over time; however, this value is not really significant. The 2-sided t-test indicates that based on the entire dataset we can only be about 60% confident that the mean of ΔLn HR is nonzero, and based on the data from "non-restructured" states we can only be 20% confident in such a statement.

**Q. What were the results of model (1)?**

A. Recall the structure of model (1):

$$(1) \qquad \Delta \text{Ln HR} = \alpha \Delta \text{Ln Gen} + \Gamma$$

The regression statistics are as follows:

**Table 4. Model (1) applied to the full monthly dataset**

| | |
|---|---|
| $R^2$ | 16.9% |
| Degrees of freedom | 21,662 |

| | Coefficients | Standard Error | t Stat | Confidence |
|---|---|---|---|---|
| $\Gamma$ | -0.00032 | 0.00077 | -0.4223 | 33% |
| $\alpha$ | -0.05937 | 0.00089 | -66.359 | 100% |

In the coefficient table, "Confidence" means how confident we can be that the given coefficient is really nonzero based on the p-value of a 2-sided t-distribution. The $R^2$ value means there is a great deal of unexplained variation in $\Delta$Ln HR, but the high confidence that $\alpha$ is significant indicates that the mean degradation (the apparent monthly heat rate improvement) is explained by the change in generation.

Using the data from "non-restructured" states yielded similar results, with even less confidence that the corrected estimate $\Gamma$is different from zero:

**Table 5. Model (1) applied to non-restructured states**

| | |
|---|---|
| $R^2$ | 17.0% |
| Degrees of freedom | 12,344 |

| | Coefficients | Standard Error | t Stat | Confidence |
|---|---|---|---|---|
| $\Gamma$ | -0.00011 | 0.00103 | -0.1046 | 8% |
| $\alpha$ | -0.06003 | 0.00120 | -50.227 | 100% |

Q. **Did you also attempt to test for "non-recoverable degradation" as opposed to other heat rate degradation?**

A. Yes. I tried several approaches. First, I computed the mean logarithmic change in heat rate for data from the first year of plant operations (where the variable FirstYear equals 1) and compared it both with the average over all data, and with a similar average restricted to plants installed during the first year of record ("new plants"). I computed these averages using the entire dataset and also using only the data from non-restructured states:

**Table 6. Comparing heat rate changes in first year of operation to other years**

| | All states | Non-restructured states |
|---|---|---|
| All plants, all months | -0.00068 | -0.00029 |
| New plants, all months | -0.00164 | -0.00251 |
| First year only | -0.00842 | -0.01346 |

Secondly, in order to correct for the fact that generation should be increasing as a plant enters operation I estimated a similar model that includes the variable FirstYear to identify degradation during the first year of operation:

(2) $\Delta \text{Ln HR} = \alpha \Delta \text{Ln Gen} + \beta \text{FirstYear} + \Gamma$

With this model, the corrected heat rate change would be $\beta + \Gamma$ per month during the first year of operation, and $\Gamma$ per month thereafter.

I estimated model (2) on the full monthly dataset and got the following regression statistics:

**Table 7. Model (2) applied to the full monthly dataset**

| | | | | |
|---|---|---|---|---|
| $R^2$ | 16.9% | | | |
| Degrees of freedom | 21,662 | | | |
| | Coefficients | Standard Error | t Stat | Confidence |
| $\Gamma$ | $8.33 \times 10^{-5}$ | 0.00079 | 0.1050 | 8% |
| $\alpha$ | -0.05935 | 0.00089 | -66.339 | 100% |
| $\beta$ | -0.00612 | 0.00308 | -1.9896 | 95% |

I also estimated model (2) restricted only to data from non-restructured states:

**Table 8. Model (2) applied to the non-restructured states**

| | | | | |
|---|---|---|---|---|
| $R^2$ | 17.0% | | | |
| Degrees of freedom | 12,344 | | | |
| | Coefficients | Standard Error | t Stat | Confidence |
| $\Gamma$ | 0.00016 | 0.00107 | 0.1484 | 12% |
| $\alpha$ | -0.06002 | 0.00120 | -50.2174 | 100% |
| $\beta$ | -0.00374 | 0.00401 | -0.9320 | 65% |

Finally, in order to check the possibility that the non-recoverable degradation impacts the structure of the heat rate curve (changes $\alpha$) I used an alternative specification based on the product of FirstYear and the logarithmic change in generation:

(3) $\Delta \text{Ln HR} = \alpha \Delta \text{Ln Gen} + \chi\ (\text{FirstYear} \times \Delta \text{Ln Gen}) + \Gamma$

I also estimate model (3) both on the full dataset and on the non-restructured states:

**Table 9. Model (3) applied to the full monthly dataset**

| | | | | |
|---|---|---|---|---|
| $R^2$ | 17.0% | | | |
| Degrees of freedom | 21,662 | | | |
| | Coefficients | Standard Error | t Stat | Confidence |
| Γ | -0.00029 | 0.00077 | -0.3739 | 29% |
| α | -0.05811 | 0.00093 | -62.474 | 100% |
| χ | -0.01678 | 0.00338 | -4.95985 | 100% |

**Table 10. Model (3) applied to the non-restructured states**

| | | | | |
|---|---|---|---|---|
| $R^2$ | 17.0% | | | |
| Degrees of freedom | 12,344 | | | |
| | Coefficients | Standard Error | t Stat | Confidence |
| Γ | -0.00011 | 0.001033 | -0.10775 | 8% |
| α | -0.06017 | 0.001244 | -48.3728 | 100% |
| χ | 0.00185 | 0.004489 | 0.41251 | 32% |

**Q. What do these results show about non-recoverable degradation?**

A. These results are counter-intuitive. From Table 6 it appears that heat rates in the first year of operation improve rather than degrade. Model (2) implies the same thing, using both the full dataset and the data from non-restructured states. Model (3), when estimated using the full dataset, also appears to imply heat rates degrade less in the first year of operation than in subsequent years, but when estimated using the data from non-restructured states does show a (not statistically significant) degradation in the first year.

One way to interpret these counter-intuitive results is that time-averaged data, even using monthly period, are not precise enough to estimate the "non-recoverable degradation". This would also call into question the ability to make other quantitative statements about heat rate degradation based on average data, especially annual averages as Mr. Monsen used. Two other hypotheses would be that there is actually "breaking-in" period over the first year during which heat rates improve, or that the difference between "new and clean" heat rates and heat rates observed during actual operation has to do with the difference between a test environment and an operational environment rather than physical changes during the first year. I do not believe I have evidence to support either of those two positive statements.

**Q. What are your conclusions?**

A. It is my opinion that there are flaws both in the appropriateness of the data used for NIPPC's original analysis, and in aspects of the analysis itself. Mr. Monsen's testimony is apparently based on a similar analysis, but not exactly the same since his recommended "heat rate adder" is more aggressive than the original analysis would support. Still, even if we were to assume that NIPPC's analysis were correct and produced a number compatible with Mr. Monsen's recommendation, it does not by itself support the recommendation. The baseline of the NIPPC analysis is not consistent with the way that utilities estimate the heat rate in a benchmark bid.

Dispatch is clearly a significant variable to explain the historical changes in heat rates from one period to the next. Heat rate depends both on the level at which a plant is dispatched and the frequency of startups. The startup frequency is not captured in the publicly available data and the actual dispatch level cannot be precisely derived from data representing periods of a month or longer.

I attempted to correct publicly available heat rate data for changes in dispatch (generation). I found that the average corrected monthly degradation could not be distinguished from zero. Furthermore, Portland General Electric's opening testimony notes that turbine manufacturers give figures for "non-recoverable" heat rate degradation, which usually occurs during the first year of operation. Average heat rate changes during the first year of operation for plants installed during the years 2003-2010 are actually more negative than average changes for the same plants in later years, both before and after correction for changes in generation. Negative changes would indicate improvement, not degradation. Yet, turbine manufacturers apparently caution purchasers to expect degradation in the first year.

I conclude that publicly available heat rate and generation data for combined cycle units are unlikely to provide useful estimates of heat rate degradation. The figures that NIPPC derived in their original analysis are probably attributable to several of the data and methodological problems that Staff identified – vintage of the power plants, large number of simple cycle gas turbines, questionable eliminations – as well as the fact that NIPPC did not try to correct for generation changes. A better estimate might be derivable from a historical database of the results from actual efficiency tests; however, constructing such a database would be expensive and time-consuming and I am unaware of an existing and available data source.

## B. Cost Over-Run / Under-Run

**Q. What is the issue of cost over-runs and under-runs?**

A. Cost over-runs and under-runs are simple examples of estimation error. A cost over-run in a power plant occurs when the actual installed cost is greater than the estimate that formed the basis of the decision to construct the plant. An under-run similarly occurs when the actual cost is less than the estimate. If power purchase agreements with new power plants included ironclad assurance of delivery at a fixed price, but utility projects built based on benchmark bids passed actual costs to customers, then customers would be much more affected by cost over-runs and under-runs for utility benchmark bids than by those for projects with PPAs. Finally, if utility projects more frequently have over-runs than under-runs, then the estimation error could be considered to represent estimation bias.

**Q. Has any party's opening testimony alleged the existence of an estimation bias in utility benchmark bids?**

A. William Monsen, testifying on behalf of NIPPC, has suggested that utilities tend to underestimate costs and therefore experience cost over-runs. He has provided an analysis in his testimony of eleven UOG projects in California, and computed an average cost over-run of 7%.

**Q. Could an approach such as Monsen's be used to reveal estimation bias in utility benchmark bids?**

A. It is theoretically possible to estimate an "expected" cost over-run, e.g., the average percentage by which total costs placed into ratebase for individual projects tend to exceed the cost estimates. It would be very difficult to develop an appropriate database of project estimates and costs. The data would have to satisfy several conditions:

- The cost estimates would have to be verifiably those that were used to support a decision to pursue a utility project, or (preferably) a decision by a regulator to approve a utility's plan to construct such a project.

- The cost estimate should have been used as a basis for comparing the utility project with other alternatives, in a situation where the other alternatives could have been chosen had they been more cost-effective.
- The cost estimate should have been subject to the kind of scrutiny and mitigation that would be applied by an Independent Evaluator in Oregon.
- The actual construction cost should not have been increased by extraordinary costs which could have allowed for repricing of a competitive contract.
- Any past cost over-runs should be adjusted for the effects of price inflation, if the estimate was to be used in a solicitation whose model contract adjusted prices for inflation between project selection and commercial operation.

**Q. Why do you say it would be difficult to develop such a database?**

A. With effort, one can find estimates that supported the decision to pursue some utility projects. Mr. Monsen says he has done so for the eleven California projects. But it may not be possible to find enough to produce a good estimate. In particular, Mr. Monsen cites his own difficulty in obtaining the cost estimates for a number of Oregon projects. Even in cases where he found publicly available cost estimates, he appropriately questioned whether those cost projections were the ones that had been used to compare the utility project with other alternatives.

PA Consulting staff under my direction did a quick scan of publicly available data, looking for datasets of actual and estimated costs of gas-fired power plants. PA was unable to find good consistent data.

**Q. Do the project cost estimates in the Monsen testimony satisfy the conditions listed above?**

A. No. In general there is no evidence provided that the estimates were subject to the same kind of scrutiny as would have been applied in Oregon, nor that they were used as the basis for a competitive comparison with other alternatives. I can provide more detail about several of these projects.

**Q. Please discuss the project(s) with the largest cost over-run.**

A. The largest cost over-run in the NIPPC testimony is associated with four SCE peaking power plants (Barre, Center, Grapeland and Mira Loma). In Decision (D.) 10-05-008,[6] the California Public Utilities Commission allowed SCE to recover $260 million in costs for these four plants. Mr. Monsen quotes an estimate of $250 million for five peaking power plants, and prorates that to obtain an estimate of $200 million for four. The approved cost represents a 30% cost increase.

**Q. Why is that cost estimate not a good basis for comparison with Oregon benchmark resources?**

A. SCE was ordered to install UOG peaking resources by Commissioner Michael Peevey.[7] This order did not reference any cost estimate. The plants are not placed in competition with any other resources, and in fact are exempted from an ongoing solicitation process. SCE was permitted to establish a memorandum account in which to record the costs for later reasonableness review with no explicit standard, and D.10-05-008 does not compare actual costs to any prior estimate. I have not found the original source of the $250 million estimate, but it is referenced in the Resolution approving the establishment of the memorandum account and in some SCE testimony in the proceeding in which the

[6] Exhibit 103 to NIPPC's opening testimony.
[7] Assigned Commissioner's Ruling addressing electric reliability needs in Southern California for Summer 2007, in Rulemakings 05-12-013 and 06-12-013, August 15, 2006.

costs were approved for ratebasing.[8] That testimony notes that the original estimate was made under conditions of "limited time".

I do not believe the $250 million estimate was intended to be rigorous or binding. There was no reason for SCE to produce a rigorous cost estimate as the Commission had ordered SCE to build the plants. The order was not based on the cost estimate. None of the documentation I have reviewed indicates the costs were reviewed by an Independent Evaluator or other party. The estimate was not used as a basis for comparison with other alternatives. This is not the kind of estimate that Oregon utilities would be expected to provide for a benchmark bid and the fact that it was over-run is not relevant.

**Q. Please provide another example.**

A. The NIPPC testimony includes a 26% over-run on PG&E's Gateway plant. An earlier NIPPC document in this proceeding identified this over-run as attributable to a new State Water Board requirement for dry cooling.[9] An IPP plant in a similar situation would have been subject to the same unanticipated requirement, and would have incurred the same additional cost. Furthermore, it is likely that the Power Purchase Agreement would have assigned such Change in Law risk to the utility offtaker. In other words, the increase in actual construction cost would probably have allowed for repricing of a competitive contract. Even if the original cost estimate had been comparable to a utility benchmark bid, the over-run is one that would have impacted ratepayer costs whether it had been associated with a benchmark bid or an IPP contract. Therefore it should not be included in determination of a benchmark-specific bid adder.

[8] Note 12 in MRW & Associates, LLC, *Leveling the Bidding Field: Some Initial Steps Toward Fairly Comparing Proposals for Utility-Owned Generation and Independent Power Projects*, Oakland CA, Nov. 16, 2011, p. 11, submitted in this proceeding.
[9] MRW & Associates, op. cit., p. 11.

**Q. Did you also review Mr. Monsen's statements about deferred construction costs?**

A. Yes, I did.

**Q. What is the gist of Mr. Monsen's position?**

A. Mr. Monsen correctly notes that utilities – indeed all plant owners – make capital expenditures during the entire lifetime of a power plant. He provides an example of a single power plant which faced a $14 million capital expenditure after commercial operation, which he attributes to a construction defect. He states that this should be considered a construction cost and hence an over-run relative to the reported cost. He then states that any capital expenditure shortly after commercial operation, which exceeds the annual depreciation on the plant, is really a deferred construction cost and should count as an over-run.

**Q. Do you agree with Mr. Monsen's position?**

A. No. A single example of a sizable capital expenditure made after commercial operation but which arguably should have been made during construction hardly proves that all post-operation capital expenditure are deferred construction costs. Furthermore, by trying to use this to justify an adder to be included in benchmark bids, Mr. Monsen implicitly assumes that the financial models from which the benchmark bids are derived do not contain any capital expenditures during the first five years that exceed depreciation.

**Q. How does Mr. Monsen attempt to estimate the size of such an adder?**

A. He says that he computed capital expenditures by plant for the set of projects he used in his analysis of cost over-runs, by comparing the values in line 17 of p. 402 of the utility owner's FERC Form 1. He added depreciation, based on depreciation rates found on p.337 of the FERC Form 1, and expressed the result as a percentage of the cost of the plant in its first year of service, which I assume he got from p. 402, line 17 of that year's FERC Form 1. He then computed the average percentage for each power plant, and created a capacity-weighted average over all the plants.

**Q. Was he able to apply this method to all of the power plants whose construction costs he had studied?**

A. No, he says he was unable to get good data for the Mountainview and Humboldt plants.

**Q. What does he say was his numerical result?**

A. He proposes an adder of 5.7% per year for the first five years of operation, which would be a total of 28.5% of the initial cost. By comparison, the $14 million expenditure he used as his justification, which I would assume is an extreme case chosen to make a point, is only 23% of that plant's $60 million construction cost.

**Q. Is Mr. Monsen's five-year period justified?**

A. It appears to be chosen arbitrarily. I am not sure why one should assume that "deferred construction expenditures" persist for five years. Furthermore, he has data for only one plant, Palomar Energy Center, which came online before 2009. As the latest FERC Form 1s currently available are for 2011, he can have no more than two observations of capital expenditure for a plant that came online in 2009 or later.

**Q. Were you able to construct a dataset similar to the one used by Mr. Monsen?**

A. Yes. I was able to obtain copies of the utilities' FERC Form 1s and do the computations Mr. Monsen describes, with one exception.

**Q. What was the exception?**

A. San Diego Gas & Electric's FERC Form 1 reports both Miramar plants together. I can therefore compute the figures for Miramar I through 2008, and for the combination of Miramar I and II thereafter.

**Q. Did you verify Mr. Monsen's 5.7% figure?**

A. No. Table 11 shows the annual values in line 17 of FERC Form 1 page 402.

**Table 11. Total plant capital costs by year, from FERC Form 1**

| | Total Plant Cost (K$) | | | | | | |
|---|---|---|---|---|---|---|---|
| Plant | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
| Barre | | | 62,887 | 65,990 | 70,731 | 72,922 | 77,028 |
| Center | | | 64,387 | 68,384 | 72,294 | 75,181 | 79,333 |
| Grapeland | | | 56,701 | 62,992 | 65,340 | 67,831 | 71,715 |
| Mira Loma | | | 55,716 | 59,081 | 61,700 | 62,175 | 68,758 |
| Gateway | | | | | 438,069 | 445,555 | 447,237 |
| Miramar I | 33,436 | 33,885 | 33,885 | 34,184 | | | |
| Palomar | | 467,681 | 469,618 | 490,518 | 502,795 | 509,111 | 539,398 |
| Colusa | | | | | | 645,020 | 651,885 |
| Miramar I + II | | | | | 83,668 | 84,621 | 88,845 |

Next, Table 12 displays the changes in those values relative to the first-year values, averaged by plant and then converted to a capacity-weighted average. I note that the percentage changes after 2009 in the total cost of Miramar I and II are assumed to apply to the first years of Miramar II as well as the fourth and fifth years of Miramar II:

**Table 12. Annual capital cost increases relative to first-year cost**

| | Relative Cost Increase (%) -- NOT net of depreciation | | | | | | |
|---|---|---|---|---|---|---|---|
| Plant | Capacity | Y1 | Y2 | Y3 | Y4 | Y5 | AVERAGE |
| Barre | 49 | 4.93% | 7.54% | 3.48% | 6.53% | | 5.62% |
| Center | 49 | 6.21% | 6.07% | 4.48% | 6.45% | | 5.80% |
| Grapeland | 49 | 11.10% | 4.14% | 4.39% | 6.85% | | 6.62% |
| Mira Loma | 49 | 6.04% | 4.70% | 0.85% | 11.82% | | 5.85% |
| Gateway | 580 | 1.71% | 0.38% | | | | 1.05% |
| Miramar I | 48 | 1.34% | 0.00% | 0.89% | 1.14%* | 5.05%* | 1.69% |
| Palomar | 566 | 0.41% | 4.47% | 2.63% | 1.35% | 6.48% | 3.07% |
| Colusa | 659 | 1.06% | | | | | 1.06% |
| Miramar II | 48 | 1.14%* | 5.05%* | | | | 3.09% |
| Capacity-weighted average | | | | | | | 2.12% |
| Miramar I + II | | 1.14% | 5.05% | | | | |

*-Values taken from Miramar I and II

**Q. Did you adjust these figures for depreciation?**

A. No, I believe Mr. Monsen erred in doing so. It had been my understanding that "Cost of Plant", as reported on lines 13-17 of page 402 of the FERC Form 1, referred to undepreciated cost – it should not be necessary to add back depreciation. I asked Portland General Electric to ask staff involved in the production of FERC Form 1 what those lines represented and they reported back to me that they represented undepreciated costs.

**Q. Did you attempt any independent verification?**

A. Although the FERC Form 1 tables do not appear to break out depreciation by plant, such a breakout can sometimes be found in other materials included in the Form 1. For example, I looked at the Notes to Financial Statements in Southern California Edison's 2010 Form 1 (page 123.38). That included a breakout of SCE's original investment in four jointly-owned plants and the accumulated depreciation against those investments. I computed the depreciated net investment and compared it to the total costs from line 17 of page 402. The results are given in Table 13.

**Table 13. Undepreciated and depreciated investments in SCE jointly owned plants, in $Millions**

| Plant | Investment in Facility | Depreciated net investment | Total Cost (p 402, line 17) |
|---|---|---|---|
| Four Corners Units 4 and 5 | 596 | 97 | 583 |
| Mohave | 347 | 35 | 313 |
| Palo Verde | 1,899 | 356 | 1,829 |
| San Onofre | 5,369 | 1,289 | 4,745* |

*-Units 2 and 3

It is clear that the costs on page 402 are of the same magnitude as the undepreciated investments, and much greater than the depreciated values. The difference for San Onofre is probably owing to the absence of Unit 1. Remaining differences between the "Investment in Facility" and "Total Cost" columns probably represent differences between GAAP and FERC accounting.

Q. **You have displayed a figure of 2.12% for annual capital expenditures for this set of power plants. Do you believe it is an accurate and unbiased estimate of "deferred construction costs"?**

A. No. Most of the above-average annual increases are attributable to the SCE peakers on the fifth year of operation. I have already explained that the SCE peakers were developed quickly under CPUC order so it is not surprising that some construction costs were incurred after operation; they are not representative. Second, the choice of a five-year period was arbitrary and in both cases where five years of data are present (Miramar and Palomar) the year 5 costs are higher than any other year. Year 5 also does not appear to be representative, which highlights the arbitrariness of the choice to use a five-year average.

**Q. What is your conclusion?**

A. I conclude that there are few good examples of utility projects, with cost estimates that are of the same nature as utility benchmark bids in Oregon, that can be used to create an expected figure for utility cost estimation bias. Such bias is probably best eliminated by the Independent Evaluator's active scrutiny of the benchmark bids.

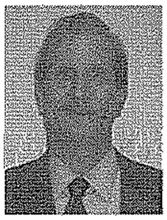
Historical examples of cost over-runs do not by themselves imply that utility benchmark bids are consistently underestimated. Oregon utilities may apply a level of rigor to their benchmark bids not present in estimates presented to regulators for other utility power plants. I examined the examples presented in Mr. Monsen's testimony. The largest cost over-runs are associated with combustion turbines that were built on an expedited basis. I do not think that the estimate that Mr. Monsen has characterized as the initial cost for those plants was intended as the basis for project approval, but instead there is evidence that the California Public Utilities Commission set up a mechanism explicitly to account for estimation error.

Furthermore, cost over-runs are not unique to utility projects, as is shown by Mr. Monsen's second example. Mr. Monsen attributes the over-run in the PG&E Gateway project to a regulatory change. Under many PPAs that risk would be borne by customers.

Finally, Mr. Monsen suggests an adder for "deferred construction costs" that is about five times the size of the proposed over-run adder. The justification for the adder is weak, and I believe the computations that Mr. Monsen says he made to support it rely on an erroneous interpretation of FERC Form 1 data.

# III. Credentials

Jonathan Jacobs — Curriculum vita



Jonathan Jacobs has twenty-seven years' experience as a consultant, manager and tool builder, including twenty-two years' experience in the electricity industry on both the regulated and unregulated sides. Dr. Jacobs is an expert in the use of mathematical models and quantitative tools in electricity operations and markets. He manages PA's US practice in the review and certification of ISOs' market models, processes and systems, which provides and evaluation of the dispatch and pricing of $20 billion worth of energy as well as ancillary services. He understands the issues around integrating renewables into the grid, having served as an Independent Evaluator of renewable-specific contract solicitations by a California utility and contributed key intellectual content to a new renewable-markets venture. He is a skilled communicator, having provided testimony to state and Federal regulators on the reasonableness of utility practices, appropriate risk metrics, and other topics. Prior to joining PA he served as Director, Market and Financial Modeling for a deregulated energy retailer. In that position he was responsible for the methods and tools the company used to price retail power contracts, for competitive analysis of utility rates, for monitoring the progress of electric industry restructuring in various jurisdictions to identify profitable target markets, and for forecasting the company's own load obligations. He has worked on diverse modeling applications including hydro forecasting and scheduling, contract valuation, portfolio analysis and system reliability modeling. He has developed large and small decision support systems, developed algorithms and managed projects of sizes ranging from $10,000 to $2,000,000. His doctorate is in mathematics.

| Primary expertise | Related experience | Qualifications | Client list |
|---|---|---|---|
| • Energy market structures<br>• Renewable capacity requirements and markets<br>• Resource planning and procurement<br>• Mathematical and statistical modeling | • Software certification<br>• Full-requirements pricing<br>• California energy markets | • PhD, Mathematics<br>• Member, Institute for Operations Research and Management Sciences (INFORMS) and International Association for Energy Economics (IAEE) | • Ontario IESO<br>• ISO New England<br>• San Diego Gas & Electric<br>• City of Los Angeles<br>• |

## Primary expertise

**Resource planning and procurement** – Independent evaluation of solicitations for renewable energy; procurement process design and implementation; resource portfolio modeling

**Organized power markets** – Review and certification of software used to clear and settle energy and capacity markets; consultation on market design and structure

**Capacity requirements** – Renewable portfolio standards and market-based approaches to fulfilling those standards

**Mathematical modeling of energy assets** – Use of optimization and simulation models to project asset operation and cash flows.

## Key related achievements

**San Diego Gas & Electric Company (March, 2006- present)**– Since 2006, Jonathan has been the Independent Evaluator of resource procurements for a US utility with approximately 4500 MW peak load, including an all-source procurement (2006), a peaking capacity procurement (2006), procurements particularly directed at small-scale renewables, both by power purchase and turnkey construction, and renewable-specific procurements (2006, 2008, and 2009) through which the utility sought to increase its renewable procurement from approximately 5% of load (800,000 MWh) to 20%. He has also been advisor on procurement design and execution, and evaluator both of individual offers and of the utility's conduct of the solicitation.

**Multiple clients (April - November, 2012)** – Jonathan developed and led a benchmarking study of the efficiency and cost of energy procurement -- both purchased power and fuel for generation -- across a diverse set of utilities. The respondents were diverse in terms of geography, size and ISO participation.

**Pacific Gas & Electric Co. (2012)** –Jonathan advised the utility on practices elsewhere in several areas of utility energy procurement including integrated resource planning, price-based maintenance schedule, cost forecasting and procurement incentive mechanisms.

**ISO New England (July, 2004 - present)** – As Assignment Manager since 2005, Jonathan has certified the correctness of multiple components of the dispatch and pricing software, as well as auctions for forward obligations for operating reserves and capacity credits. In particular, the Forward Capacity Auction is a descending-clock auction with locational computation of market-clearing prices. During 2004, as a technical expert, Jonathan personally validated a particularly complex mathematical model used to impose security constraints upon the commitment and dispatch used to compute Locational Marginal Prices.

**City of Los Angeles (April, 2011 - present)** – Jonathan has managed an ongoing review, on behalf of the City Council, the cost structure of the Department of Water and Power including all aspects of water and electricity supply and the Department's Integrated Resource Plan. Jonathan also reviewed proposed rate structure changes. This work built on a prior assignment in which PA examined the Department's energy costs (under a pass-through clause) and an associated rate proposal.

**EDI Holdings (Pty) Ltd. and the National Energy Regulator of South Africa (April - October, 2008)** – Jonathan developed a report on design considerations for a contract based market structure to support the development of independent power plants, possibly involving a "Single Buyer" of new capacity.

## Additional experience

**New York Independent System Operator (April, 2006 - Oct. 2010)** – As Assignment Manager, Jonathan certified the correctness of several releases of NYISO's settlements engine and market software (including real-time security-constrained economic dispatch, day-ahead security-constrained unit commitment and locational pricing). These systems are used to manage day-ahead and real-time scheduling of over 165,000 GWh of energy annually, and to settle transactions with an annual value of almost $10 billion. Certification ensures that these complex systems and the mathematical models they embody are faithful to their formulations and to the market structure defined in the tariff. Certification includes the design and conduct of appropriate system tests

**Eskom Holdings (South Africa) (Oct. - Dec. 2011)** – Jonathan managed PA's engagement, as a subcontractor, to provide expertise in ISO structure and markets around the world. The larger assignment in which PA was involved was a due diligence study of the impacts on the incumbent utility of the potential implementation of an Independent System and Market Operator.

**Independent Electricity System Operator (Ontario) (Dec. 2010 - Nov. 2011)** – Jonathan led the testing and certification of substantial changes to the software that implements the day-ahead commitment market – referred to as Enhanced Day-Ahead Commitment (EDAC).

**EDI Holdings (Pty) Ltd. (Oct. 2010 - Jan. 2011)** –Jonathan led a project to assess European models for the restructuring of the South African electricity industry, with an emphasis on metropolitan and municipal distributors.

**Independent Electricity System Operator (Ontario) (Dec. 2010 - Nov. 2011)** – Jonathan led the testing and certification of substantial changes to the software that implements the day-ahead commitment market – referred to as Enhanced Day-Ahead Commitment (EDAC). Jonathan had previously led a review of the detailed design of the market changes, in order to ensure it was consistent with the plan reflected in the modifications made to the IESO tariff. The design included rules for market clearing and 120 pages of settlement equations and procedures, suggesting many improvements and corrections.

**Independent Electricity System Operator (Ontario) (April 2009 - Jan. 2010)** –Jonathan led a review of the detailed design of the market changes, in order to ensure it was consistent with the plan reflected in the modifications made to the IESO tariff. The design included rules for market clearing and 120 pages of settlement equations and procedures, suggesting many improvements and corrections.

**Confidential client** – From 2007 to 2009, Jonathan generated and elaborated key intellectual capital for a new business venture to streamline renewables procurement and facilitate the development of renewable generation.

**New York Power Authority** – In 2010, Jonathan led a project to develop a business case for a system to model generation and develop "ideal" schedules as a basis for performance metrics. He had previously led a project to identify and characterize appropriate metrics for generation bidding. In 2008, as the leader of a team of PA consultants Jonathan assessed the need for and potential benefit of an optimal bidding system for the Niagara Power Project, and presented the assessment to NYPA management.

**Confidential client – Jonathan assisted the utility to prepare for a regulatory audit of its load forecasting and supply planning functions by conducting a series of interviews and identifying gaps relative to best practices.**

**National Grid** – In 2009, Jonathan developed and delivered technical training in the concept and operation of a mathematical model for valuing a portfolio of fuel and transportation contracts

**Pacific Gas & Electric Co.** –Jonathan advised the utility on the design of tools and processes to monitor ISO dispatch and prices and on the potential enterprise risk exposure from its commodity operations. In 2008, he provided confidential regulatory analysis. In an earlier assignment, he evaluated the design of an auction for an "open season" on transmission capacity to identify any unanticipated problem areas or gaming opportunities

**Calpine Corp.** –Jonathan led the development of a suite of individual cash flow models for power contracts (mostly cogenerators) to support the valuation and restructuring of those contracts

**Portland General Electric** –Jonathan specified and prototyped a cost simulation model, compatible with an in-house spreadsheet-based simulation model, that could be used to estimate the statistical properties of the distribution of PGE's net variable power costs

**Alberta Independent System Operator** –Jonathan reviewed the data and processes used by this Canadian transmission operator to forecast load. He also surveyed similarly situated entities, in the US and internationally to ascertain best practices

**Puget Sound Energy** –Jonathan developed and implemented a method to weather-normalize demand and usage forecast by customer category, for use in rate setting. He supported utility staff in dealing with regulators and in subsequent workshops on how to regularize the use of weather normalization in the future

**Cinergy / CG&E** – Jonathan wrote a report explaining the bases for pricing default or provider of last resort (POLR) service in multiple US jurisdictions where the electricity for that service is bought from competitive markets, through auctions or Requests for Proposal, and compared the cost to the consumer in those jurisdictions. The work was used in a regulatory proceeding to set the utility's own default or POLR pricing

**Xcel Energy** – Jonathan testified twice on behalf of this utility: FERC testimony on the utility's use of a unit commitment model to estimate the avoided cost of power transactions, for use in computing charges and credits under a fuel clause; and Colorado PUC testimony on the utility's use of a rule-based model for allocated power costs between native load and external transactions, in comparison with the use of unit commitment and production simulation models

**MBIA Corp.** – Jonathan advised on developments in the California energy markets and California regulation and analyzed the impacts of those developments (and of related bankruptcy filings) on the finances of Pacific Gas & Electric, Southern California Edison, the California Independent System Operator and the California Department of Water Resources

**La Paloma Generating Co.** – Jonathan developed a suite of optimization models for plant scheduling against price expectations, taking into account a complex tolling agreement. The models were fielded in Excel spreadsheets

**Southern California Edison** – Over an extended period in 2002 and 2003, Jonathan assisted the utility in preparing to resume power procurement, with a particular emphasis on valuing wholesale power contracts and tolling agreements. He designed and implemented a contract valuation tool; helped evaluate tools for short-term operations planning and scheduling; and developed a contingency plan to be executed if vendor-supplied tools for risk management and settlement failed

**Statoil ASA** – Jonathan estimated the value of a "redirection option" for liquefied natural gas shipments, specifically, whether as part of an LNG shipping plan it was worthwhile to procure capacity at a second terminal, in a distinct geographic market

**PSEG Power** – Jonathan projected the likely clearing price for New Jersey's auctions of the responsibility for providing basic generation service, based on forward prices of energy, capacity and ancillary services, and a consistent set of risk premia. The initial forecast, prior to any such auctions having been conducted, tracked quite closely to actual results.

## Additional experience

**PG&E Energy Services Co. – Director, Market and Financial Modeling – 1997–2000** – Led a staff of 9 professionals, including engineers, computer modeling specialists, economists and forecasters, based in two separate locations, with the responsibility for analysis and mathematical modeling to support the company's commodity power sales, and participate in the development of strategy and tactics for the retail power business. Developed PG&E Energy Services' computer tool for pricing retail power contracts, which allowed the company to originate one of the largest contract portfolios in California. Directed the development of computer modeling for electricity pricing in emerging markets outside California.

**Pacific Gas & Electric Co. – Project Manager / Team Leader – 1990–7** – Led a group of regular and contract employees responsible for the specification, selection, design, implementation and integration of mathematical models and decision support systems for medium- and long-term planning for PG&E's electricity supply business. Led the development of an Integrated Generation, Transmission and Distribution (IGTD) planning model aimed at distributed generation, and of an "energy reliability" model. Technical lead for hydroelectric scheduling and stream flow modeling.

## Education

Ph.D., Mathematics, The University of Wisconsin, Madison.

M.S., Mathematics, The University of Wisconsin, Madison.

S.B., Mathematics, The University of Chicago.